COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY	))))	CASE NO. 2024-00326

INITIAL COMMENTS OF JOINT INTERVENORS KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, METROPOLITAN HOUSING COALITION, AND MOUNTAIN ASSOCIATION ON THE 2024 INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Cassandra McCrae
Gilbert Zelaya
Earthjustice
1617 JFK Blvd.
Ste. 2020
Philadelphia, PA 19103
(215) 671-6493
cmccrae@earthjustice.org
gzelaya@earthjustice.org

Byron L. Gary
Ashley Wilmes
Kentucky Resources Council
P.O. Box 1070
Frankfort, Kentucky 40602
(502) 875-2428
Byron@kyrc.org
Ashley@kyrc.org

Counsel for Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association

Dated: March 07, 2025

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INITIAL COMMENTS OF JOINT INTERVENORS KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, METROPOLITAN HOUSING COALITION, AND MOUNTAIN ASSOCIATION ON THE 2024 INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS & ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association (collectively, "Joint Intervenors") appreciate the opportunity to offer these comments in response to the 2024 Joint Integrated Resource Plan ("IRP") of Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU" or "the Companies"). These comments include the accompanying Report prepared by the Applied Economics Clinic as well as several attachments.

1. Introduction

Integrated Resource Planning is a complex undertaking with serious affordability and reliability implications for customers. The Companies' 2024 IRP comes at a time of considerable uncertainty, with great risks facing aging and increasingly uneconomic resources, an incredible mix of technological potential, and potentially irrational forecasts of load growth.

Unlike the 2021 IRP, the Companies do appear to propose a plan that they provisionally expect to pursue, and have already applied for Certificates of Public Convenience and Necessity authorizing over $3.7 billion in new supply-side capital projects outlined in their preferred portfolio set out in the IRP.

Joint Intervenors' comments are informed in substantial part by the work of experts Joshua Castigliego and Elizabeth Stanton of the Applied Economics Clinic (AEC). As explained in the AEC White Paper, Attachment JI-1, the 2024 IRP falls short of several best practices in long-range resource planning, beginning at the load forecasting stage and running through IRP report and stakeholder participation. The AEC White Paper is adopted and incorporated in these Comments in its entirety. Joint Intervenors' silence on any issue, analysis, or conclusion advanced in the Companies' IRP should not be taken as support. Key observations from the AEC White Paper include the following:

1. Customer load is overestimated resulting in an exaggerated recommendation of necessary supply resources.
2. Faulty resource costs and fuel prices obscure essential cost comparisons between resource plans.
3. Scenarios are modeled using unreasonable assumption value ranges and are not replaced with useful ranges to explore true risks.
4. A preferred resource plan is selected without comparing costs across potential resource plans and without testing the preferred plans' sensitivity to alternative future scenarios.
5. No non-cost criteria are used in the selection of a preferred plan.
6. Stakeholder input was not considered in the development of the resource plan.
7. The IRP lacks a non-technical presentation of results demonstrating the Companies' plan selection process.[1]

As a result of these serious and consequential flaws, the usefulness and validity of the IRP is questionable. Accordingly, the Companies' IRP cannot be relied upon to support the selection of new resources in near-term CPCN applications. Ultimately, based on information developed to date, Joint Intervenors encourage the Companies to adopt, and the Commission Staff's Report to recommend that future IRPs incorporate,

[1] Attach. JI-1, AEC White Paper, *LG&E-KU's 2024 Integrated Resource Plan: An Assessment,* Section IV.

the following general improvements, in addition to the more detailed discussion and recommendations that follow:

1. The Companies should assess the effects of all aspects of the resource plan and their operations in general on ratepayers, particularly the most vulnerable.
2. The Companies should use the IRP process to develop a resource plan, not a range of scenarios which are ultimately not those that are recommended.
3. Given the significant apparent potential for load growth in particular, the Companies should more reasonably assess and justify load projections, as well as potential effects of planning around high load scenarios on current ratepayers, particularly if load growth fails to manifest.
4. The Companies have been urged to already, and certainly must consider a full range of possibilities, including future carbon scenarios as well as the untapped potential of demand side management and distributed resources, and the effect of the Companies' role in encouraging or blocking those scenarios on ratepayers.
5. The Companies must also evaluate chosen "no regrets" portfolios against the full range of scenarios developed at the outset, and demonstrate that the portfolio is indeed "no regrets."

2. Background

a. The Companies

LG&E/KU combined serve roughly 1 million customers in Kentucky and Virginia, and operate roughly 7,500 megawatts of regulated generating capacity. Both wholly-owned subsidiaries of utility holding companies PPL Corporation and LKE, the Companies' 2023 rate base was roughly $12 billion, with $3.5 billion in annual operating revenues and net income of over $552 million.[2]

LG&E/KU's regulated utility business significantly supports PPL's bottom-line and attractiveness to investors. Of PPL's nearly $20 billion 4-year capital expenditure plan, roughly half of those capital expenditures will be made through LG&E/KU, with LG&E/KU ratepayers to pay an estimated $9.875 billion on new capital projects from 2025 to 2028, plus the Companies' approved rate of return on all that capital project spending.[3]

Table 1 - PPL's Capital Expenditure Plan for LG&E/KU ($ in millions)

Type	**2025**	**2026**	**2027**	**2028**	**4-year Total**
Electric Distribution	$400	$475	$475	$475	**$1,825**
Electric Transmission	$250	$425	$475	$475	**$1,625**
Electric Generation - non-Coal	$725	$875	$1,325	$1,025	**$3,950**
Electric Generation - Coal Fired	$250	$325	$375	$300	**$1,250**
Gas Operations	$175	$100	$125	$125	**$525**
Other	$250	$225	$125	$100	**$700**
Total Utility Capex	**$2,050**	**$2,425**	**$2,900**	**$2,500**	**$9,875**

[2] PPL Corporation, 2024 Annual Report at 1-2, *available at* https://filecache.investorroom.com/mr5ir_pplweb2/1187/PPL_2024_Q4_Investor_Update_Final.pdf.

[3] Attach. J-2, PPL Corporation, 2024 Q4 Investor Update at 23 (Feb. 13, 2025).

Roughly half of PPL's ongoing earnings per share in 2024 flowed from LG&E/KU customers.[4] Since the Companies' 2021 IRP, PPL reports combined annual growth rates of 7-8%, and forecasts a 9.8% compound annual growth rate (CAGR) for annual rate base growth through 2028—a notable increase over previous estimates of a 6.3% rate base CAGR.[5]

Rewarding that extended growth, PPL increased its quarterly common stock dividend last year, paying $0.2725 per share—contributing to an annualized dividend of $1.09 per share.[6] With roughly 738.29 million outstanding shares, that dividend level translates into $804 million paid out annually in shareholder dividends.

Companies last received approval for a general rate increase in June, 2021. As part of a settlement agreement in that case with the same set of Joint Intervenors as this case, as well as all other parties, the Companies agreed to a "stay out" provision.[7] The Companies' "stay out" period from that case ends July 1, 2025,[8] and the Companies' expect to seek a base rate increase in the first half of 2025.[9] From a rate base of $12.4 billion at the end of 2024, PPL expects LG&E/KU's rate base to increase

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[4] *Id*. at 10 (reporting $0.34 in Q4 2024 Ongoing Earnings, with $0.17 attributed to LG&E/KU; reporting $1.69 in 2024 Ongoing Earnings, with $0.84 attributed to LG&E/KU).

[5] *Id.*at 15.

[6] *Id.*at 17.

[7] *Elec. Application of Ky. Util. Co. for an Adjustment of Its Elec. Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349,Order at 11-13 (Jun. 30, 2021); and, *Elec. Application of Louisville Gas and Elec. Co. for an Adjustment of Its Elec. and Gas Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Order at 13-15 (Jun. 30, 2021).

[8] *2020-00349* at 11-13, and *2020-00350* at 13-15.

[9] Attach. JI-2 at 7.

to $18.6 billion by 2028, increasing by roughly one-third, and constituting nearly half of PPL's overall projected rate base over the same period.[10]

b. LG&E-KU Ratepayers

Affordability is a growing concern in the Companies' service territory, and does not affect all ratepayers equally.

According to EIA data, each of the Companies' average retail electric rates has increased by more than 50% from 2010 to 2023, nearly the period of time used in IRP planning.[11] Since 2009, the Residential Basic Service Charge more than doubled as well, increasing from $5 to $12.60-16.43.[12] Over the twelve months "ending June 30, 2024, the total amount of all Kentucky residential electric customer arrearages was approximately $22.2 million."[13] Some customer arrearages result in disconnection and lost electric (and potentially gas) service until arrearages are paid or the customer enters into a payment plan. From February 2020 to June 2024, the Companies disconnected residential electric service on 318,323 occasions.[14] The Companies did not state the average length of those disconnections.[15] In the 12-month period ending June 30, 2024, in lieu of disconnections for non-payment, the Companies could have paid down all arrearages by reducing shareholder dividends by roughly $0.03/share.

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[10] *Id*. at 24.

[11] Notably, on an annualized basis, both Companies' average retail electric rate increased more than the 2.3% per year rate increase assumption relied upon in the Companies' load forecast. IRP Vol. I at 5-19. To the extent that 2.3% per year is factually consistent with long-term inflation expectations, this would imply that the Companies' average retail electric rate also increased more than general inflation.

[12] Compare LG&E, P.S.C. Electric No.7, First Revision of Original Sheet No. 5 (effective Jun. 29, 2009), with P.S.C. Electric No. 13, Fifth Revision of Original Sheet No. 5 and P.S.C. No. 20, Fifth Revision of Original Sheet No. 5.

[13] Companies' Resp. to JI 2.31(l)(i).

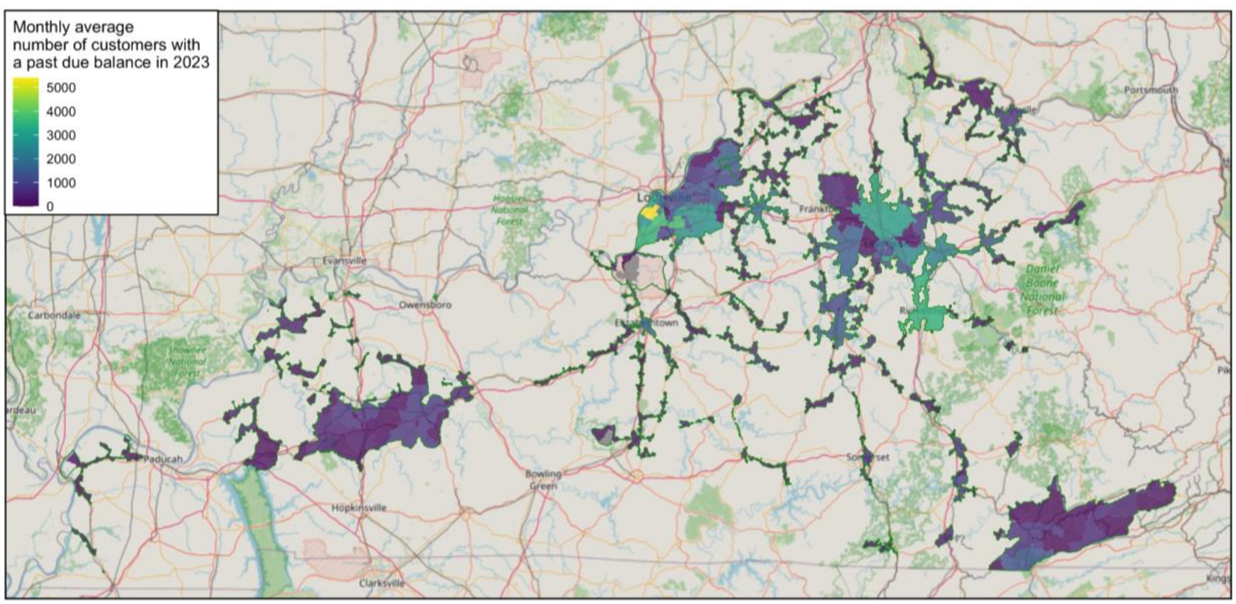
[14] Companies' Resp. to JI 2.31(k).

[15] Companies' Resp. to JI 2.31(k)(i).

The amount of residential arrearages appears to be dwarfed by those of large non-residential ratepayers. For instance, between 2020 and 2023 several zip codes with only one or two months with a single customer past due included arrearages in the thousands up to over a million dollars.[16] In one example, zip code 40225, which appears to contain only GE Appliance Park in Louisville,[17] the monthly average past due amount in each of the past three years ranged from $30,713.86 to $1,136,594.06.[18]

Other zip codes struggle with greater numbers of ratepayers with much smaller average past due balances, but higher numbers of disconnections. Figure 1, below, shows that the average range of customers with a past due balance across LG&E-KU's service territory varies by zip code from 0 to over 5,000.

Figure 1 - Number of customers with past due balance in 2023. Data from JI 2-36 attachment



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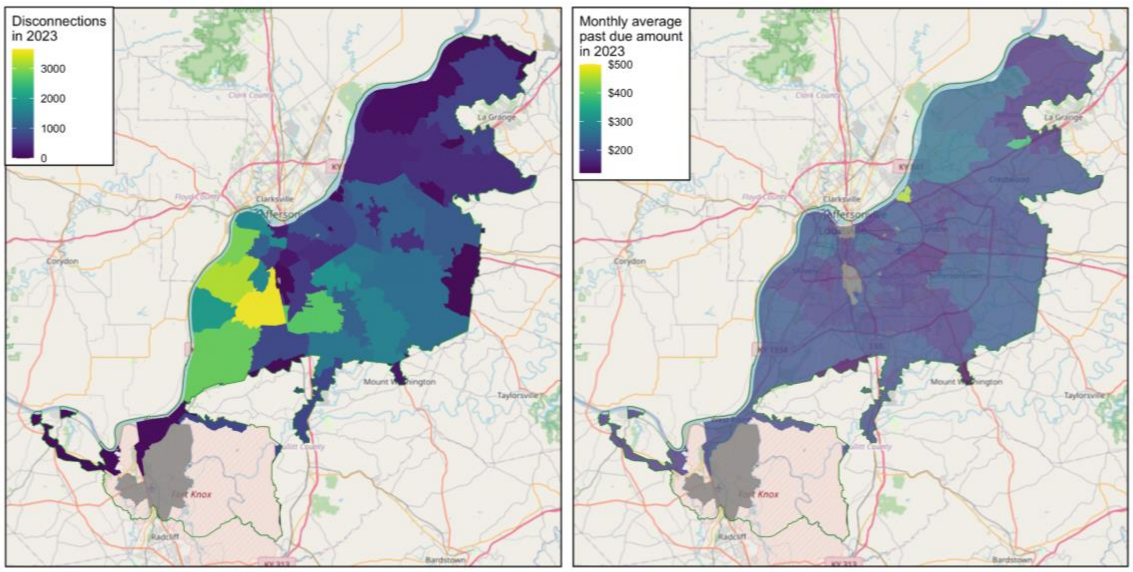
16 Companies' Resp. to JI 2.36, attachment.

17 *See* Louisville Metro Open Data, Jefferson County KY ZIP Codes, https://data.louisvilleky.gov/datasets/LOJIC::jefferson-county-ky-zip-codes/explore.

18 *Id.* at row 92.

Looking more closely at LG&E's territory, the highest numbers of disconnections by zip code typically have the lowest average past due amount, indicating large numbers of struggling ratepayers with small past due amounts being disconnected.

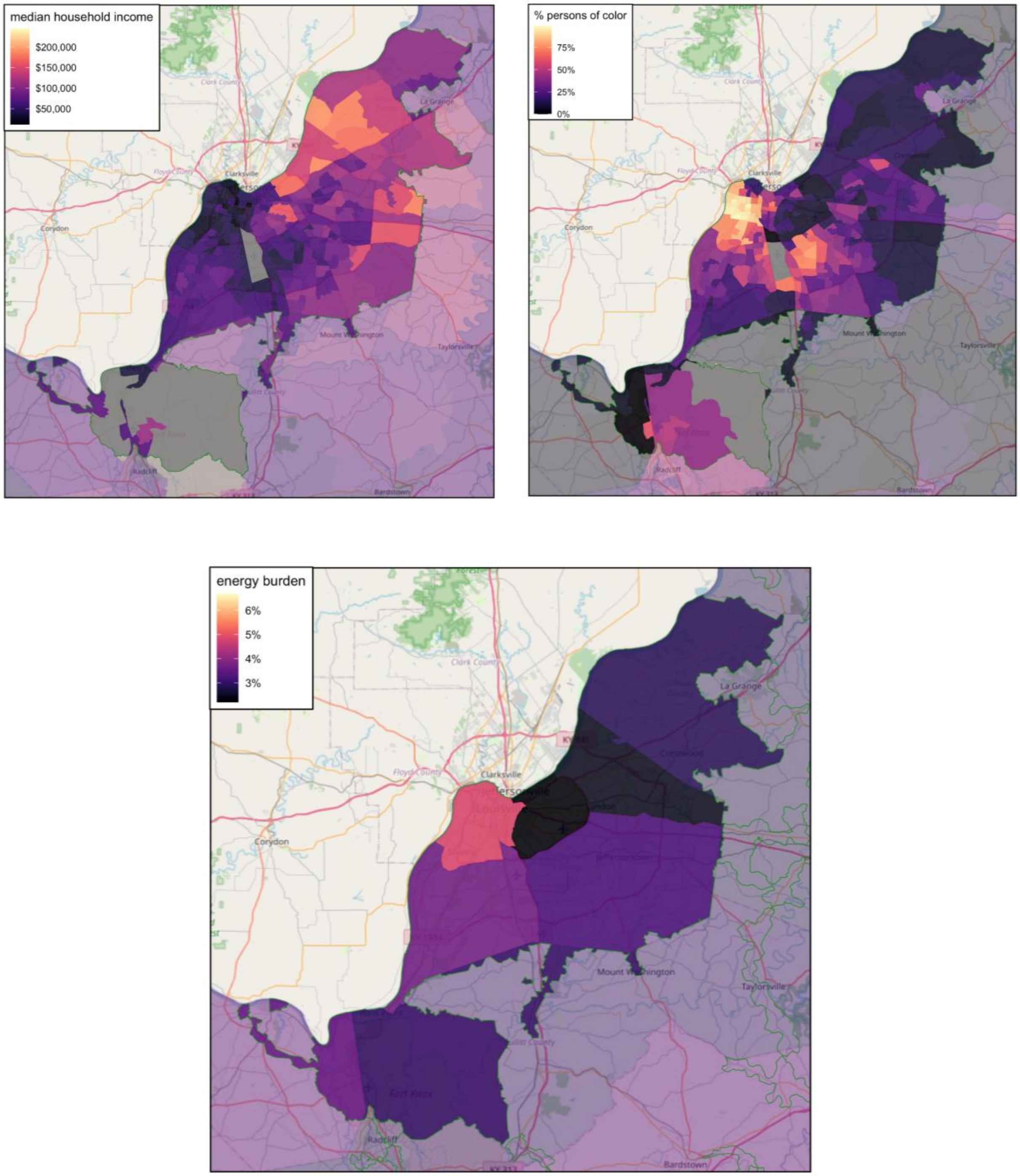
Figure 2 – 2023 LG&E disconnections and past due amounts. Data fromJI 1-55 and 2-36 attachments



In fact, the relationship varies almost perfectly inversely, with the lowest average past due amounts seeing the highest number of disconnects across LG&E-KU's territory. In a particularly stark example, the zip code with the highest number of disconnections, 40517 (south Lexington, 3982 disconnects, average past due amount $124.37) falls well below the median average monthly past due amount of $180. The average of the lowest bill amount between LG&E and KU leading to disconnection in 2023 was only $77.67.

The same zip codes with the highest average number of ratepayers with overdue balances (and lower overall average overdue balances), as well as highest frequency of disconnections, also line up with the areas with the lowest median household incomes, the largest numbers of persons of color, and the highest energy burdens, as shown in Figure 3 for LG&E territory.

Figure 3 - LG&E Territory Energy Burden, Percent Persons of Color, and Energy Burden. Data from 2023 American Community Survey (ACS).



c. Previous IRP

The Companies' last attempt at Integrated Resource Planning in 2021 was a fruitless exercise, as it became clear that the Companies did not propose a plan that they intended to implement in reality. Indeed, the Companies' 2021 IRP ended in abject failure, with the Commission Staff's Report concluding that "there does not appear to be a single party to this review—LG&E/KU included—who is likely to support implementing the optimal, base case plan at this point. Thus, LG&E/KU did not establish that the 2021 IRP produced a least cost plan to reliably serve its projected load."[19]

As compared to the 2021 IRP, the Companies' current plan is a marked improvement on its prior iteration, yet suffers from many of the same critical flaws. For example, the Companies' 2021 IRP unreasonably assumed zero incremental savings from their DSM-EE programs after the end of the then-approved planning period in 2025, choosing instead to ignore savings potentials despite anticipated near-term capacity needs. In their 2024 IRP, the Companies again do not evaluate the potential of additional cost-effective efficiency measures, and instead rely on existing and planned DSM resources. Similarly, Staff instructed the Companies to more fully account for the uncertain possibility of carbon regulation going forward, a noted absence yet again.[20]

Most improved from the previous IRP, however, the Companies do appear to at least intend to implement the 2024 IRP. The Commission noted of the previous IRP:

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[19] Case No. 2021-00393, Order, Appendix *Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Elec. Company and Ky. Util. Co*., at p.66-67 (Sept. 16, 2022) ("Staff's Report on 2021 IRP").

[20] *Id.* at 59-61; *see also* Attach. JI-1, AEC White Paper at 28.

> Although LG&E/KU provided a significant amount of useful information that will help in assessing future proposed generation acquisitions, the 2021 IRP, like the IRPs of some other utilities, was conducted more as a planning exercise with the understanding that the plan proposed will not likely be implemented. Commission Staff believes that this resulted in an IRP plan that is not consistent with LG&E/KU's actual expectations and is less rigorous than required by the IRP regulation.[21]

Here, as discussed below and in the attached AEC White Paper, Companies do appear to present a recommended portfolio they intend to pursue. The problem is that it seems to remain detached from the actual modeling and resource planning exercises they continue to go through the motions of presenting.

As Staff explained in 2021: "given the energy transition that is expected in the coming decades, Commission Staff believes that the need to holistically review utilities' actual long-term resource acquisition plans is more important than ever."[22] Despite Staff and Intervenors' comprehensive recommendations in the 2021 IRP, LG&E/KU again fail to meaningfully improve upon their resource planning and decision-making. Joint Intervenors offered detailed recommendations on how the Companies' process, methodology, resource assumptions, and documentation could be materially improved in subsequent IRP filings.[23] Yet, as pointed out in AEC's White Paper, the Companies continue to ignore both intervenor recommendations and clear Staff directives to the detriment of their IRP.[24]

d. Policy landscape & developments

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[21] *Id.* at 63-64.

[22] *Id*. at 65.

[23] Case No. 2021-00393, *Joint Intervenors' Initial Comments on Louisville Gas and Elec. Company and Ky. Util. Co.'s Joint 2021 Integrated Resource Plan*, at 6-7 (April 22, 2022) ("JI Initial Comments on 2021 IRP").

[24] *See* Attach. JI-1, AEC White Paper at 14-15, 17, 22, 25, 27-28, 37.

There have been significant shifts in the policy landscape in the intervening three years since the Companies' last IRP at both the state and federal level, as well as the Companies' portfolio that are touched on in these comments and the attached AEC White Paper. In brief, the state legislature has adopted two new laws governing the retirement of fossil fuel-fired electric generating units, the US EPA has adopted a suite of new rules to mitigate health, climate, and environmental damage from power plants, and the Company has undertaken construction of a new natural gas combined cycle unit (NGCC) that will lead to the retirement of two coal-fired units.

In 2023 the Legislature adopted a new law which now requires Commission approval of retirement of fossil fuel-fired units for the first time, and creates a rebuttable presumption against retirement, unless certain requirements are met, including that the retiring unit will be replaced with new capacity meeting certain qualifications, that the retirement will not harm ratepayers, and that the decision to retire the unit was not the result of Federal incentives.[25]

The Companies were the first, and so far only, utilities to apply under that law, requesting permission to retire Mill Creek Units 1 & 2, Brown 3, and Ghent 2 shortly after adoption of the law.[26] The Commission subsequently consolidated that case with an already-pending application[27] for certificates of public convenience and necessity (CPCNs) for construction of two NGCCs, one at the Companies' Mill Creek Station, the

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[25] Ky. Gen. Assembly Senate Bill (SB) 4, *An Act Relating to the Retirement of Fossil Fuel-fired Electric Generating Units and Declaring an Emergency* (2023); *see also* Attach, J-1, AEC White Paper at 5-6 for further discussion of the requirements.

[26] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Fossil Fuel-Fired Generating Unit Retirements*.

[27] Case No. 2022-00402, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan* Order (May 16, 2023).

other at the Companies' Brown Station, as well as two solar facilities and a battery energy storage system (BESS), and various purchase power agreements (PPAs) related to various solar installations.[28] That application was partially approved, with the retirement and construction of the Mill Creek units granted and the other fossil fuel retirements and construction denied. The solar and BESS CPCNs and PPAs were also approved.[29]

After this initial test of the 2023 law, the legislature further expanded the restrictions on retirement of fossil fuel-fired units in 2024. The adoption of SB 349 over the veto of the Governor created a new Energy Planning and Inventory Commission (EPIC), to which utilities are now required to submit notice, and receive findings from, prior to applying to the Commission for permission to retire fossil fuel units.[30] SB 349 also added further restrictions on the types of generating sources that could replace fossil units by defining "dispatchable" to exclude "intermittent" resources, including solar, wind, geothermal, biomass, anaerobic digestion, short-duration energy storage, or any combination thereof.[31]

At the federal level, US EPA adopted a set of four rules specifically aimed at the impacts of electric generating units in early 2024:

- **Greenhouse Gas (GHG) Rule**. Adopted new source performance standards ("NSPS") for new gas combustion turbines under Clean Air Act ("CAA") section 111(b) and emissions guidelines for existing steam generators under CAA 111(d). Emissions limits are set based on the "Best System of Emissions Reductions" ("BSER"), which was determined to be carbon capture and

[28] Case No. 2022-00402, Joint Application at 1-2 (Dec. 15, 2022).

[29] Case No. 2022-00402, Order (Nov, 06, 2023); *rehearing granted on other grounds by* Order (Dec. 07, 2023).

[30] Ky. Gen. Assembly SB349, *An Act Relating to Energy Policy and Declaring an Emergency* (2024).

[31] *Id.* at Section 1(2)(b) & (d).

sequestration ("CCS") for all baseload units.[32] The rule's requirements and timelines are summarized by the EPA fact sheet "BSER At-A-Glance."[33] The US Supreme Court issued an interim decision in October 2024 that allows the rule to stay in place as litigation proceeds.[34]

- **Mercury Air Toxics Standard (MATS) update.** Most importantly, the update lowers the limit for particulate matter ("PM" - as a surrogate to be measured for heavy metals) from 0.030 lb/MMBtu to 0.010 lb/MMBtu.[35]
- **Coal Combustion Residuals (CCR) update.** Adds requirements for CCR at "legacy CCR impoundments" at closed units and CCR "management units" (CCRMUs) on land outside of regulated CCR units.[36]
- **Effluent Limitations Guidelines (ELG) update**. Also updated in early 2024, the ELG update set a "zero discharge of pollutants limitation" ("ZLD") for flue gas desulfurization ("FGD") wastewater, bottom ash transport water ("BATW") and combustion residual leachate ("CRL") for coal-fired power plants.[37]

EPA additionally adopted two other new regulations of note not aimed specifically at electric generating units:

- **Good Neighbor Plan/Rule for the 2015 Ozone NAAQS.** A "Federal Implementation Plan" (FIP) covering 23 states for which EPA determined state plans (SIPs) to limit downwind impacts of ozone precursor emissions were insufficient. For purposes of power plants, the rule establishes budgets and a trading program for nitrogen oxides ("NO_X") emissions, but would essentially require installation and operation of selective catalytic reduction ("SCR") on all units (or impose significant and expensive allowance surrender for going over

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[32] EPA, New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 09, 2024).

[33] https://www.epa.gov/system/files/documents/2024-04/ cps-table-of-all-bser-final-rule-4-24-2024.pdf

[34] *West Virginia v. EPA*, 220 L.Ed.2d 162 (U.S. 2024)

[35] EPA, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508

[36] EPA, Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 08, 2024).

[37] EPA, Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40,198 (May 09, 2024).

daily rates).[38] The 6th Circuit vacated the disapproval of Kentucky's SIP,[39] and the Supreme Court stayed the FIP in 2024.[40]

- **Fine Particulate Matter ($PM_{2.5}$) National Ambient Air Quality Standards (NAAQS).** The standard was lowered from an annual average of 12 to 9 µg/m^3, requiring EPA evaluation and designation of areas across the country as attainment or nonattainment, and additional measure in nonattainment areas to improve air quality.[41]

3. Load forecast

The Companies' 2024 IRP would have benefited from a more robust evaluation of load forecast scenarios, and greater clarity and transparency in terms of how various load forecast assumptions influence system needs, portfolio options, costs and risks. Instead, the load forecasting approach suffers from a variety of shortcomings, discussed in detail in the AEC White Paper, Attach. JI-1: (A.1) inadequate support for forecasted residential customer growth and increases in demand from large commercial customers; (A.2) not evaluating sensitivities with expanded demand-side management resources; (A.3) not evaluating sensitivities with more rapid behind-the-meter solar with increased rates or attempting to forecast residential or commercial battery storage adoption rates; (A.4). unclear justification and data support for new electrification load from electric vehicles and heating; and (A.5) inadequate support and documentation for high expectations of data center load.

Here, Joint intervenors provide additional comment regarding (a) indications that the 2024 IRP does not adequately or reasonably assess potential large data center customer growth; and (b) the shortage of sensitivities that test potentially cost-effective

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[38] EPA, Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (Jun. 05, 2023).

[39] *Kentucky v. EPA*, 123 F.4th 447 (6th Cir. 2024)

[40] *Ohio v. EPA*, 603 U.S. 279 (2024)

[41] EPA, Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 89 Fed. Reg. 16,202 (Mar. 06, 2024).

and low-risk demand-side potential and realisting engagement with possible DSM and distributed generation possibilities.

a. Companies must develop and evaluate a complete range of future demand possibilities.

The Companies' 2024 IRP begins with a significantly changed load forecast. As compared to the forecast presented in the 2021 IRP, this IRP forecasts 31.7% higher energy requirements, a nearly 1,400 MW increase in winter peak demand, and a roughly 1,100 MW increase in summer peak demand.[42] With this optimistic view of future energy and demand growth, the IRP prefigures major new resource investment needs. The IRP does not, however, fully explore the implications of a reasonable range of future forecasts, evaluate cost-effectiveness of adopting policies and programs intended to reduce or shift demand, or offer meaningful evaluation of cost-effective demand-side management savings not already in place.

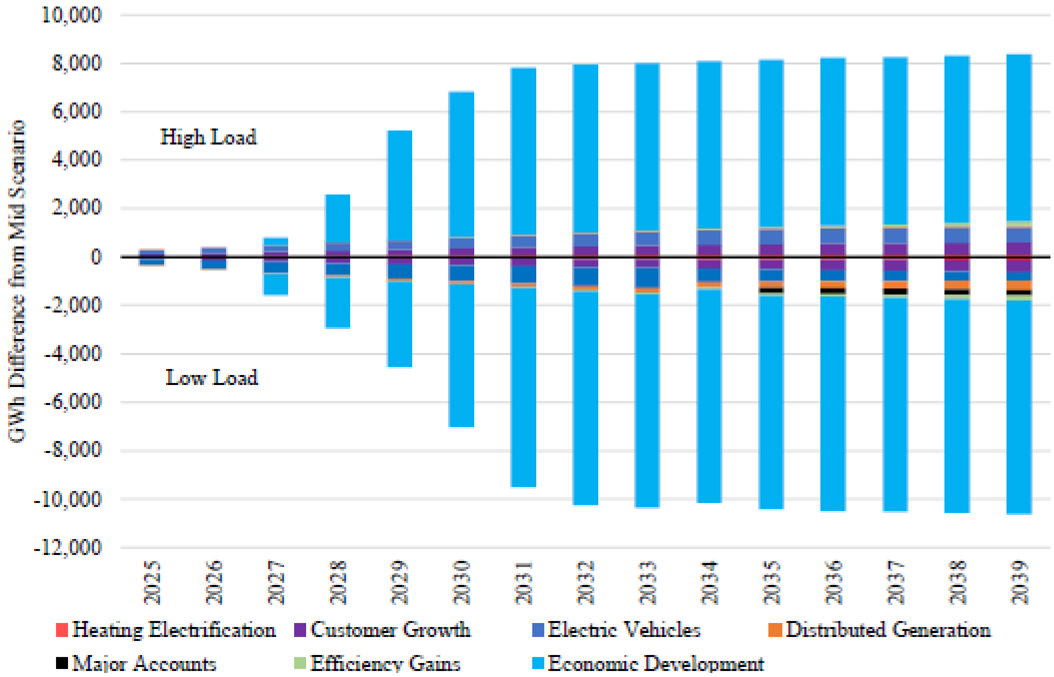
First, data center growth assumptions dwarf every other factor influencing the load forecast, but without adequate justification or risk analysis. The Companies' 2024 IRP depends on a Mid load forecast, and two sensitivities—a low and high forecast—that vary based on a handful of forecast adjustments: EV adoption rates, residential customer growth, energy efficiency gains, distributed generation adoption rates, and electric space heating adoption rates.[43] Forecast adjustments based on assumed large load customer growth is, however, the single most determinative factor distinguishing the load forecasts. The Low sensitivity reflects an absence of data center load growth—consistent with the status quo; the High sensitivity reflects 1,750 MW of new data center

[42] IRP Vol. I at 6-1 to 6-3.
[43] IRP Vol. I at 7-34.

load growth by 2032. The presence/absence of economic development adjustments in these two sensitivities is reflected in the blue bars labeled “Economic Development” in Figure 7-17, reproduced below.

Figure 4

Figure 7-17: High and Low Scenario Energy Requirements Differences (GWh)



As discussed below, these are speculative growth assumptions that pose significant affordability and reliability risks.[44] Despite their high uncertainty and high-risk character, the Mid and High load forecasts are the focus of the 2024 IRP.

Second, despite recognizing that “customer behavior is a key component to robust load forecasting,”[45] and customer adoption of technologies and appliances is largely driven by economics, the load forecast does not appear to evaluate the Companies’ ability to cost-effectively encourage customer adoption of energy saving,

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[44] Section 3.b.
[45] IRP Vol. I at 7-37.

producing, or shifting resources. The Companies' forecasting approach, as with past forecasts, does a relatively passable job of collecting data that could influence future energy demand, but neglects to evaluate the potential for the programs and policies within the Companies' direct control which might influence future energy demand. This practice has continued despite Staff Report recommendations that future IRPs expand evaluation of the economics, incentives, and uncertainties of distributed generation, including but not limited to distributed solar, and the impact of various rate structures on customer energy use and peak demand (e.g., time of use ratemaking; availability of net metering rates).[46]

In future IRPs, the Companies should undertake rigorous exploration of how matters within their control might influence ratepayer energy usage patterns in a way that reduces overall system costs.

Third, although the Companies' created two forecast sensitivities, the 2024 IRP does very little to consider or even reasonably report on the modeling performed using those sensitivities, as discussed further in the attached AEC White Paper. Because Present Value of Revenue Requirement estimates for the various portfolios modeled are not provided, the 2024 IRP does not inform stakeholders or the Commission of the potential affordability impacts of possible data center load growth. PVRRs were not disclosed except through confidential responses to data requests, so they remain unavailable to the public. Without intervening parties or Commission Staff soliciting this information from the Companies, PVRR values under various load scenarios would not be available at all.

[46] Case No. 2021-00393, Commission Staff's Report on 2021 IRP at 51-52.

b. Significant state and ratepayer risks to overbuilding capacity for data center load that remains largely speculative.

While some focus on data center development should be expected, the 2024 IRP does a poor job of addressing the implications of data center load growth with respect to affordability and reliability risks in particular. From the ratepayer perspective, it is important to get large load forecasting right. The authors of a recent RMI Report focused on the unique challenges of forecasting large loads stated that "[g]ood forecasting is the first line of defense in managing the major risks of systemic forecasting error. Customer affordability is the main risk of over-forecasting, and reliability is the main risk of under-forecasting."[47] The large load forecasting approach used in the 2024 IRP lacks transparency and basis in fact, and forecast results should be viewed with skepticism.

The Mid and High load forecast scenarios modeled in the 2024 IRP assume that data center development disproportionately occurs in the Companies' service territory. As explained by Companies via footnote, the amount of data center load growth assumed in the Mid scenario reflects 4.2% of national data center load growth projected by a recent Newmark study, or 9.4% of EPRI's "Moderate" growth projection. In the HIgh scenario, the assumed data center load growth reflects 7.5% of EPRI's "High" growth project and 4.3% of their Higher growth projections. LG&E-KU's current customers are just 0.6% of all U.S. electric customers. These assumptions are unsupported by the siting of new data center development projects to date, and as noted in the AEC White Paper, the Companies provide no meaningful support for their

[47] Attach. JI-5, Jeffrey Sward, et al., *Get a Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads* at 5, RMI (Feb. 2025).

assumption that LG&E/KU's territory will realize a disproportionate share of national data center load growth going forward.[48]

There is, however, reason to doubt the data center load growth assumptions in the 2024 IRP load forecast scenarios. One, LG&E/KU has not been identified as a "Key U.S. Data Center Market" by the cited Newmark report . Two, the assumed load growth amounts, if realized, would make the LG&E-KU data center market larger than all but one of the identified Key U.S. Data Center Markets.[49] The likelihood of disproportionate growth in LG&E/KU's territory has not improved in Newmark's 2025 U.S. Data Center Market Outlook, which does not identify the territories as part of existing or emerging leading data center markets.

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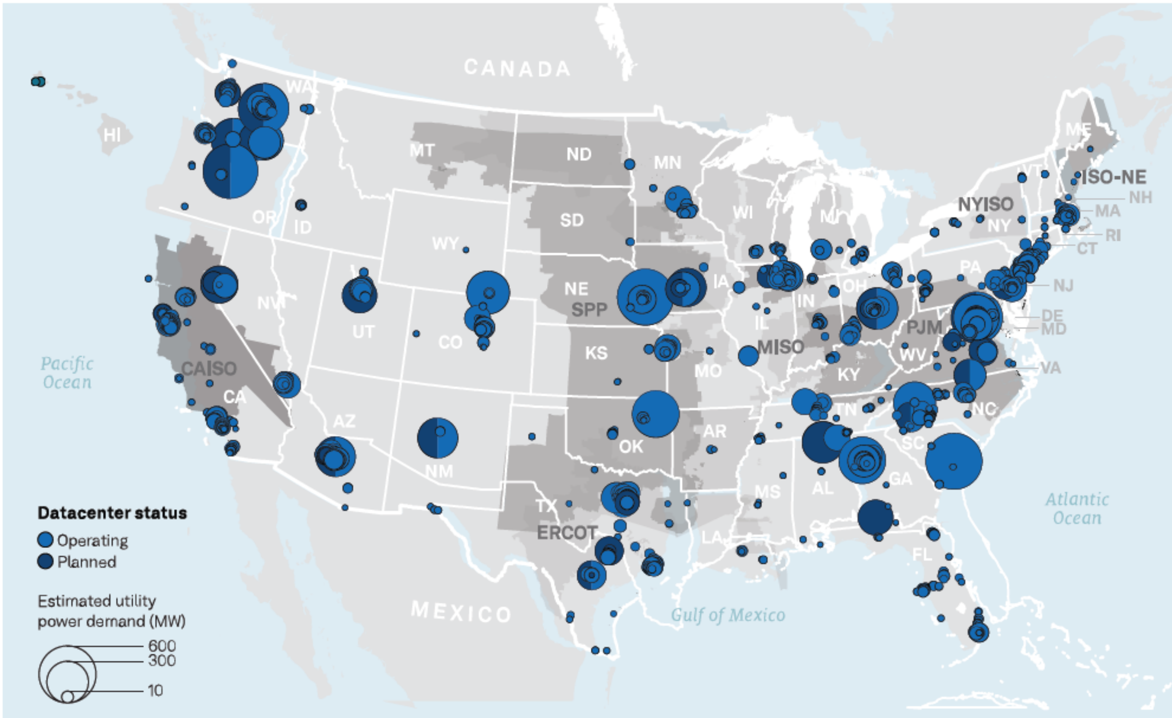
[48] Attach. JI-1, AEC White Paper at A.5 (citing Vol. I at 7-14, n.52).

[49] Newmark at 8-9 (only Northern Virginia market would be larger than LG&E/KU's High load scenario data center assumptions).

Figure 5

Power Demand from Operational and Planned Data Centers



Sources: S&P Global Market Intelligence; 451 Research; S&P Global Commodity Insights

Experience to date and expectations going forward suggest the 2024 IRP plans for excessive data center growth than is likely to materialize within the Companies' service territory.

Basic incentives also support close scrutiny of utility large load forecasts, and there are more generalized reasons to be skeptical of the Companies' load growth projections as well. In a recently released report, Eliza Martin and Ari Peskoe of the Harvard Law School succinctly explain:

> There are reasons, however, to be skeptical of utilities' projections. Utilities have an incentive to provide optimistic projections about potential growth; these announcements are designed in part to grab investors' attention with the promise of new capital spending that will drive future profits. When pressed on their projections, utilities are often reticent to disclose facility-specific details on grounds that a data center's forecasted load is proprietary

information. This secrecy can lead utilities and analysts to double-count a data center that requests service from multiple utilities. To acquire power as quickly as possible, data center companies may be negotiating with several utilities to discover which utility can offer service first. Technological uncertainty further complicates the forecasting challenge. Future innovation may increase or decrease data centers' electricity demand.

Martin and Peskoe's Report, titled *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power*, is provided as Attachment JI-2. This strategy of driving investor interest can be seen in the recent strategy from PPL, announcing large capital expenditures in reports to investors,[50] and in press releases[51] picked up and covered by trade magazines and others.[52]

As Grid Strategies LLC recently noted, "business revenues to cover the costs of the artificial intelligence investments have not yet been proven," and the "combination of exuberance and uncertainty raises the question of whether these projects could fail to sustain anticipated power demand."[53] The speculative character of some growth

[50] Attach. JI-2, 2024 Q4 Investor Update at 23.

[51] LG&E-KU, LG&E and KU forecast load growth due to data centers and economic development, https://lge-ku.com/newsroom/press-releases/2024/10/18/lge-and-ku-forecast-load-growth-due-data-centers-and-economic; LG&E-KU, LG&E and KU power Kentucky's growth with plans for new generation and battery storage, https://lge-ku.com/newsroom/press-releases/2025/02/28/lge-and-ku-power-kentuckys-growth-plans-new-generation-and.

[52] *See*, *.e.g.*, Sonal Patel, LG&E, KU Propose $3.7B Power Buildout: 1.3 GW of New Gas Plants, $153M Coal Unit Upgrade, POWER (Mar. 04, 2025), https://www.powermag.com/lge-ku-propose-3-7b-power-buildout-1-3-gw-of-new-gas-plants-153m-coal-unit-upgrade/; David A. Mann, LG&E proposing $3.7 billion in upgrades, cites economic development, Louisville Business First (Mar. 04, 2025), https://www.bizjournals.com/louisville/news/2025/03/04/lg-e-considering-3-7-billion-in-upgrades.html; Ethan Howland, PPL's Kentucky utilities propose 1.3 GW of gas, 400 MW of storage to meet data center load, UtilityDive (Mar. 03, 2025), https://www.utilitydive.com/news/ppl-kentucky-psc-ku-gas-storage-data-center/741351/; The Lane Report, LG&E-KU ask to add 1,300 MW of generation, 400 MW of battery, (Mar. 03, 2025), https://www.lanereport.com/179657/2025/03/lge-ku-ask-to-add-1300-mw-of-generation-400-mw-of-battery/.

[53] John D. Wilson, et. al., Grid Strategies, *Strategic Industries Surging: Driving US Power Demand* (Dec. 2024) at 21, https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf; *see also* Allison Nathan,et. al., *Gen AI: Too Much Spend, Too Little Benefit?*, Goldman Sachs Global MacroResearch, Issue 129 (June 25, 2024), https://www.goldmansachs.com/images/migrated/insights/pages/gs-research/gen-ai--too-much-spend%2C-too-little-benefit-/TOM_AI%202.0_ForRedaction.pdf.

projections may be coming into focus. Recently, Microsoft canceled leases with multiple private data-center operators that would have had “a couple of hundred megawatts” of load.[54] “This is not the first time the U.S. power system has experienced this magnitude of demand growth, and we can learn from the past to make proactive decisions.”[55]

Finally, the state of inquiries for and development of data centers in the Companies’ service territory also invites skepticism about whether the Companies’ optimistic growth forecasts will be realized. The process for potential interconnection of new large load customers lacks transparency, making it impossible for stakeholders or regulators to ascertain the amount of development that may actually be realized, and the single project confirmed for LG&E’s territory is a speculative development by real estate investors that does not yet have any committed tenants.[56]

With respect to process, the Companies explain that, when a potential data center customer comes to the Companies for possible service, a project manager will assign “stages, or phases, according to the level of activity (communication, information exchange, due diligence, etc.)” between the potential customer and the Companies, the state, or the local community.[57] From lowest to highest, those stages are “inquiry, suspect, prospect, imminent and announced.” The current status of the total number of projects disclosed by the Companies is detailed in the table below.

STAGE	DESCRIPTION	Nov. 25, 2024[58]	Jan 26, 2025[59]

[54] https://www.reuters.com/technology/ microsoft-shelves-ai-data-center-deals-sign-potential-oversupply-analyst-says-2025-02-24/

[55] Attach. JI-4, Energy+Environmental Economics, Load Growth Is Here to Stay, But are Data Centers?: Strategically Managing the Challenges and Opportunities of Load Growth (July 2024) at 3.

[56] Companies’ Resp. to JI 2.25.a.

[57] Companies’ Resp. to JI 1.16.c.

[58] Companies’ Resp. to JI 1.16.d.

[59] Companies’ Resp. to JI 2.16(a-d), Attachment

Inquiry	High level information exchange, possibly a few meetings	7	7
Suspect	Some likelihood of continued information exchange and verge of more formal process	1	3
Prospect	Very regular information exchange, more detailed evaluation of infrastructure and costs, site visits, incentive negotiation	7	7
Imminent	High probability project will locate in territory, developer has all information necessary to make decision	1	1
Announced	Developer formally announced	0	0

Without more detailed information including the interested party and visibility into where else in the state, country, or world a potential new customer has inquired or communicated with a utility as to energy prices, it is impossible to reasonably judge the likelihood that any given project may advance to the announced stage, much less actually get built and take the full amount of originally expected power.

With limited visibility into the data center growth projections, the projections should be scrutinized closely by regulators.

c. *The significant potential of behind the meter alternatives remains to be adequately analyzed, let alone realized.*

The Companies acknowledge in passing several times the influence their own decisions may have on projected load growth, but fail to seriously grapple with the alternatives and present an actual summary of LG&E-KU's plans or steps to be taken.[60] Given the significant load growth projections discussed above, the Companies should have at least seriously evaluated the possibility of mitigating or offsetting load growth through implementation of cost-effective measures. The following categories for potential consideration are discussed further below: expanded demand-side management/energy-efficiency (DSM-EE) resources; behind-the-meter solar and distributed generation; and demand response/curtailable service riders (DR/CSR).

First, as pointed out in the attached AEC Report, the Companies failed to evaluate sensitivity of the recommended plan to lower potential loads as a result of demand-side measures leading to lower load, and therefore shows a greater need for new supply resources. Instead, the Companies modeling assumes the end of essentially all demand side management offerings in 2030, just as load is nearing its projected peak.[61] The Companies' did not evaluate as part of the 2024 IRP "more aggressive options to increase use of the curtailable service rider and demand conservation program" despite the Staff Report's recommendation to do so.[62] Further investment in energy efficiency and demand response measures could result in lower bills, and be of particular help if targeted at the communities struggling most to keep the lights and heat on.

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[60] 807 KAR 5:058 Section 5.: "The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum: … (4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, ***demand-side programs, nonutility sources of generation,*** new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities; (5) Steps to be taken during the next three (3) years to implement the plan; …." (emphasis added).

[61] Attach. JI-1, AEC White Paper at 15.

[62] Staff's Report on 2021 IRP at 68; *see also* AEC Report at 15.

Second, the possibility of significant additional distributed generation growth is at least seriously contemplated, but the Companies' projections remain conservative related to the growth seen in recent years. Figures 6 and 7 below, copied from Volume I of the IRP, juxtapose to-date growth in net metering capacity, and projected future distributed generation:

Figure 6 - Cumulative Net Metering Customer and Capacity Adoption. IRP Vol. I at 7-21, Figure 7-4.

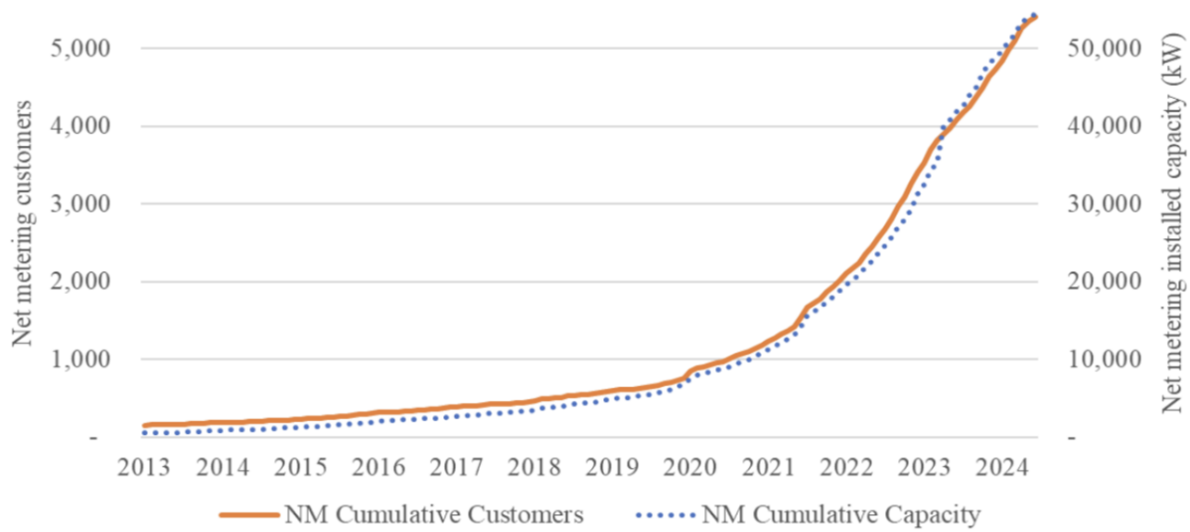
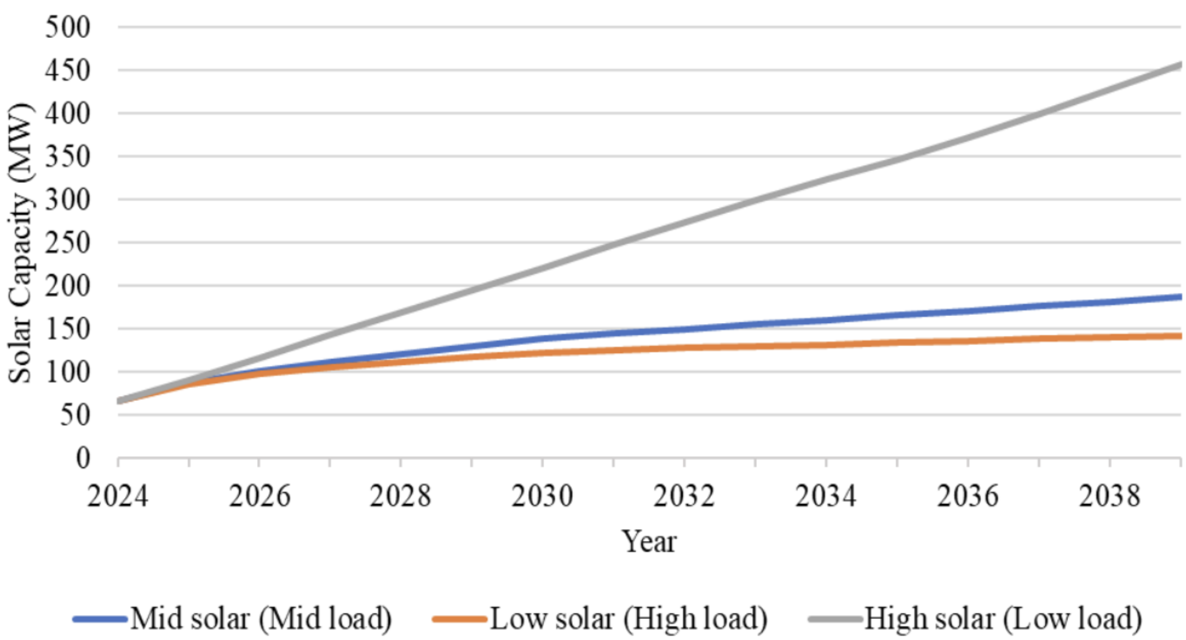


Figure 7 - Distributed Generation Forecast Scenarios. IRP Vol I. at 7-22, Figure 7-5.



The difference between the High solar and Mid and Low solar forecasts, according to the Companies, is dependent on whether they continue to offer net metering for eligible customer-generators beyond 1% of their previous year's peak load, as allowed by statute - in other words, the difference is dependent on whether the Companies maintain the status quo, or reduce compensation for distributed generation resources.[63] However, this being the case, one would expect to see the High solar scenario much closer to the growth seen in recent years, including after the Companies' previous change in compensation methodology for net metering customers in 2021.[64] This would especially be expected in the short term, as opposed to a sudden flattening in growth. The Companies rightly point out that the current rate of growth of solar distributed generation cannot continue unabated through the entire forecast period.[65] However, while the Companies argue that Kentucky cannot meet the levels of solar penetration seen in California or Arizona,[66] other states with much less favorable natural conditions also see greater penetration. Vermont, with a total population roughly equivalent to half the Companies' combined number of ratepayers[67] currently has 106 MW of installed residential net metering capacity,[68] roughly double that of the combined cumulative

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[63] IRP Vol. I at 7-22.

[64] *See* Case Nos. 2020-00349 and 2020-00350, Final Order (Sep. 24, 2021) and Order on Rehearing (Nov. 04, 2021), generally. For a more thorough explanation in the change in methodology and history of these cases, see the Memorandum Brief of Joint Intervenors Kentucky Solar Energy Society and Kentuckians for the Commonwealth at 30-46 (Jun. 26, 2024) in Case No. 2023-00413, Electronic Application of Duke Energy Kentucky, Inc. For an Adjustment to Rider NM Rates and for Tariff Approval.

[65] Companies' Response to JI 1-76.d.

[66] IRP, Vol. I at 7-27.

[67] Compare US Census Data for 2020 at http://data.census.gov/table/DECENNIALCD1182020.P1?q=population+of+vermont with IRP, Vol. I at 5-1.

[68] Annual Electric Power Industry Report, Form EIA-861 detailed data files (2023), https://www.eia.gov/electricity/data/eia861/. *See also* Companies' Response to JI 1.77., indicating an adoption rate double that for Kentucky.

capacity of LG&E-KU solar, showing there is certainly potential for much higher penetration.[69]

In testimony in case no. 2022-00402, Joint Intervenors specifically addressed several means by which the Companies' could proactively develop distributed energy resources on their system to cost-effectively reduce the need for supply side resources, reduce risk, and improve affordability and reliability. As was previously demonstrated in that case, distributed solar resources, if allowed to grow at the historic growth rate seen over the preceding decade, could provide over 1,000 MW of solar capacity by 2030. Likewise, based on the experience of utilities in other states, distributed battery storage programs have the potential to provide hundreds of MW of reliable, dispatchable capacity. Each of these distributed energy resources have the advantage of being deployable rapidly, with reduced execution risk, and flexibly, affording the ability to adjust deployment as load requirements become more clear. They can also provide additional value to support distribution grid infrastructure, deferring investments for equipment replacement.

To the extent that this is the result of incentives and return on investment or payback period for installations,[70] the Companies' fail to acknowledge that it is them that controls these factors, and to seriously evaluate the cost-effectiveness of alternatives. For instance, the decision of whether to end net metering once capacity reaches 1% of peak load is entirely up to the Companies, yet there's no evaluation of the cost-effectiveness of the alternatives. The Company continues to fail to evaluate additional

[69] Companies' Response to JI 1.76.a.
[70] Companies Response to JI 1.77.

incentives offered by other utilities, such as those previously pointed to by the Joint Intervenors in previous testimony.[71]

Finally, the Companies fail to address the possibility of new large load additions participating in demand response or curtailable service ride programs, potentially allowing a significant shaving of the peaks currently projected from these sources. In response to questions about the potential for curtailable service provisions for data centers or on-site battery energy storage systems (BESS), the Companies claim there is "[n]one,"[72] and stated in response to a separate question that

> [t]he Companies have primarily been responding to requests for infrastructure and capacity from potential customers needing around the clock energy, every day of the year. Those potential customers have not asked about or expressed interest to the Companies concerning curtailable service, standby on-site generation, behind the meter generation, participation in energy efficiency programs, or any other approaches to offset needed capacity.[73]

They fail, however, to address whether they have made any effort at encouraging adoption of such measures to mitigate the projected growth in demand. As discussed in the attached report from the American Center for an Energy Efficient Economy (ACEEE), with proper incentives data center could be "grid assets," shifting computational loads to off-peak periods, at the same time "providing ancillary services…and improving utilization of grid infrastructure…."[74] This requires at a

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[71] *See* Case No. 2022-00402, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Tendered Corrected Testimony of Andrew McDonald on Behalf of Joint Intervenors Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society and Mountain Association at 27-30 (Jul. 24, 2023) in .

[72] Companies' Response to JI 1-49.d.-e.

[73] Companies' Response to Sierra Club 1-12.e.

[74] Attach. JI-10, Nora Wang Esram and Neal Elliott, ACEEE Policy Brief, *Turning Data Centers into Grid and Regional Assets: Considerations and Recommendations for the Federal Government, State Policymakers, and Utility Regulators* (Oct. 2024)

minimum further collaboration between utilities and data centers, but also policy-makers such as the Commission, and the public.[75] Options for flexibility and grid support likely exist,

> However, without proper incentives, data center owners, operators, and even their customers have little reason to pursue these opportunities, resulting in a failure to take advantage of data centers' full potential of demand flexibility. Realizing this potential relies on the collaborative efforts of technology developers and providers, utilities, and governments—all supported by corresponding industrial standards and regulatory frameworks.[76]

d. Companies should use this opportunity to ensure protections for current ratepayers.

Joint Intervenors express skepticism at the scale of projected load growth in the Companies' Mid and High Scenarios, and urge caution in planning around those scenarios until more firm justification is provided. The Companies owe an obligation to current ratepayers, as well as policymakers such as the Commission, and the public at large, to be as transparent as possible. At the same time, they must ensure that unjustified load projections don't result in over-investment that ends up falling on their backs. Aside from more firm justification, this should include review and potential adoption of tariff amendments as recommended in the attached report from Energy Futures Group.[77]

The Companies also can and should take proactive steps to support the deployment of demand-side and distributed energy resources, at the pace and scale needed to meaningfully help supply customer needs. These steps include:

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[75] *Id.* at 8-9.

[76] *Id.* at 7.

[77] Attach. JI-6, Stacy Sherwood, Energy Futures Group, *Review of Large Load Tariffs to Identify Safeguards and Protections for Existing Ratepayers* (Jan. 28, 2025)

- Continue offering net metering beyond the minimum 1% threshold.[78] The Companies note in their 2024 IRP that imposition of this cap on net metering would significantly depress deployment of distributed solar energy systems. As the option to impose this cap is entirely at the Companies' discretion, they should proactively and publicly announce that net metering will continue to be offered beyond the 1% threshold, providing greater certainty to the solar market and enabling the ongoing growth of this valuable utility resource
- Allow virtual net metering, to enable the transfer of credits generated by a solar PV array to other customer accounts on the Companies' system. This would make solar PV accessible to many more customers and at more locations. For example, an apartment building could transfer credits to its residents from a single array on the roof.[79]
- Develop evaluation of distributed energy resource rebate and demand response programs; utilizing customer-sited batteries with realistic yet ambitious deployments targets. The 2024 IRP notes the Company has begun to assess offering a BYOB (Bring Your Own Battery) demand response program, but its deployment targets are exceedingly modest. The IRP projects peak demand savings from battery storage of 0.97 MW by 2030 and 1.77 MW by 2035. Contrast this with Massachusetts, which as of 2020 had installed 286 MW of customer-sited batteries within 2 years of program implementation or Green

[78] McDonald CPCN Testimony at 7-8.
[79] McDonald CPCN Testimony at 18.

Mountain Power in Vermont, which had 2,500 customers participating in its BYOB program as of 2023.

- Evaluate the use of Virtual Power Plants, actively controlled distributed energy resources, to provide multiple system benefits. VPP's can be composed of many distributed technologies, including but not limited to smart thermostats, smart water heaters, batteries, and electric vehicles.
- Evaluate the use of rebates or other incentives to promote distributed energy resources, including demand response.
- Evaluate potential impacts of off-peak EV charging rates;
- R reopening or creation of new curtailable service rider, large-load demand response, andor direct load control programs; and development of
- Consider further development of time of use rates.

4. Resource Assessment and Acquisition Plan

The attached AEC White Paper offers an expert review of the Companies Resource Assessment and the paucity of information to support the Recommended Resource Plan advanced in the 2024 IRP. Joint Intervenors expand upon three of those issues here.

a. The 2024 IRP does not attempt to evaluate the impact of expanded demand-side management programs on least-cost portfolios.

Although the 2024 IRP did assume that currently approved DSM-EE programs would continue through the planning period,[80] the Companies did not evaluate increased energy or demand savings on par with new supply-side resource investments. Instead, the load forecast incorporated a single set of DSM-EE program

[80] IRP Vol. I at 8-21.

impacts for all portfolio modeling. The Companies' appear to justify this approach to DSM-EE evaluation in the IRP based on the 2023 approval of its current DSM-EE Plan, but this hardly justifies ignoring the potential for increased DSM-EE savings. Just as 2023 approval of a gas plant didn't obviate the need for continued supply-side resources, approval of existing DSM-EE programs doesn't obviate the need to optimize cost-effective DSM-EE potential.

In advance of the Companies' last significant proposal to build new supply-side resources just two years ago, the Commission cautioned LG&E/KU to maximize cost-effective demand-side resources before asking for new construction approvals.[81] To the Companies' credit, though absent from the 2021 IRP, the 2022 CPCN application did include expanded cost-effective DSM-EE programs. Since finalizing the 2024 IRP, however, the Companies have proposed over $3.7B in new supply-side investments, and it is not clear that there has been any reevaluation of cost-effective demand-side management potential as part of the IRP[82] or the latest CPCN filing.[83]

In addition to appearing not to have evaluated expanded DSM-EE potential, it is unclear whether the Companies are likely to file any updates to their 2024-2030 DSM-EE Plan. The Companies identify three factors that may inspire a DSM-EE Plan update,

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[81] Case No. 2020- 00349, *Elec. Application of Ky. Util. Co. for an Adjustment of Its Elec. Rates*, Order at 61 (June 30, 2021); Case No. 2018-00348, *Elec. 2018 Joint Integrated Resource Plan of Louisville Gas and Elec. Co. and Ky. Util. Co*., Order at 22–23 (July 20, 2020), https://psc.ky.gov/pscscf/2018%20Cases/2018-00348//20200720_PSC_ORDER.pdf.

[82] *See* Attach. JI-1, AEC White Paper at 14-15.

[83] *See*, *e.g.*, Case No, 2025-00045, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Direct Testimony of John Bevington Senior Director, Business and Economic Development on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company at 14 (Feb. 28, 2025).

but none include cost-effectiveness of demand-side resources to mitigate higher costs of supply-side additions:

> Whether the Companies will file updates to their DSM-EE plan depends on 1) customer response and participation in the current programs, 2) possible DSM pilot successes and failures, and 3) the success of economic development efforts related to data centers.[84]

Perhaps that was an oversight, and the Companies would agree that its guidestar remains provision of service through least-risk, least-cost portfolios.[85]

Clearly the capital costs modeled as part of the 2024 IRP and the capital costs disclosed in the Companies' February 28, 2025 CPCN Application in Case No. 2025-00045, will improve the cost-effectiveness of demand-side management potential, warranting re-investigation as part of least-risk, least-cost portfolio planning. It is unreasonable that the Companies' missed the opportunity to evaluate that potential as part of the 2024 IRP process, and that unreasonable IRP approach may have the effect of driving higher supply-side costs.

Based on data responses, in 2024, the Companies sought a DSM-EE potential study addressing Residential, Commercial, and Industrial sectors.[86] Presumably, such a potential study would recalculate avoided cost values used for cost-effectiveness screening and testing. But it is unclear whether or when that updated picture of cost-effective potential would be put to use through expanded and modified programs. Again, DSM-EE potential appears to be an afterthought, pursued after committing customers to billions of dollars in capital projects, if at all.

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[84] Companies' Resp. to JI 1.3.

[85] *E.g.*, Companies' Resp. to JI 1.12.d. ("Having risk management be the primary focus of resource planning is consistent with safe and reliable service, which the Companies have the objective of providing at the lowest reasonable cost.").

[86] Companies' Resp. to JI 1.4.a.

b. To develop a no-regrets portfolio, an IRP needs to evaluate and maximize no-regrets resource potential.

Quite reasonably, the Companies aspire to pursue no-regrets resource decisions and investments. The 2024 IRP succinctly states the reasons why the Recommended Resource Plan is a no-regrets plan, in the Companies' view:

> The Recommended Resource Plan is a "no regrets" resource plan because the accelerated resources are needed by 2035 if high economic load growth or CO_2 regulations do not come to fruition. Furthermore, the addition of 500 MW of solar reflects the likelihood that some level of solar will be least-cost even without CO_2 regulations.[87]

These statements may be true, as far as they go.[88] But the 2024 IRP does very little to evaluate resource alternatives in light of this no-regrets planning aspiration and the particular uncertainties at issue, and ultimately does nothing to test or measure potential regrets of the Recommended Resource Plan in different futures.

The largest driver of risk to customers in the Companies' 2024 long-range resource planning appears to be the prospect of making giant investments to add generation resources to serve new large loads that do not materialize or do not persist over the next 40 years. This risk is endemic among investor-owned utilities at the present moment, and a recent RMI report details the risks and regulatory solutions.[89] RMI's Report distinguishes "least-regret" and "least-cost" capital investments as necessary planning concepts to mitigate large load growth risks to affordability and reliability:

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[87] Vol. I at 5-27.

[88] The Companies also state in response to JI Q1.25a that "[t]o support the potential for high economic growth development load growth and CO2 regulations, the additions of the Ghent 2 SCR and 400 MW of battery storage are accelerated to 2028 [in the Recommended Resource Plan], the addition of the second NGCC is accelerated to 2031, and the retirement of Brown 3 is deferred to 2035."

[89] Attach. JI-5, Jeffrey Sward, et al., RMI, Get a Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads (Feb. 2025).

> Prioritize “least-regrets” capital investments: Determining what constitutes a least-regret investment is a departure for regulators from more traditional least-cost decision-making. **Least-regrets solutions in the face of uncertainty will be fast, affordable, and flexible.** Many underrepresented options in utility portfolios meet these criteria and are focused on leveraging existing infrastructure, including **energy efficiency, VPPs, grid-enhancing technologies, reconductoring, and clean repowering**.[90]

Several of the fast, affordable, and flexible options mentioned were given little to no attention in the 2024 IRP. As utilities already building one new combined cycle gas plant, with a recent application for approval to construct two more, the Companies 2024 IRP ought to have given greater consideration to energy efficiency, development of VPPs, grid-enhancing technologies, and more.

These least-regrets solutions may also be less costly. A recent report by Brattle Group and Lawrence Berkeley National Laboratory notes that VPPs “have the potential to provide the same resource adequacy benefits as conventional resources, at a fraction of the cost.”[91] The report, provided as Attachment JI 1-7, also explains VPPs’ operational benefits and “potential to mitigate other concerns such a lengthy resource interconnection delays and unprecedented uncertainty in load forecasting.”[92]

The Companies’ future planning should more rigorously consider VPP development potential during this period of great load forecast uncertainty. Examples of successful program strategies and lessons learned in VPP development by leading utilities, platforms, and implementers is provided by the Brattle/LBNL Report provided as Attachment JI 1-7, “30 Strategies to Increase VPP Enrollment.” After interviews with

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[90] *Id.* at 35 (emphasis added).

[91] Attach. JI 1-7, Ryan Hledik, et al., Brattle Group, *30 Strategies to Increase VPP Enrollment* at 4 (Dec. 2024).

[92] *Id.* at 11.

fifteen implementers of successful VPP programs, the report ultimately shares key lessons learned with respect to program marketing, enrollment processes, designing incentives, engaging and retaining customers, and leveraging partnerships.[93]

c. Future IRP modeling will benefit from more assessment of portfolio risks in a variety of foreseeable future scenarios.

Relatedly, there is no indication that the Companies' evaluated portfolio performance in different load forecast scenarios. Instead, the IRP worked only in the other direction: developing an optimized portfolio using variations of environmental compliance obligations, load, and fuel forecasts. As the number of portfolios under evaluation narrowed, the Companies did not return to test the performance of their recommended portfolio in the low or high load forecasts. Knowing that all forecasts are off to some degree, testing portfolio performance across many variations allows portfolio selection to be better informed by future uncertainty.

5. Transmission and Distribution Planning

At the conclusion of the Companies' 2022 CPCN proceeding, the Commission clarified its expectations vis a vis transmission in future IRPs:

> [T]he Commission exhorts LG&E/KU to study the value and opportunities that transmission (regional and interregional) and imports provide in their next IRP. In their past IRPs, any serious consideration or discussion of transmission has been notably absent. Further failure to discuss these options in future proceedings may result in the Commission's own investigation into LG&E/KU's processes in this regard.[94]

Responding to that direction, the 2024 IRP provides a new level of Transmission Information, studies the transmission system impacts of generation retirement and

[93] *Id.* at 15.

[94] Case No. 2022-00402, *Elec. Joint Application of Ky. Util. Co. and Louisville Gas and Elec. Co. for Certificates of Pub. Convenience and Necessity and Site Compatibility Certificates and Approval of A Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Order at 95 (Nov. 6, 2023).

replacement scenarios, and summarizes existing firm transmission capacity to import or export power to neighboring regions.

This subpart revisits each aspect of the 2024 IRP's transmission and distribution components, with observations and recommendations.

a. Transmission Information

The Companies provide "Transmission Information" in Volume III of their 2024 IRP, which appears to largely provide information from the Companies' 2016 applications for a base rate increase and certificates of public convenience and necessity (KU Case No. 2016-00370; LG&E Case No. 2016-00371).[95] The Transmission Information section meaningfully improves on the level of transmission detail provided in past IRPs. The section includes timely discussion of major FERC orders affecting transmission interconnection (Order 2023) and interregional transmission planning processes (Order 1920).[96] As reported, pursuant to Order 2023, the Independent Transmission Operator has changed the previous one-by-one generator interconnection study process with a transitional cluster study process that is presently studying all existing generator interconnection requests.[97]

The change to a transitional cluster study process likely diminishes the accuracy of 2024 IRP modeling. The 2024 IRP relies on generic transmission cost assumptions in evaluating supply-side resources, which are out of necessity rough, illustrative planning estimates. Those estimates and modeling assumptions did not attempt to account for potential transmission expenses under cluster-study analysis of transmission needs and

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[95] IRP Vol. III, Transmission Section at 7.
[96] *Id.* at 18.
[97] *Id.* at 18.

project cost allocation. That may be a reasonable or necessary approach given the timing of FERC's orders and their unknown effect in practice. In any event, for planning purposes, the 2024 IRP's transmission cost assumptions could misstate the incremental costs of large generation additions. That might cut in either direction, and hedging downside risk would be prudent.

The Transmission Information section also reports reliability metrics since 2010, and particularly since the 2017-2022 Transmission System Improvement Plan, providing for roughly $537 million in transmission reliability, system integrity and modernization investment.[98] The Companies report that those transmission projects improved reliability and resilience beyond the plan goal of improving the Companies' combined SAIDI by 3 to 6 minutes.[99]

Joint Intervenors appreciate the Companies' efforts to report Transmission Information in the public 2024 IRP. While recognizing that much of the reported information is in fact available to the public through various means, as a practical matter, the information is inaccessible to most. By collecting and summarizing transmission planning and operations details, as well as noting important changes since the last IRP, the 2024 IRP can meet the ideal of being a first-stop for customers, regulators, and stakeholders to understanding the state of play for transmission resources. Joint Intervenors encourage the Companies to continue such efforts in future IRPs.

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[98] *Id.* at 8.
[99] *Id.*

b. Long-Term Firm Transfer Analysis

The Volume III section titled, *Long-Term Firm Transfer Analysis - Impact to the LG&E/KU Transmission System*, most directly responds to the context in which the Commission encouraged the Companies to study the value and opportunity of transmission in this IRP.[100] Although the Commission did not find it appropriate for the Companies' to "depend on unstudied generation imports" in the 2022 CPCN proceeding, there was record evidence showing that LG&E/KU undervalued the contribution of imports from neighboring systems when planning and operating its system.[101] Joint Intervenors appreciate the more serious study of transmission capabilities with respect to firm transport import and export capacities, and offer the following observations.

First, taken at face value, the Long-Term Firm Transfer Analysis shows that the existing transmission system has been built to provide for greater export potential as compared to import potential. In all export scenarios, existing infrastructure is capable of supporting firm transmission exports up to the maximum 1,000 MW transfer volume tested, and to each of MISO, PJM, and TVA.[102] Existing transmission import capacity is less robust: without additional capital investment, the summer transmission import capacity is limited to 300 MW from each of MISO and PJM, and just 100 MW from TVA; and in the winter, existing transmission could support 500 MW import transfer volumes from each of MISO, PJM, and TVA.[103] In broad strokes, the Companies report an

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[100] Case No. 2022-00402, Order at 95 (Nov. 6, 2023).
[101] *See, e.g.*, *Id.* at 37-38
[102] IRP Vol. III, Long-Term Firm Transfer Analysis at 1-2.
[103] *Id.*

export-import capacity imbalance, with a system built to provide firm export capacity up to the maximum tested transfer volume of 1,000 MW, but import only 100 MW to 500 MW.

In practical effect, this export-import capacity imbalance seems to favor LG&E/KU selling power to neighboring regions and to limit capacity to buy power. That imbalance is unhelpful to customers, as it makes it less likely that LG&E/KU would economically import/buy energy from neighboring regions and less likely that there would be ample transmission capacity to import power to LG&E/KU's system in emergencies.

Encouragingly, the study also makes plain that relatively modest investments could increase firm transmission import capacity to all three neighboring regions. For roughly $3 million apiece, LG&E/KU could increase their system's firm transmission import capacity between each of MISO, PJM, and EKPC by 200 MW.[104] An incremental $6.5 million project could further double firm transmission import capacity from MISO, bringing it to the maximum 1000 MW transfer volume tested.[105]

At a time of potentially significant load growth from data centers able to scale more quickly than the country can build new gas plants, investing in transmission capacity that enables greater sharing of existing and near term resources across regions could be particularly valuable. Additionally, while some storms will stretch bulk power system performance across regions, most do not, and in all circumstances,

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[104] Import capacity from MISO and PJM could increase from 300 MW to 500 MW for an estimated $2,812,500 and $3,090,000, respectively. *Id.* at 2. Import capacity from TVA could be increased from 100 MW to 300 MW for an estimated $2,812,500. *Id.*

[105] *Id.*

greater import potential from broader geographic regions is an effective hedge against the uncertainties of the weather and bulk power system reliability.

c. Generation Replacement & Retirement Scenarios - Impact to the LG&E/KU Transmission System

Volume III also includes an analysis of transmission system impacts in certain generation retirement and replacement scenarios, titled *Generation Replacement & Retirement Scenarios - Impact to the LG&E/KU Transmission System*. Using seven distinct generation retirement scenarios and seventeen variations on when each retired unit is replaced with a generic NGCC, the study largely shows that retiring coal units can be replaced with a new gas plant at the same site for marginal to no transmission system network upgrade costs. Joint Intervenors offer two observations.

One, if taken at face value, this study helps quantify the Companies' competitive advantage in developing new utility-scale generation units in their service territory as the entity that owns and controls existing generator interconnection locations.

Two, the near-term planning value of this study is quite limited. Every scenario tested a generic combined cycle generation replacement—no alternatives were evaluated, not even in distant years, e.g., 2045 and 2066 retirements of Trimble County 1 and 2, respectively. The study results would have been more informative had the Companies explored some variety in potential alternative replacement technologies. Additionally, the study results would have been more informative with more robust evaluation of potential retirements within the next ten years.. The number of variables and unknowns when modeling the much later years makes those conclusions less reliable. Meanwhile, retirement potential in the next five to ten years warrants robust evaluation so that the Companies might make more prudent and informed judgments about the transmission system implications of various retirement and replacement options.

On the whole, the offered Generation Retirement & Replacement Scenarios study disappoints.

d. Distribution Planning Deserves Greater Attention in IRPs, too.

Discussion of distribution resources and efficiencies appears limited to four pages of Volume I, 8-9 to 8-12. In those pages, the 2024 IRP explains that the Companies develop annual and long-term distribution system plans, which are necessarily becoming more complex in light of "[e]volving customer expectations, acceleration of behind-the-meter distributed energy resources ("DER"), advancement in behind-the-meter technologies, and increased system threats[.]"[106] The Companies explain that sustained low load growth thanks to energy efficiency improvements translated into waning capacity needs, and allowed greater "focus on system reliability, resiliency, and aging infrastructure replacement investments."[107] As a result of an emphasis in recent years on "[p]rojects that improve reliability performance of poorer performing circuits and mitigate the effects of major equipment failure,"[108] the Companies have improved reliability metrics.[109]

The distribution planning discussion continues to summarize specific use-cases for Advanced Metering Infrastructure that will be fully deployed by 2026, highlight the increasing share of customer outages resulting from extreme weather, explain management of wildfire risk, and describe the long-standing Pole Inspection and

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[106] IRP Vol. I at 8-9.
[107] *Id.* at 8-10.
[108] *Id.*.
[109] *Id.* at 8-9.

Treatment Program. Finally, the distribution planning discussion turns to planning for grid modernization and supporting greater integration of distributed energy resources.

Joint Intervenors appreciate the inclusion of these discussions in the 2024 IRP, and would encourage continued and improved reporting and practical planning-level evaluations of distribution efficiencies in the next IRP. More robust integration of distribution system efficiencies into IRP planning is necessary to maintain and improve affordability. According to the Edison Electric Institute, "U.S. investor-owned utilities spent an estimated $59.7B on electric distribution system investments in 2024, accounting for the largest portion of capital expenditures" at 32 percent.[110] In addition to being substantial, thoughtful investment in distribution grid resources is needed "to integrate DERs and electric (EVs), facilitate grid services by customers and DER aggregators, maintain reliability and resilience in the face of increasing threats, and improve grid flexibility[.]"[111]

Although LBNL catalogs Kentucky as a state without requirements for Electric Distribution System Planning,[112] the IRP regulation does require description and discussion of "all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing . . . distribution facilities…"[113] As acknowledged, the 2024 IRP does offer discussion of material distribution planning information, and future IRPs would benefit from additional data reporting.

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[110] Attach. JI-8, Sean Murphy, et. al., Lawrence Berkeley National Laboratory, *Bridging the Gap on Data and Analysis for Distribution System Planning: Information that utilities can provide regulators, state energy offices and other stakeholders* (Jan. 2025) ("Bridging the Gap").

[111] *Id.* at 9.

[112] LBNL, State Distribution Planning Requirements webpage, Interactive Map, available at https://emp.lbl.gov/state-distribution-planning-requirements.

[113] 807 KAR 5:058 Sec. 8(2)(a).

By way of example, Joint Intervenors provide as Attachment JI-8, a recent report by LBNL's Energy Markets & Policy group, titled *Bridging the Gap on Data and Analysis for Distribution System Planning: Information that utilities can provide regulators, state energy offices and other stakeholders*. The LBNL Report addresses eleven distribution system planning topics:

1. Forecasting loads and distributed energy resources
2. Scenario analysis
3. Worst-performing circuits
4. Asset management strategy
5. Hosting capacity analysis
6. Value of distributed energy resources
7. Grid needs assessment
8. Cost-effectiveness evaluation for investments
9. Distribution system investment strategy and implementation
10. Geotargeted programs
11. Non-wires alternatives procurement.[114]

The 2024 IRP provides some information on some of these planning topics, and the Companies have provided more detail via data responses. For example, with respect to worst performing circuits, the 2024 IRP reports the use of advanced data analytics to prioritize distribution investment.[115] The Companies also explain the use of

[114] *Bridging the Gap* at 1.
[115] IRP, Vol. I, at 8-10.

risk models to evaluate circuit-level criteria including IEEE 1366 reliability indices,[116] mileage, conductor type and age, vegetation exposure, weather, historical reliability performance.[117]

In response to data requests, the Companies also identified their ten best and worst performing circuits based on 3-year average Customer Minutes Interrupted (2021-2023), and noted that 128 circuits have not experienced an outage in the last three years.[118] The identified worst performing circuits for each utility is reproduced below, with highlights designating where planned reliability investments are expected in 2025.

Utility	Op Center	Substation	Circuit
LGE	EOC	BRECKENRIDGE	BR1185
LGE	EOC	HURSTBOURNE	HB1148
LGE	AOC	SOUTH PARK	SP1116
LGE	EOC	BRECKENRIDGE	BR1186
LGE	EOC	FAIRMOUNT	FM1257
LGE	EOC	WATTERSON	WT1210
LGE	AOC	MANSLICK	MK1296
LGE	EOC	LYNDON	LY1111
LGE	EOC	OXMOOR	OX1274
LGE	AOC	CANAL	CA1346

Utility	Op Center	Substation	Circuit

[116] IEEE 1366 reliability indices include SAIFI, System Average Interruption Frequency Index; SAIDI, System Average Interruption Duration Index; and CAIDI, Customer Average Interruption Duration Index.

[117] Companies' Resp. to JI 1.19.a.

[118] Companies' Resp. to JI 1.19.

KU	LEXOC	LANSDOWNE SWITCHING	126
KU	LEXOC	VERSAILLES BYPASS	509
KU	LEXOC	LANSDOWNE SWITCHING	106
KU	LEXOC	LAKESHORE	135
KU	LEXOC	CLAYS MILL	145
KU	LEXOC	CLAYS MILL	147
KU	LEXOC	LANSDOWNE SWITCHING	24
KU	LEXOC	LEXINGTON WATER COMPANY 1	130
KU	LEXOC	PICADOME 12KV	112
KU	LEXOC	HALEY	45

Joint Intervenors appreciate the Companies' willingness to provide this data, and are encouraged to see that, on the particular reliability metric reported here—Customer Minutes Interrupted—some of the worst performing circuits will be receiving planned investments in this calendar year. Without additional data, however, it is not possible to draw robust conclusions

Going forward, Joint Intervenors recommend that the Companies provide further quantitative reporting of distribution planning metrics and discussion of concrete, planned distribution projects within the IRP itself. This may be data and planning that is already documented, or elsewhere reported to the Commission.[119] In any event, the next IRP could be improved with additional distribution system planning information, and the LBNL *Bridging the Gap on Data and Analysis for Distribution System Planning*

[119] In Section 8 of Volume I, the Companies note the development of "annual and long-term distribution system operations, maintenance, and investment plans designed to provide safe, reliable, resilient, secure and high-quality electric service to customers at a fair cost." IRP Vol. I at 8-9.

report, Attach. JI-8, provides actionable recommendations with respect to data used to identify worst performing circuits, and ten additional distribution planning topics.

6. Conclusion

Joint Intervenors thank the Commission for the opportunity to provide comments and recommendations related to LG&E/KU's 2024 IRP. As set out in these comments and supporting expert reports, the Companies have made important improvements in this IRP yet still do not adequately evaluate all potentially cost-effective resource options and fail to do not provide the level of comprehensive analysis needed to support an actionable plan for the next 15 years. Given the serious flaws identified in their analysis and the lack of support to substantiate exponential increases in future demand, Joint Intervenors respectfully caution against the reliance of the Company's findings in pending or future CPCN applications.

Respectfully submitted,

Byron L. Gary
Ashley Wilmes
Kentucky Resources Council
P.O. Box 1070
Frankfort, Kentucky 40602
(502) 875-2428
Byron@kyrc.org
Ashley@kyrc.org

Counsel for Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association

Cassandra McCrae
Gilbert Zelaya
Earthjustice
1617 JFK Blvd.
Ste. 2020
Philadelphia, PA 19103
(215) 671-6493
cmccrae@earthjustice.org
gzelaya@earthjustice.org

CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, this is to certify that the electronic filing was submitted to the Commission on March 07, 2025; that the documents in this electronic filing are a true representation of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

____
Byron L. Gary

PUBLIC

LG&E-KU's 2024 Integrated Resource Plan: An Assessment

March 2025 – White Paper

Applied Economics Clinic

Prepared for: the Mountain Association (MA), Kentuckians for the Commonwealth (KFTC), Kentucky Solar Energy Society (KYSES), and Metropolitan Housing Coalition (MHC)

Authors:

Joshua R. Castigliego

Elizabeth A. Stanton, PhD

www.aeclinic.org

March 7, 2025

[AEC-2025-03-WP-01]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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About the Applied Economics Clinic

Based in Massachusetts, the Applied Economics Clinic (AEC) is a mission-based non-profit consulting group that offers expert services in the areas of energy, environment, consumer protection, and equity from seasoned professionals while providing on-the-job training to the next generation of technical experts.

AEC's non-profit status allows us to provide lower-cost services than most consultancies and when we receive foundation grants, AEC also offers services on a pro bono basis. AEC's clients are primarily public interest organizations—non-profits, government agencies, and green business associations—who work on issues related to AEC's areas of expertise. Our work products include expert testimony, analysis, modeling, policy briefs, and reports, on topics including energy and emissions forecasting, economic assessment of proposed infrastructure plans, and research on cutting-edge, flexible energy system resources.

Founded by Clinic Director and Senior Economist Elizabeth A. Stanton, PhD in 2017, AEC's talented researchers and analysts provide a unique service-minded consulting experience. Dr. Stanton has over two decades of professional experience as a political and environmental economist leading numerous studies on environmental regulation, alternatives to fossil fuel infrastructure, and local and upstream emissions analysis. AEC Senior Researcher Joshua R. Castigliego has more than six years of professional experience, working extensively on energy topics that include critiquing electric utility integrated resource plans and performance incentive mechanisms. AEC professional staff includes experts in electric, multi-sector and economic systems modeling, climate and emissions analysis, green technologies, and translating technical information for a general audience. AEC's staff are committed to addressing climate change and environmental injustice in all its forms through diligent, transparent, and comprehensible research and analysis.

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Economic and Policy Analysis of Energy, Environment and Equity

I. Introduction

An integrated resource plan (IRP) is an electric utility's roadmap of potential plans to meet future electric demand through a selection of supply- and demand-side resources. In Kentucky, each electric utility must file an IRP with the Kentucky Public Service Commission (PSC or the Commission) every three years.[1] The goal of an IRP is to identify the supply-side resources, demand-side resources, and resource retirements that will best achieve the lowest cost electric service for ratepayers, given the requirements or constraints set by state and federal law.

This Applied Economics Clinic (AEC) white paper sets out best practices for IRP modeling and reporting, and then assesses the Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively, LG&E-KU or the Companies) 2024 IRP filed on October 18, 2024 in Case No. 2024-00326[2] based on those criteria. Best practices are organized into five categories:

A. **Demand-Side Analysis:** Projections of future customer demand (peak load and annual energy) considering both energy savings measures (e.g., energy efficiency, demand-side management, etc.) and additions to demand (e.g., electrification, large load customers, etc.).

B. **Supply-Side Analysis:** Assessment of new and existing supply-side resources and corresponding operational characteristics and costs used to formulate modeling inputs.

C. **Modeling Structure:** Least-cost, optimization modeling of multiple scenarios of the future that explore key uncertainties and risks.

D. **Selection of Recommended Plan:** Evaluation and selection of a recommended resource plan based on key metrics, such as the net present value of system costs, emissions, reliability, cost exposure, market exposure, and job impacts, among other factors.

E. **Stakeholder Input:** Facilitation of a start-to-finish stakeholder process that fosters transparency and collaboration, and is inclusive and receptive to stakeholder input.

AEC prepared this white paper on behalf of the Mountain Association (MA), Kentuckians for the Commonwealth (KFTC), Kentucky Solar Energy Society (KYSES), and Metropolitan Housing Coalition (MHC) (collectively, the "Joint Intervenors"). Through its best-practices assessment, AEC finds that LG&E-KU's 2024 IRP is missing critical components and includes errors in forecasting key assumptions, resulting in an overall flawed least cost resource plan selection. To achieve their goal of identifying a least-cost plan for ratepayers while complying with Kentucky and federal laws, the Companies must address the issues raised in this white paper in their next IRP filing to align with best practice by using a more thorough methodology and correcting key errors in assumption values. In addition, due to the flaws identified in our review, LG&E-KU's 2024 IRP should not be relied upon in near-term certificate of public convenience and necessity (CPCN) filings (like the one filed on February 28, 2025 in Case No. 2025-00045) until its critical flaws are corrected. Without substantial corrections, the modeling findings and resource plan recommendations presented in the Companies' 2024 IRP cannot be relied upon for resource planning decisions.

[1] 807 KAR 5:058. (2021). *Integrated resource planning by electric utilities*.

[2] Kentucky Public Service Commission (KY PSC) Case No. 2024-00326. *Elec. 2024 Joint Integrated Resource Plan of Louisville Gas and Elec. Co. and Ky.Util. Co.* ("2024 IRP").

LG&E-KU, both subsidiaries of PPL Corporation, are regulated utilities that provide electric service to roughly 1 million customers in Kentucky and parts of Virginia. The Companies' generation mix is currently comprised of coal-fired (84 percent), gas-fired (15 percent), and renewable energy (1 percent).[3] In their 2024 IRP, the Companies propose a Recommended Resource Plan that they claim accounts for the possibility of high economic load growth and carbon dioxide (CO_2) regulation but has "no regrets" should these not come to fruition.[4] Our review disagrees with this assessment, finding that LG&E-KU's flawed methods lead to unreliable results.

Section II provides an overview of best practices among five IRP categories and a discussion of Kentucky laws impacting electric utility planning. Next, in Section III, LG&E-KU's 2024 IRP assumptions and methods are assessed against 23 best practices divided into those five categories: (A) Demand-Side Analysis; (B) Supply-Side Analysis; (C) Modeling Structure; (D) Selection of Recommended Plan; and (E) Stakeholder Input. Section IV concludes the report with a summary of key takeaways and recommendations.

II. IRP Best Practices

To successfully identify least-cost resource plans for ratepayers, electric utilities align their IRP processes with a set of best practices, divided into the following categories and subcategories:

A. **Demand-Side Analysis:** (1) load forecasting; (2) demand-side resources; (3) behind-the-meter resources; (4) electrification loads; and (5) large load customers
B. **Supply-Side Analysis:** (1) all-resource RFP; (2) modeled resources; (3) regulatory costs; (4) fuel prices; and (5) technology costs
C. **Modeling Structure:** (1) future scenarios; (2) scenario assumptions; (3) base case; (4) resource portfolios; (5) retirement analysis; (6) optimization modeling; and (7) uncertainty analysis
D. **Selection of Recommended Plan:** (1) net present value comparison; (2) scorecard evaluation; (3) quantitative assessment; and (4) recommended plan
E. **Stakeholder Input:** (1) stakeholder input; and (2) transparency and accessibility

IRP processes use several modeling techniques to inform the utility planning decisions that ultimately affect ratepayer costs and reliable electric service. Resource decisions resulting from the IRP process have the potential to cause a significant impact on system costs and customer bills. An effective IRP process aims to minimize costs to ratepayers while building out a resource portfolio that balances affordability, sustainability, reliability, and resilience.

By following the best practices, electric utilities are able to comply with state and federal laws, assure reliable electric service, manage risks, and provide ratepayers with the lowest possible rates and bills.

When best practices are not followed in an IRP process, ratepayers bear the costs, and the Commission is exposed to potential reliability and cost crises. IRP best practices lead to the highest quality electric resource planning. Ignoring or omitting these steps can only lead to worse outcomes, greater risks, and higher costs.

[3] LG&E-KU, "We're creating a more sustainable energy future with the right mix – responsible, affordable and reliable," https://lge-ku.com/future.

[4] 2024 IRP, Executive Summary.

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Overview of best practices

When undertaking an IRP process, electric utilities must put their best foot forward and facilitate an assessment process that utilizes up-to-date information and data from well-verified sources to develop inputs and assumptions, strives to provide transparency and foster collaboration that is inclusive and receptive to stakeholder input, and leverages the best practices outlined in this report.

Based on AEC's extensive experience in electric utility resource planning, evaluation of IRPs around the country, and electric system modeling practices, Table 1 below provides a detailed list of IRP best practices, from building realistic demand and supply assumptions, to comprehensive modeling processes, to the selection of a preferred resource plan that is in ratepayers best interest, and the start-to-finish stakeholder review process that is so essential to a transparent IRP planning process.[5]

Table 1. Integrated resource planning best practices

A. Demand-Side Analysis
1. Load forecasting: Provide historical and forecasted annual demand and winter/summer peak broken down by customer class; forecasts should include number of customers, use per customer, and total usage.
2. Demand-side resources: Provide all existing and new planned demand-side resources included in annual and peak forecasts with clear evidence and justification.
3. Behind-the-meter resources: Provide all existing and expected customer behind-the-meter (BTM) resources included in annual and peak forecasts with clear evidence and justification.
4. Electrification loads: Provide projections of all new loads, such as those from electrification of transportation (i.e., electric vehicles) and buildings (i.e., electric heat pumps) sectors included in annual and peak forecasts with clear evidence and justification.
5. Large load customers: Provide assumptions regarding all new large load customers (e.g., data centers, cryptocurrency mining, etc.) included in annual and peak forecasts with clear evidence and justification.
B. Supply-Side Analysis
1. All-resource RFP: Conduct a competitive, all-resource request-for-proposals (RFP) for new resources based on real-world market availability and costs and provide bid results.
2. Modeled resources: Provide all supply- and demand-side resources available for model selection including operational characteristics and any limitations. Supply- and demand-side resources should be considered on a level playing field.
3. Regulatory costs: Provide all regulatory costs modeled for existing and proposed resources (e.g., required environmental compliance equipment or emissions fees).
4. Fuel prices: Provide all fuel price projections used in modeling. Fuel prices should be based on recent well-verified sources and easily compared to publicly available sources.
5. Technology costs: Provide all modeled costs for new and updated technology. Technology costs should be based on recent well-verified sources, easily comparable to publicly available sources, and inclusive of all available tax credits and/or other public incentives.

[5] While this best practice guidance was developed from AEC experts' own experience reviewing IRPs around the nation, other IRP best practice guides do exist providing similar criteria. For instance: Synapse and LBNL, Best Practices in Integrated Resource Planning (Nov. 2024), https://eta-publications.lbl.gov/sites/default/files/2024-12/irp_best_practices_2024_synapse_lbnl_24-061_0.pdf

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Table 1 (continued). Integrated resource planning best practices

C. Modeling Structure
1. Future scenarios: Select a range of reasonable scenarios of the future exploring key uncertainties and risks (e.g., fuel prices or emissions fees) based on recent well-verified sources, easily comparable to publicly available sources.
2. Scenario assumptions: Develop specific forecasted values to underly each of the designated future scenarios.
3. Base case: Identify one scenario as a base case or starting point to facilitate consistent comparisons across multiple future scenarios.
4. Resource portfolios: Model and provide multiple options of portfolios of resources, retirements and limitations.
5. Retirement analysis: Conduct and provide a retirement analysis to evaluate whether existing resources could retire earlier on an economic basis (rather than solely evaluating fixed retirement dates) that includes an assessment of avoidable, forward-looking costs.
6. Optimization modeling: Conduct and provide (at a minimum) input and output files of long-term, system-wide modeling optimizing for least-cost solutions (i.e., capacity expansion and production cost modeling). Allow model to optimize resource additions and retirements but limit the use of hardcoded constraints on the model.
7. Uncertainty analysis: Conduct and provide uncertainty analysis using stochastic modeling approaches (e.g., Monte Carlo) and using range of possible scenario assumption values considered.
D. Selection of Recommended Plan
1. NPV comparison: Include in recommended plan selection (at a minimum) consideration of the net present value (NPV) of system costs (or revenue requirements) of all modeling runs. Provide NPV system cost results for all portfolios modeled under all scenarios. Utilize optimization modeling to evaluate all portfolios against all scenarios with the goal of identifying a least-cost portfolio for ratepayers.
2. Scorecard evaluation: Include in recommended plan selection a scorecard comparing all modeling runs on factors that are important to the Commission's decision-making, including NPV of system costs, emissions, reliability, cost exposure, market exposure, and job impacts, among other factors. Provide quantitative values for scorecard metrics results for all portfolios modeled under all scenarios along with clear evidence and justification for each metric.
3. Quantitative assessment: Evaluate scorecard metrics for use in recommended plan selection based on quantitative and cardinal values, and not qualitative assessment or ordinal ranking.
4. Recommended plan: Select recommended plan from among the resource plans that were subject to modeling. In the event that an unmodeled resource plan is selected for recommendation, the company must run it through their modeling, evaluate it against the scorecard metrics (including the NPV of system costs) of the other resource plans, and provide that analysis.
E. Stakeholder Input
1. Stakeholder process: Facilitate a stakeholder process that seeks input early in the IRP process, starting with assumptions before moving onto modeling results. Be open to adding portfolios and scenarios based on stakeholder recommendations.
2. Transparency and accessibility: Provide necessary information and data (e.g., background materials on methods, data, and assumptions) together with the IRP report (and not later as a result of discovery requests) to allow the Commission, stakeholders, and technical experts to review and assess all aspects of the IRP process. Report modeling results in a way that is transparent and easy to understand.

Kentucky law governing electric utility planning

In Kentucky, each electric utility must file an IRP with the PSC every three years.[6] As part of their IRPs, each electric utility must provide a plan summary that discusses load growth projections, the resources planned to meet that growth, and any significant changes since the utility's last IRP filing.[7] Each electric utility must conduct load forecasting and develop a resource assessment and acquisition plan for a specified 15-year IRP modeling period.[8] In addition, each electric utility's IRP must provide financial information including: (1) present value of revenue requirements (PVRR) in dollar terms, (2) discount rate used in present value calculations, (3) annual revenue requirements provided in nominal and real terms, and (4) annual average system rates.[9]

In doing so, each utility must consider legislation that may impact resource decisions being made through its IRP process, including:

- *SB4: An Act Relating to the Retirement of Fossil Fuel-fired Electric Generating Units and Declaring an Emergency* (KRS 278.264)
- *SB349: An Act Relating to Energy Policy and Declaring an Emergency* (KRS 164.2807)

Senate Bill 4 (SB4), *An Act Relating to the Retirement of Fossil Fuel-fired Electric Generating Units and Declaring an Emergency,* was introduced to the Kentucky Senate on January 19, 2023,[10] and eventually passed to become law without the Governor's signature on March 29, 2023.[11] KRS 278.264 grants PSC the authority to approve or deny the retirement of utility-owned electric generators. Utilities must apply to PSC for an order approving the retirement of electric generating units.

KRS 278.264 also includes a "rebuttable presumption"[12] against fossil-fuel retirements whereby PSC will not approve the retirement of a fossil-fuel electric generating unit, or any decommissioning or other cost recovery requests, unless provided evidence that:

- The utility will replace the unit with new electric generating capacity that is dispatchable, maintains or improves the reliability and resilience of the grid, and maintains the minimum reserve capacity.
- The retirement will not increase net incremental ratepayer costs that would otherwise be avoided by continued operation.
- The retirement is not the result of financial incentives or benefits offered by any federal agency.[13]

Utilities are also required to provide PSC with evidence of direct and indirect costs of retiring the unit, including a demonstration that the retirement will result in cost savings for customers. Lastly, KRS 278.264 requires the PSC to submit an annual report to the Legislative Research Commission providing an overview of retirement

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[6] 807 KAR 5:058 (2021).

[7] *Id.*

[8] *Id.*

[9] *Id.*

[10] Ky. Gen. Assembly, Senate Bill (SB) 4, *An Act Relating to the Retirement of Fossil Fuel-fired Electric Generating Units and Declaring an Emergency* (2023), https://apps.legislature.ky.gov/record/23rs/sb4.html.

[11] 2024 KY Acts Chapter 118, SB 4.

[12] An assumption inferred from a given set of facts/evidence. *See* Legal Information Institute, Rebuttable Presumption, Cornell Law School, https://www.law.cornell.edu/wex/rebuttable_presumption.

[13] KRS 278.264 (2024).

requests, impact of approved retirements on fuel mix, required capacity reserve margins, need for capacity additions, expansions, or purchase power or capacity reserve arrangements, and stranded costs to be recovered through customer charges.[14]

On February 27, 2024, Senate Bill 349 (SB349), *An Act Relating to Energy Policy and Declaring an Emergency*,[15] was introduced to the Kentucky Senate and eventually passed to become law on April 12, 2024 over the veto of the governor.[16] KRS 164.2807 describes a set of "findings and declarations" regarding the importance of fossil-fuel electric generating facilities in Kentucky and establishes an Energy Planning and Inventory Commission (EPIC), requiring that body to submit its first annual report by December 1, 2024 that must include recommendations "for statutory changes or budgetary proposals, to the Legislative Research Commission, the Governor, and the Public Service Commission" pertaining to the adequacy of existing and future electric generation.[17] Under KRS 164.2807, fossil-fuel unit retirement applications submitted to the PSC pursuant to KRS 278.264 must be preceded by a notice to EPIC, and include a report from the executive committee. Furthermore:

> *Any order of the Public Service Commission in a proceeding under KRS 278.264 shall contain specific written findings of fact or conclusions of law addressing whether the executive committee's findings and recommendations were considered by the Public Service Commission.*[18]

The executive committee is also permitted to participate in proceedings before the PSC as an intervening party.[19] SB349 also added definitions of "dispatchable" and "intermittent" that effectively prohibits the replacement of fossil fuel-fired generation with any sort of non-thermal generation.

To abide by these state laws, LG&E-KU must carefully consider the lead time required to make certain resource decisions, especially those pertaining to the retirement of fossil-fuel electric generating facilities, given the need for advanced notice to EPIC, and opportunity for a report from the executive committee to be created and incorporated into the final application.

In the next section, LG&E-KU's 2024 IRP is evaluated against the IRP best practices introduced above to provide an assessment of the quality of their resource planning and effect of any failures in resource planning on ratepayers.

III. Assessment of LG&E-KU's 2024 Integrated Resource Plan

While LG&E-KU's 2024 IRP conforms with some best practices, it misses the mark on many others. AEC assessed the Companies IRP development and presentation based each of the 23 IRP best practices presented above. For each criterion we present a summary of LG&E-KU's practices pertaining to that specific best

[14] KRS 278.264 (2024).

[15] Ky. Gen. Assembly, SB349, *An Act Relating to Energy Policy and Declaring an Emergency* (2024), https://apps.legislature.ky.gov/record/24rs/sb349.html.

[16] 2025 KY Acts Chapter 172 (SB 349).

[17] KRS 164.2807.

[18] *Id.*

[19] *Id.*

practice, a review describing the Companies' successes and failures, and detailed recommendations to improve current practices.

A. Demand-Side Analysis

Thorough demand-side analysis is a necessary and foundational part of the integrated resource planning process. LG&E-KU's 2024 IRP includes several important components of demand-side resource potential, but misjudges and gives short shrift to others. Directionally, the result is an IRP that likely exaggerates the need for supply-side resource additions.

Our review of **Best Practice A.1. Load forecasting** found that the Companies have not made sufficient data available explaining their forecasted growth in the number of residential customers and expected increase in demand from large commercial customers—key bases on which LG&E-KU build their assumption of rapid load growth. With regards to **Best Practice A.2. Demand-side resources**, LG&E-KU has failed to provide options for expanding demand-side resources as load sensitivities or available for selection in their optimization modeling. An assessment of **Best Practice A.3. Behind-the-meter resources** revealed that the Companies have not considered more rapid solar adoption with increased rates and have failed to include forecasts of residential and commercial battery storage adoption in their load forecasting. To better align with **Best Practice A.4. Electrification loads**, LG&E-KU would need to provide a clear justification for its EV stock projections and a clear, data-based presentation of its heating electrification projections. Finally, the Companies' methods do not conform with **Best Practice A.5. Large load customers**. LG&E-KU should provide documentation and a clear rationale supporting its high expectations for data centers locating in the territory over the next five years. The Companies assume 4 to 9 percent of total U.S. data center load using studies that instead suggest much lower data center growth for Kentucky.

LG&E-KU's failure to examine their resource portfolios against a useful range of load forecasts raises questions regarding the reliability of 2024 IRP modeling for use in supporting near-term CPCN requests. Overall, the Companies' lack of transparency undermines their IRP modeling results and resource plan recommendations.

Best Practice A.1. Load forecasting: Provide historical and forecasted annual demand and winter/summer peak broken down by customer class; forecasts should include number of customers, use per customer, and total usage.

Overview: LG&E-KU's insufficient justification for their two largest drivers of growth in customer demand (new residential customers and new large commercial customers) undermines the reliability of their modeling results.

LG&E-KU practices

In the 2024 IRP, the Companies provide three load forecasts over a 15-year period, from 2024 to 2039: a mid (or base) load profile, a low load profile, and a high load profile (*see* Figure 1).[20] When annual average growth in customer demand is considered for the 2025 to 2032 period, the mid and high load compound annual growth rates (CAGRs) are double that of the modeling period as a whole: low load, -0.42 percent; mid load, 3.24 percent, and high load, 5.47 percent. While the Companies provide modeling for all three forecasts, they

[20] 2024 IRP, Volume I. p.5-15.

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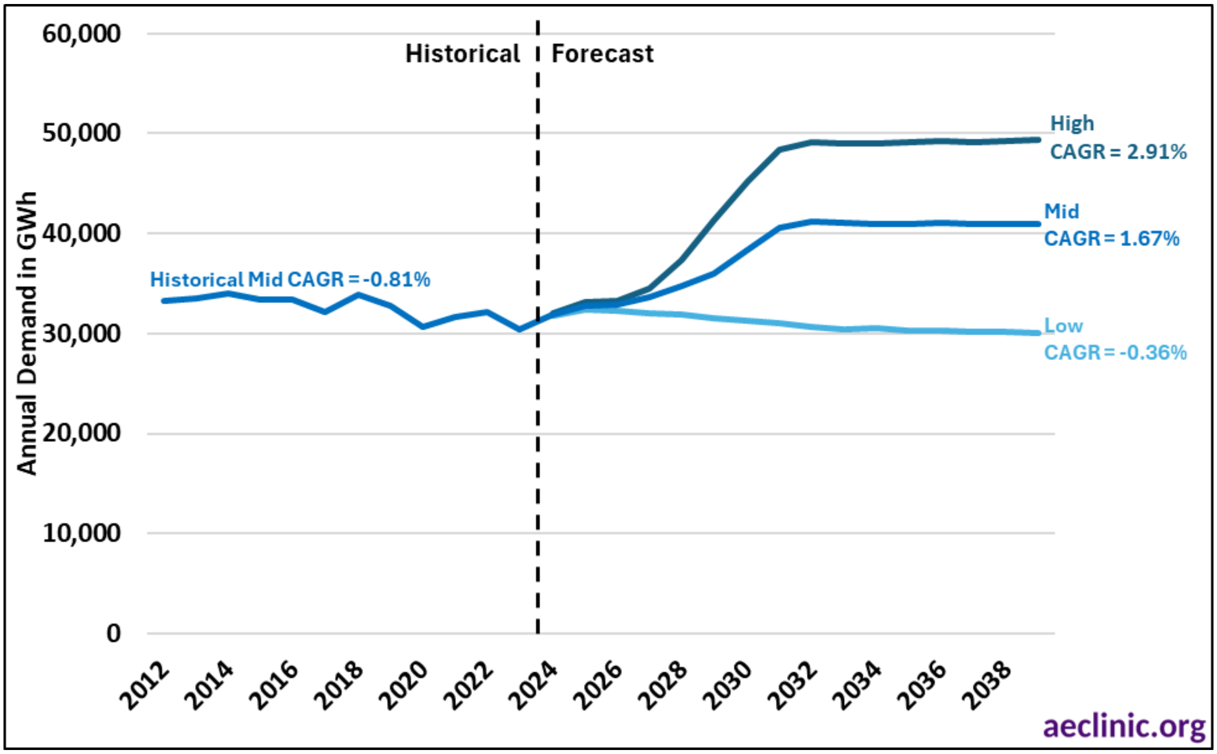
predict a low likelihood of the low load forecast profile occurring—due to current economic development and the growth of data centers—and focus primarily on the mid forecast in the IRP. [21] In all three forecasts, the Companies assume adoption of energy reducing measures per their 2024-2030 DSM-EE Program Plan (as well as new programs post-2030) and projected adoption of distributed generation resources.[22]

Figure 1. Historical and forecasted annual demand by scenario (GWh)



Data source: 2024 IRP Workpapers. Load Forecasting. "20240922_TotalEnergyRequirementsFigure.xlsx".

The 2024 IRP report presents several key forecast assumptions and uncertainties varied across the three load forecasts; weather, cost of service, and the number of commercial/industrial customers do not vary by load forecast.[23] LG&E-KU's key load forecasting variables are: economic development, efficiency, customer growth, distributed generation and battery storage, electric vehicles, and space heating electrification.[24]

The Companies assume that there will be "normal" or average weather in every year of the planning period.[25] Given this, weather is held constant across the three load scenarios and does not account for any differences between long-term energy requirement forecasts. The "normal" weather forecast is developed using historical data for the past 20 years and does not account for recent and expected climatic change.[26]

For the mid load forecast, the Companies use economic assumptions from the S&P Global Market U.S.

[21] *Id.* at p.5-15.

[22] *Id.* at p.5-16.

[23] *Id.* at p.5-16; Response to JI-1 Question No. 44.

[24] 2024 IRP, Volume I. pp.5-16 to 5-22.

[25] *Id.* at p.7-14.

[26] *Id.* at p.7-14.

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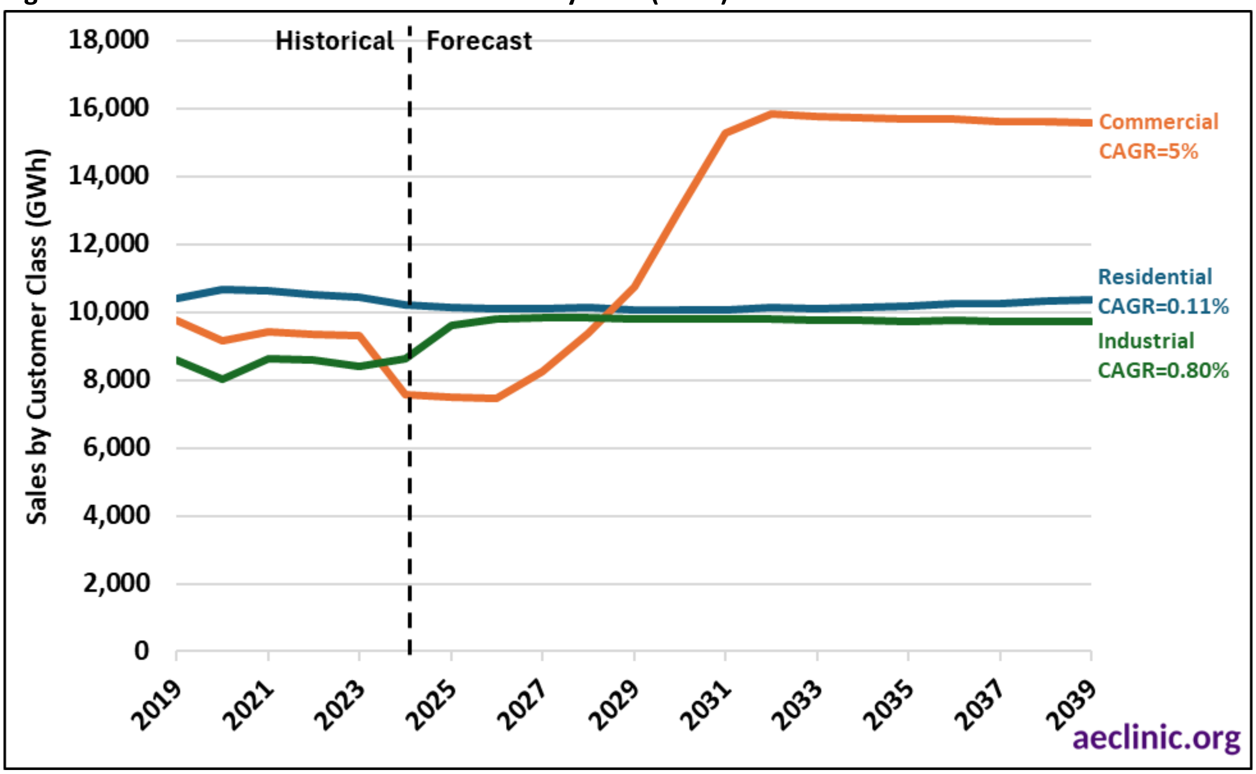
Economic Outlook.[27] The IRP states this Outlook projects real economic growth in Kentucky to be "2.3 percent during 2024," similar to the overall United States projections.[28] Between 2025 and 2029, Kentucky's average economic growth rate is projected to be 1.2 percent; over a longer term period, 2030 to 2039, the S&P Global projects an average growth rate of 1.5 percent.[29] Detailed economic assumptions for the high and low load profiles were not provided.

LG&E-KU's energy demand growth is driven almost entirely by commercial customers (*see* Figure 2), as discussed in more detail in Best Practice A.5. After taking into account expected demand-side measure (DSM) energy savings (*see* Best Practice A.2), residential demand is forecasted to remain at or near 2024 levels. Industrial demand is forecast to rise in 2025 and 2026, and then remain steady through the remainder of the modeling period.

Figure 2. LG&E-KU annual customer demand by class (GWh)



Data source: (1) 2024 IRP, Volume I. Tables 7-19 and 7-20; (2) 2024 IRP, Volume I. Tables 7-3 and 7-4; (3) 2024 IRP Workpapers. Load Forecasting. "RS_Comm_UPC_Calc_20240912.xlsx".

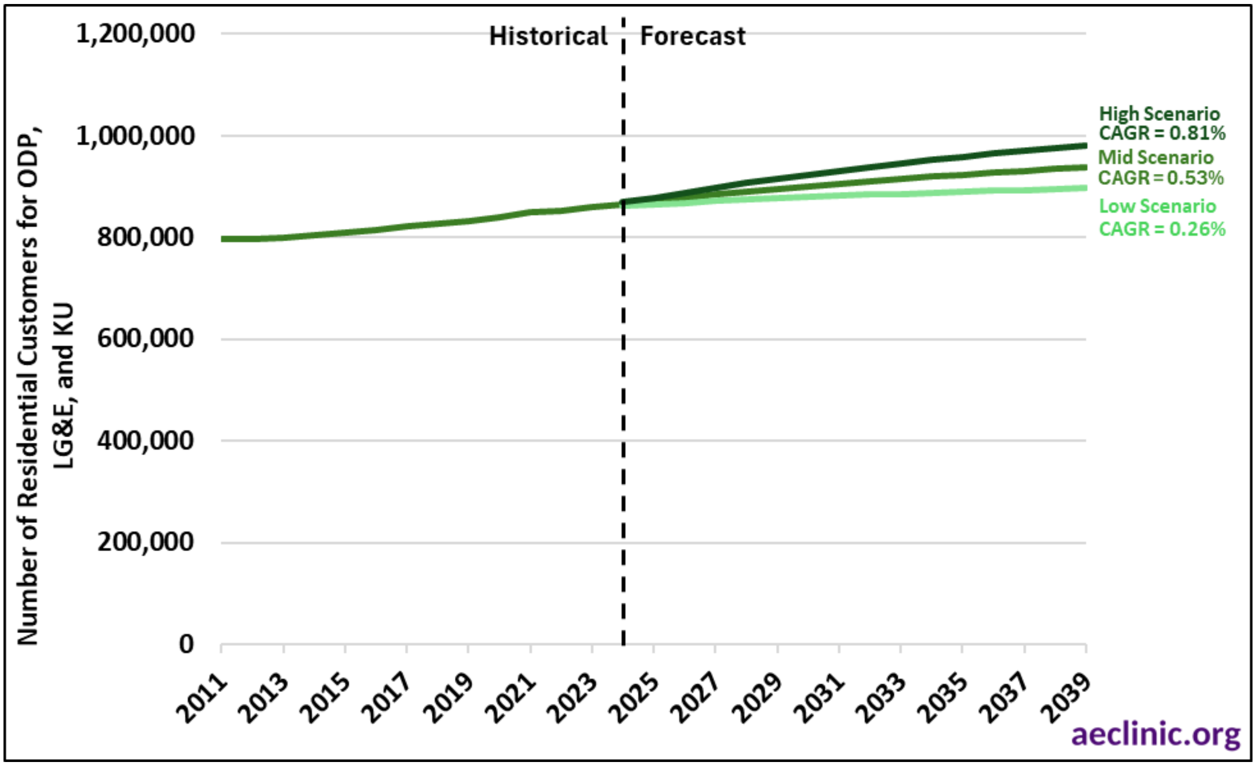
The Companies project the number of residential customers to grow at a CAGR of 0.53 percent from 2025 to 2039 in their mid load forecast (2024-2039) (*see* Figure 3 below). In the high and low load forecasts, the Companies project the number of residential customers will have CAGRs of 0.81 percent and 0.26 percent, respectively.

[27] *Id.* at p.7-14.

[28] *Id.* at p.7-15.

[29] *Id.*

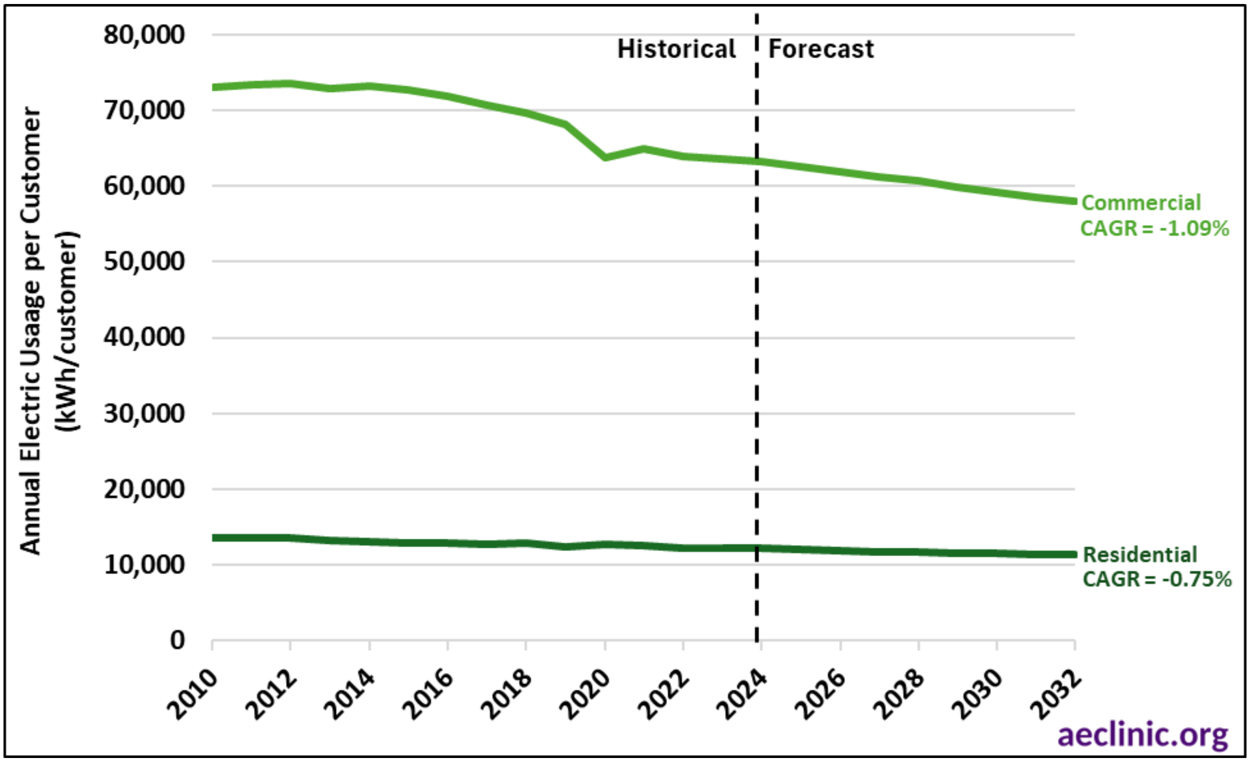
Figure 3. LG&E-KU's historical and forecasted residential customer count



Data source: 2024 IRP Workpapers. Load Forecasting. "RS_Cust_Growth_CAGR.xlsx".

LG&E-KU's annual electric usage overall, as well as electric usage per customer has fallen over time. Their projected average usage per residential customer and per commercial customer continue to fall throughout the modeling period (*see* Figure 4 below).

Figure 4. LG&E-KU's historical and forecasted annual electric usage per residential and commercial customer



Note: LG&E-KU's use per customer data are only provided through 2032 rather than extending out to the end of the modeling period (i.e., 2039). Data source: 2024 IRP Workpapers. Load Forecasting. "RS_Comm_UPC_Calc_20240912.xlsx".

Review

The Companies' projection of flat growth in residential demand relies on their assumption of high growth in the number of residential customers: 0.53 percent per year, compared to the State of Kentucky's population growth forecast of 0.23 percent over the same period.[30] LG&E-KU points to growing housing starts to explain their forecast of rapid residential customer growth, but these data were not made available for review: "S&P Global is forecasting total housing starts in Kentucky to be the eighteenth highest in the United States during 2024. Further, the forecasted 2024-2039 growth rate averages tenth in the US as compared to the average rate over the previous ten years."[31] Assumed customer growth is an important driver of energy requirements and, therefore, recommendations for resource additions.

In 2031, the economic development increase to peak load (from 2024) is 97 percent of the total increase to peak load in the mid load profile and 91 percent in the high load profile. This large, forecasted increase in commercial demand is largely unsubstantiated in the 2024 IRP (*see* Best Practice A.5 for a discussion of expected data center and other large customer growth in demand).

Recommendations

The Companies should make additional data available explaining their forecasted growth in the number of

[30] Ky. State Data Ctr. – Univ. of Louisville, Population and Household Projections Kentucky, Kentucky Counties, and Area Development Districts 2020-2050, (2022), https://louisville.app.box.com/s/ndp7uvqbi6xtsv1sd2ylntvaer02kklq.

[31] 2024 IRP, Volume I. p.7-18

residential customers and expected increase in demand from large commercial customers (*see* Best Practice A.5 below, for more on Large Load Customers). These two projections are key bases on which LG&E-KU build their assumption of rapid load growth, but the limited information provided regarding their development is not sufficient for review by the Commission, stakeholders, and their third-party experts. Adequate documentation and explanation of load forecasts are essential to every utility's IRP. This lack of transparency undermines the Companies' IRP modeling results and resource plan recommendations and calls into question the appropriateness of their use in near-term CPCN approval cases.

Best Practice A.2. Demand-side resources: Provide all existing and new planned demand-side resources included in annual and peak forecasts with clear evidence and justification.

Overview: LG&E-KU appear to accurately represent their existing and planned demand-side measures in load forecasting, but fail to incorporate potential benefits of increased levels of demand-side resources in modeling.

LG&E-KU practices

The Companies mid load forecast includes nearly 1,500 GWh cumulative reduction in annual demand by 2032 from energy efficiency improvements through their Income-Qualified Solutions, Business Solutions, and Connected Solutions programs.[32] When forecasting energy efficient improvements, the Companies account for the Inflation Reduction Act (IRA), which is expected to incentivize the adoption of energy efficient technologies and electrification.[33] The mid load forecast assumes energy efficiency implementation that the Companies describe as consistent with the expectation of IRA funding: LG&E-KU's 2024 IRP reports that 2039 energy efficiency improvements in the mid forecast lower residential and commercial sales by a cumulative 7.5 percent (*see* Figure 5 below).[34]

[32] 2024 IRP, Volume I. p.7-15.

[33] *Id.*

[34] *Id.*

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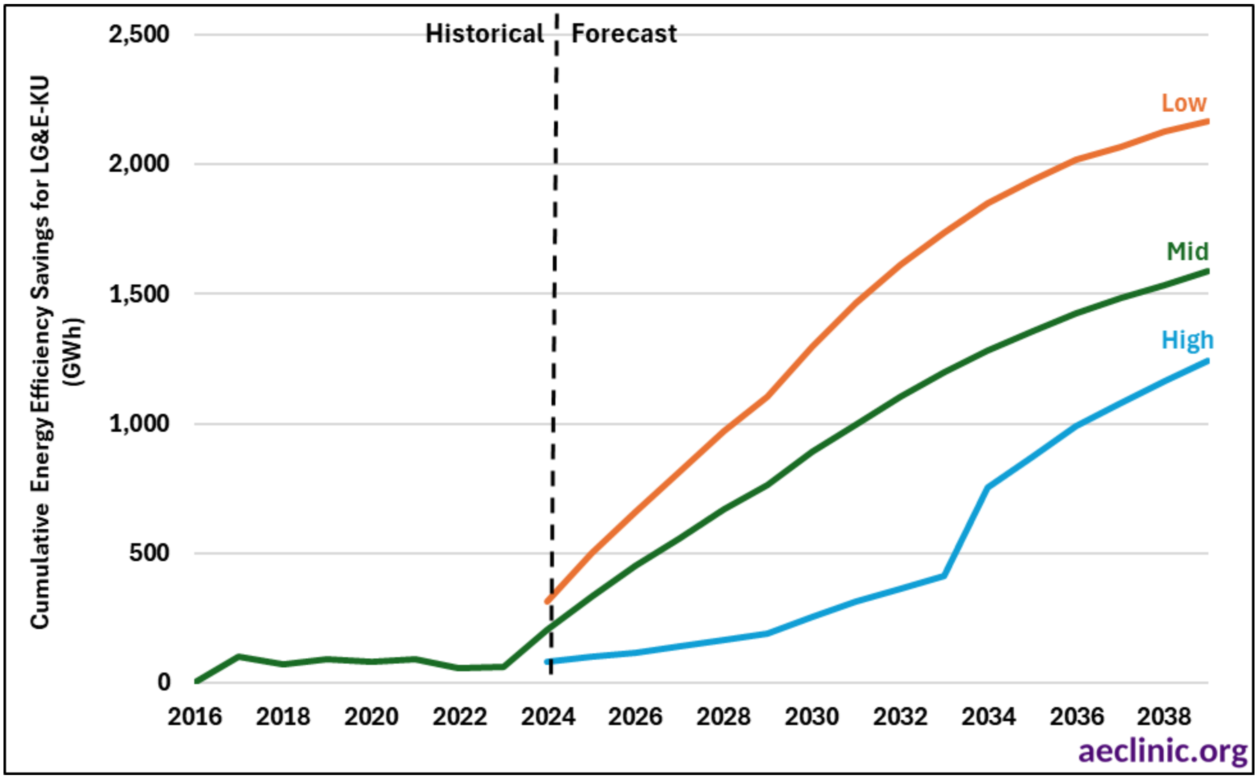
Figure 5. LG&E-KU cumulative demand-side savings (GWh)



Data source: (1) 2024 IRP Workpapers. Load Forecasting. "Section7_Charts_AWJ_20240903.xlsx"; (2) 2024 IRP Volume I. Figure 7-2. p.7-17

The Companies present plans to introduce four additional programs in 2025 and 2026: Peak Time Rebates, and Residential Online Audit and Rebates in 2025; and Appliance Recycling and Business Midstream Lighting in 2026.[35] In addition, the Companies list four demand response programs as part of their 2024-2030 DSM-EE plans: BYOD Smart Water Heaters; BYOD Smart Thermostats – Cooling Season; BYOD Smart Thermostats – Heating Season; and BYOD – Smart Wall HVAC Units. Four additional programs are listed in the 2024 IRP but are not part of the 2024-2030 DSM-EE plans: BYOD Energy Storage; BYOD Whole Home Generators; and two Business Demand Response programs (one for >200 kW Base Demand and another for 50-200 kW Base Demand).[36] In addition, LG&E-KU included demand response programs for model selection—dispatchable DSM program measures, and an expansion of the Companies' Curtailable Service Rider (CSR) program (*see* Best Practice B.2).

Review

LG&E-KU's anticipated energy savings in residential and commercial sales are more than 1,500 GWh in 2039 in its mid load profile (or 99 GWh average annual incremental growth)—a substantial increase from recorded annual incremental energy savings of 59 GWh in 2023 but a decrease in savings as a share of total demand in every scenario (*see* Figure 6 below).[37]

[35] 2024 IRP, Volume I. p.5-3.

[36] *Id.* at p.8-26, Tbl. 8-16.

[37] 2024 IRP Workpapers. Load Forecasting. "Section7_Charts_AWJ_20240903.xlsx"; 2024 IRP, Volume I. Figure 7-2., p.7-17.

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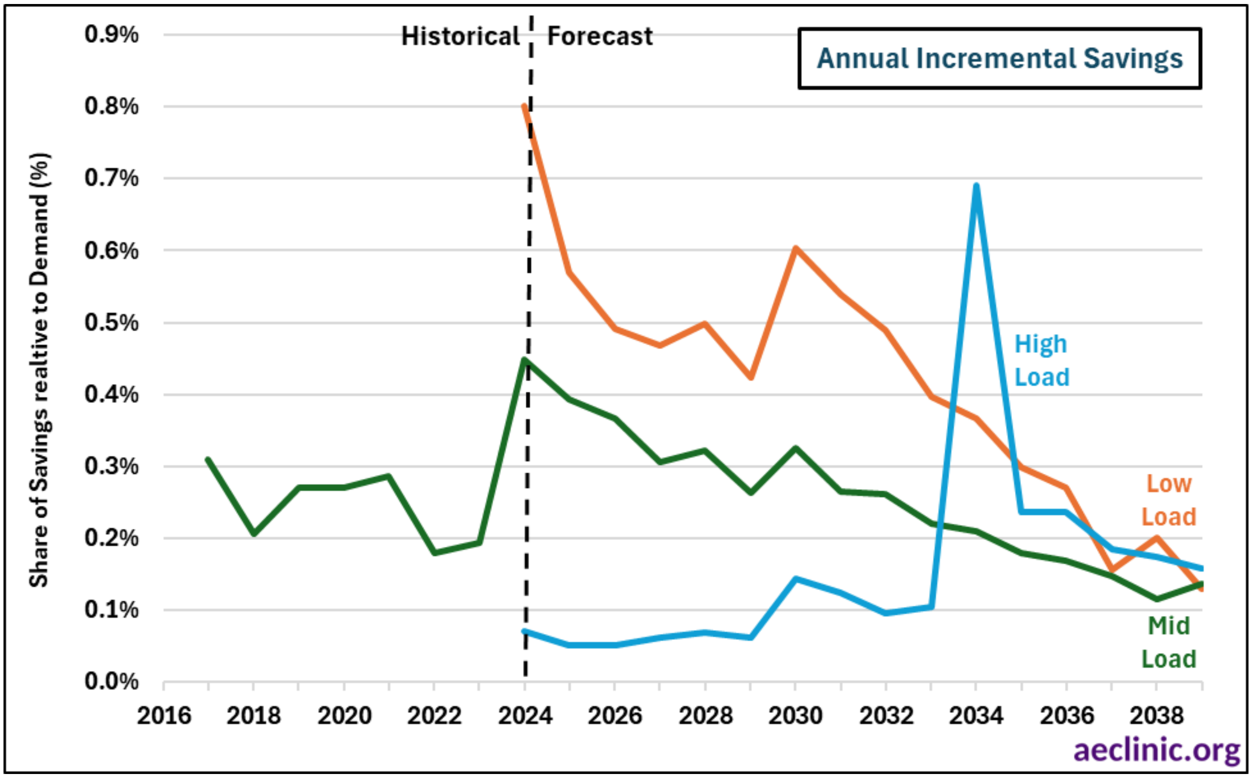
Figure 6. Annual incremental energy savings as share of customer demand



Data source: (1) 2024 IRP Workpapers. Load Forecasting. "Section7_Charts_AWJ_20240903.xlsx"; (2) 2024 IRP Volume I. Figure 7-2. p.7-17

For perspective, in 2021 Kentucky's annual incremental efficiency savings was 0.12 percent of total electric sales while LG&E-KU reported roughly 0.3 percent of annual incremental energy savings in the same year. Over time, the Companies have experienced a gradual decrease in annual incremental energy savings as a share of sales until 2023. The Companies' mid load profile projects at least 0.3 percent of savings each year from 2025 through 2032, but this share falls rapidly after measures approved in Case 2022-00402 cease. After 2030 annual incremental savings gradually drop to just 0.1 percent of sales by 2039.

In 2021, thirty-nine states had higher annual incremental savings than Kentucky, with savings shares ranging from 2.22 percent of sales in California to 0.12 percent of sales in Virginia. Only eleven states had lower savings: Mississippi, Louisiana, Nebraska, Florida, Ohio, Tennessee, Alabama, West Virginia, Kansas, North Dakota, and Alaska. While several of Kentucky's neighbors are performing worse in terms of annual incremental efficiency savings, Illinois is ranked in the top ten in ACEEE's 2022 State Energy Efficiency Scorecard with 1.69 percent annual incremental savings.[38] LG&E-KU's projected energy savings are small in comparison to many other states and shrinking in comparison to their own historical savings. Greater investment in energy efficiency and demand response measures has the potential to lower customer rates and bills.

Staff's Report on the 2021 IRP[39] encouraged LG&E-KU to "continue to monitor and incorporate anticipated

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[38] Sagarika Subramanian et al., 2022 State Energy Efficiency Scorecard, ACEEE (Dec. 2022), https://www.aceee.org/sites/default/files/pdfs/u2206.pdf.

[39] Case No. 2021-00393, Order, Appendix *Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Elec. Company and Ky. Util. Co.*, at p.67 (Sept. 16, 2022) ("Staff's Report on 2021 IRP").

changes in EE impacts in forecasts and sensitivity analyses.[40] Staff's Report further recommended that "LG&E/KU should identify and assess all potentially cost-effective demand-side resource options,"[41] and encouraged a particular focus on "continu[ing] to identify energy efficiency opportunities for large customers."[42] But LG&E-KU's inclusion of additional cost-effective efficiency potential beyond the already-approved programs is minimal and declining.

LG&E-KU also did not evaluate as part of the 2024 IRP "more aggressive options to increase use of the curtailable service rider and demand conservation program"[43] despite the 2021 IRP Staff Report recommendation along those lines. Instead, LG&E-KU appear to rely on plan levels as approved in Case No. 2022-00402 for measures through 2030. It is unclear why approval of existing programs and budgets should obviate the need to evaluate additional efforts to pursue cost-effective demand-side management potential in the context of long-range resource planning, particularly when required by regulation.[44]

Recommendations

While LG&E-KU appears to accurately represent their existing and planned DSM resources in load forecasting, they have failed to reexamine and expand the DSM resources available as modeling sensitivities or for selection in their optimization modeling (*see* discussion in Best Practices B.2 and C.6). Staff's Report on the 2021 IRP called on the Companies to "not assume that current DSM-EE programs will not be renewed. Further, in the context of a long-range planning study, it would be reasonable for the Companies to model increased participation in current programs up to their current limits."[45] Instead, the Companies' energy savings drop rapidly after 2030. The result is a failure to explore the sensitivity of the Recommended Resource Plan to lower potential loads and, therefore, a tendency towards assuming a greater need for supply resources. In line with Staff's prior recommendations and 807 KAR 5:058, the Companies should evaluate more aggressive options to increase the use of CSR and DSM-EE programs to reduce ratepayer costs.

Best Practice A.3. Behind-the-meter resources: Provide all existing and expected customer behind-the-meter (BTM) resources included in annual and peak forecasts with clear evidence and justification.

Overview: LG&E-KU's load forecasts may underestimate the potential for growth in behind-the-meter solar growth and omit any increase in behind-the-meter battery storage or its effects on forecasted load.

[40] Staff's Report on 2021 IRP, p.67.

[41] *Id.*

[42] *Id.* at p.68.

[43] *Id.*

[44] 807 KAR 5:058 Sec. 8(2)(b) ("The utility shall describe and discuss all options considered for inclusion in the plan including: . . . (b) Conservation and load management or other demand-side programs not already in place . . . .").

[45] Staff's Report on 2021 IRP, p.67.

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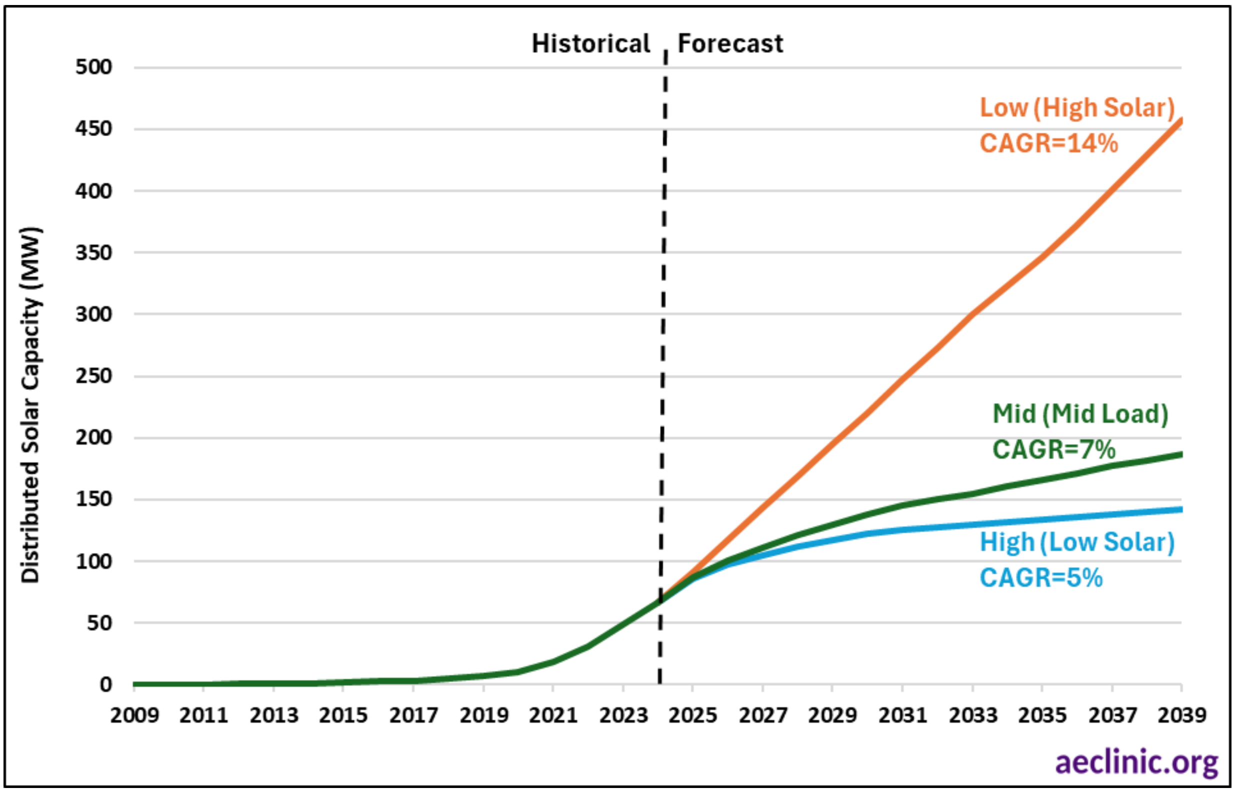
LG&E-KU practices

The Companies project that customers' distributed solar generation capacity will increase slowly in the mid and high load profile forecasts, and will experience a sharper increase over time in the low load profile (*see* Figure 7). By 2039 in the mid load profile, behind-the-meter solar amounts to 2 percent of the Companies' total capacity resources but does not adequately account for the potential for increased customer adoption if net metering rates were continued to be offered after the 1 percent of peak load threshold set in KRS 278.466(1). That increased adoption is captured in the low load profile.[46]

Figure 7. Historical and forecasted distributed solar generation (MW)



Data source: 2024 IRP Workpapers. Load Forecasting. "PV_EV_highLowBase_capacity2024.xlsx"

The Companies assume that non-solar distributed resources (including behind-the-meter battery storage) will not significantly affect load during the modeling period. The Companies cite "low rates of energy storage adoption, uncertainty around charging and discharging patterns, and unknown adoption numbers of battery storage for non-net metering customers" to explain why distributed battery resources are not explicitly forecasted.[47] At the end of 2023, the Companies had roughly 1.8 MW of behind-the-meter battery capacity, spread across 286 units. Additional adoption of distributed battery resources is not forecasted by the Companies.[48]

[46] 2024 IRP Workpapers. Load Forecasting. "PV_EV_highLowBase_capacity2024.xlsx"; 2024 IRP, Volume I. p. 5-20; 8-29.

[47] 2024 IRP, Volume I. p.5-21.

[48] *Id.* at pp.7-19 and 7-20.

Review

The Companies' behind-the-meter solar resources rose from 0.1 MW in 2009 up to 48.8 MW in 2023.[49] LG&E-KU's mid load forecasted CAGRs for distributed solar growth correspond reasonably well to EIA forecast of 6.8 percent annual growth at the national level from 2024 to 2039.[50] However, this growth rate assumes that above the 1 percent of peak threshold customers will be less likely to adopt behind-the-meter solar and ignores the potential for increased adoption rates if higher compensation levels were offered. The Companies' also provide little justification for their assumed growth rates in any scenario, which do not seem to be in line with previous growth on the Companies' systems and fails to address how Companies' decision-making can influence the rate of adoption or the cost-effectiveness of decisions such as imposing a cap on new net metering after 1 percent of peak load.[51]

With investment in behind-the-meter battery storage growing every year[52], the Companies' use of past adoption rates and excuses regarding limitations in past data collection are not adequate rationales for a continued practice of omitting behind-the-meter batteries from load forecasting. LG&E-KU also fails to implement one of Staff's load forecasting recommendations following the 2021 IRP: "LG&E/KU should expand its discussion of DERs to identify resources other than distributed solar that could potentially be adopted by customers and explain how and why those resources are expected to affect load, if at all."[53] Kentucky IRP regulatory requirements specify that "existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan" must be included in IRP modeling.[54]

Recommendations

Staff's Report on the 2021 IRP specifically called on the Companies to "analyze and discuss whether and the extent to which customers that would have taken service under Net Metering Service-2 tariff would continue to interconnect DERs even if they received no credit for energy sent back into the system because the one percent cap had been reached when they sought to connect."[55] LG&E-KU should consider additional scenarios with the potential for higher solar growth aside from in their low load scenario.

LG&E-KU should follow Staff's recommendation to include forecasts of residential and commercial battery storage adoption in their load forecasting. These resources have the potential to reduce peak load and the need for new capacity resources, a key component of planned customer costs. Excluding potential resources from analysis is a serious obstacle to the development of any least-cost plan. LG&E-KU's exclusion of non-solar behind-the-meter resources calls into question the reliability of IRP recommendations in guiding near-term CPCN approvals.

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[49] 2024 IRP Workpapers. Load Forecasting. "Net_Metering_History.xlsx".

[50] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2023 Table 21. Residential Sector Equipment Stock and Efficiency, and Distributed Generation [Workbook] (Mar. 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=30-AEO2023&cases=ref2023&sourcekey=0.

[51] Response to JI-1 Question No. 76.

[52] EIA, Battery Storage in the United States: An Update on Market Trends (July 24, 2023), https://www.eia.gov/analysis/studies/electricity/batterystorage/.

[53] Staff's Report on 2021 IRP, p.67.

[54] 807 KAR 5:058 Section 8(3)(d).

[55] Staff's Report on 2021 IRP, p.67.

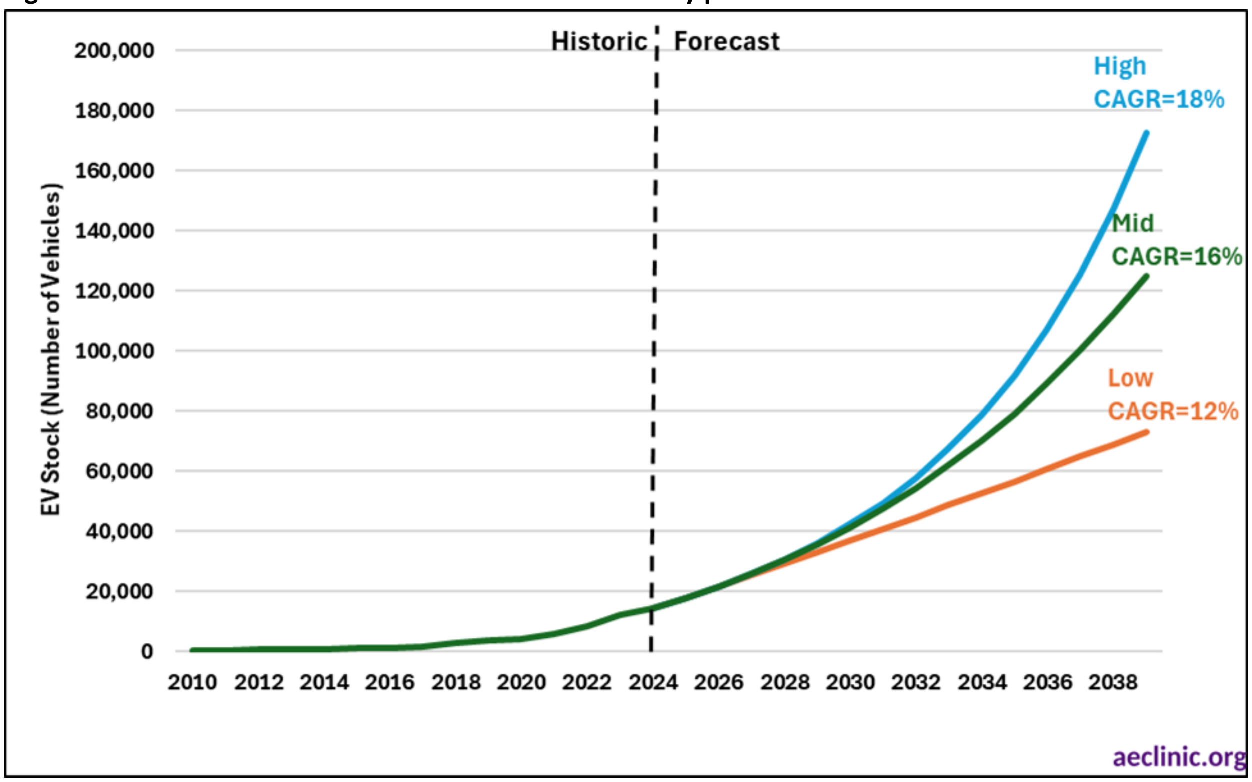
Best Practice A.4. Electrification loads: Provide projections of all new loads, such as those from electrification of transportation (i.e., electric vehicles) and buildings (i.e., electric heat pumps) sectors included in annual and peak forecasts with clear evidence and justification.

Overview: LG&E-KU use electric vehicle growth assumptions that underestimate the potential for future electrification load growth. Similarly, the Companies fail to consider added load from both heating electrification and climate-driven increases to heating and cooling load.

LG&E-KU practices

Electric vehicle (EV) stock in the Companies' service territory grew from 365 vehicles in 2010 to 12,169 vehicles in 2023 (*see* Figure 8). The Companies' projected annual growth in EVs in the modeling period is 12 percent, 16 percent, and 18 percent at low, mid, and high growth profiles, respectively.

Figure 8. LG&E-KU's historical and forecasted EV stock by profile



Data sources: 2024 IRP Workpapers. Load Forecasting. "EV_IRP_forecast.xlsx" and "PV_EV_highLowBase_capacity2024.xlsx".

The Companies' consideration of space heating electrification impacts on their load forecasts for residential customers is primarily driven by the uptake (or saturation) of electric heating technologies, such as electric furnaces, air-source heat pumps, and ground-source heat pumps.[56] LG&E-KU explain their assumption that higher space heating electrification rates do not necessarily coincide with more electric consumption:

> *All other things equal, cohorts with a higher electric heating penetration would be expected to consume more electricity annually on average, but this has not been the case for those added*

[56] Ky. Pub. Serv. Comm'n (KY PSC), Case No. 2024-00326. Response to JI-1 Question No. 48.

> *in recent years. For example, as seen in the tables above, despite a higher electric heating penetration, the average consumption in 2023 for premises added in 2022 (11,439 kWh for KU and 9,665 kWh for LG&E) is lower than that for premises added through 2010. This result reflects the previously mentioned gains in lighting and cooling end-use efficiencies as well as the fact that recent customer growth has been concentrated in urban areas where homes are smaller on average than in rural areas, in part due to the higher incidence of multifamily units in urban areas.*[57]

In addition, the Companies do not appear to have explicitly accounted for changes to cooling load over time and rely on a static forecast based on past weather patterns, without any consideration on the impacts of changing climate on heating and cooling demand: "The normal weather forecast is based on the most recent 20-year historical period."[58]

Review

Even the Companies' high EV profile CAGR (18 percent) is lower than historical EV growth in LG&E-KU's territory (33 percent)[59] and lower than the Edison Electric Institute's EV stock growth of 27 percent each year nationwide.[60] This comparison suggests that higher ranges of potential EV adoptions should have been explored in LG&E-KU's load profiles.

In explaining their decision to exclude additional load from heating electrification in their load forecasts, the Companies' assumptions regarding the impacts of demand-side measures and a change in use per customer over time seem misplaced. Changing expectations regarding energy savings and average use per customer should be represented transparently. Showing those changes netted against heating electrification for an assumed zero load growth is a faulty technique that obscures the mechanisms driving customer load.

Recommendations

LG&E-KU should provide a clear justification for its EV stock projections and a clear, data-based presentation of its heating electrification projections. These new electrification loads have the potential to be an important driving force in predicting the Companies' future annual and peak demand.

Best Practice A.5. Large load customers: Provide assumptions regarding all new large load customers (e.g., data centers, cryptocurrency mining, etc.) included in annual and peak forecasts with clear evidence and justification.

Overview: An increase in large load customers is a key driver of LG&E-KU's load forecast for which no accurate evidence is provided.

57 KY PSC, Case No. 2024-00326. LG&E-KU 2024 IRP, Volume I. p.7-32.

58 LG&E-KU IRP Volume II, p.7

59 KY PSC, Case No. 2024-00326. LG&E-KU 2024 IRP Workpapers. Load Forecasting. "EV_IRP_forecast.xlsx" and "PV_EV_highLowBase_capacity2024.xlsx".

60 Charles Satterfield et al*., Electric Vehicle Sales and the Charging Infrastructure Required Through 2035*, Edison Elec. Inst. (Oct. 2, 2024), https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Electric-Transportation/EV-Forecast-Infrastructure-Report.pdf?la=en&hash=FF7F1A5913E3B48E8F92FA26E2AFB79FDBE0E89C.

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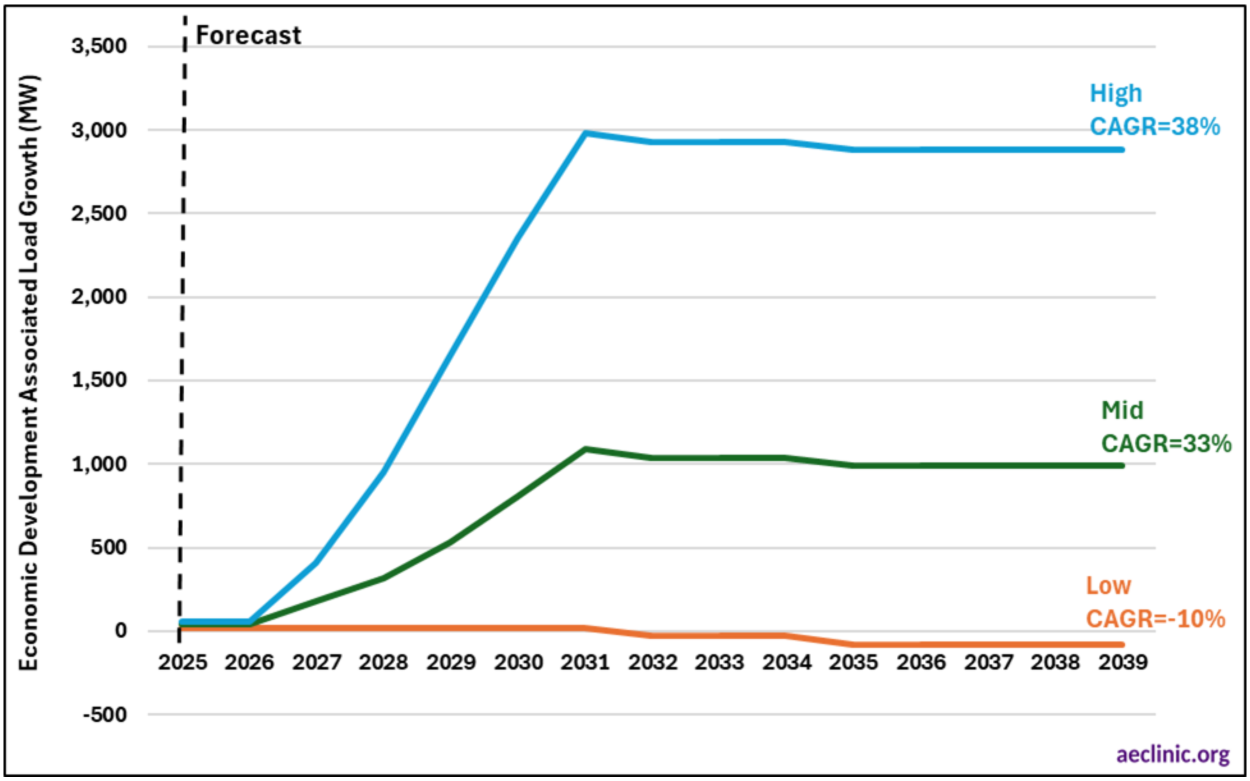
LG&E-KU practices

The Companies considered two main sources of the effects of economic development on load: data centers and new industrial projects like the Blue Oval SK electric vehicle battery production facility (BOSK).[61] The Companies point to Kentucky's economic growth in recent years, and expect the growth to continue, with a particular focus on new data centers. The Companies consider data centers as "a key load forecast driver in this IRP."[62] Three economic development load growth profiles were modeled to address uncertainty regarding future economic development: The mid load profile assumes that by 2032, an additional 1,050 megawatts (MW) of load will come from new data centers together with a single unidentified small economic development project (*see* Figure 9).[63]

Figure 9. LG&E-KU forecasted economic development load growth (MW)



Data source: 2024 IRP Workpapers. Load Forecasting. "Data_Center_Growth_Projections_20241008.xlsx".

The 2024 IRP asserts that this mid economic growth profile represents 4.2 percent of the total data center load growth predicted for the entirety of the United States in 2030, based on a 2023 study conducted by Newmark, and 9.4 percent of the national moderate growth projections shown in a 2024 study conducted by the Electric Power Research Institute.[64] Under the high economic growth profile, the Companies forecast an additional 1,750 MW of load (on top of the mid growth profiles assumptions) will be needed due to new data centers, the

[61] 2024 IRP, Volume I. pp.5-16; 7-12.

[62] *Id.* at p.5-13.

[63] *Id.* at pp.5-16; 7-13.

[64] *Id.* at p.7-14.

small project, and the second phase of the BOSK project. [65] Under the low load profile, the Companies assume no new data centers will enter the market and that several large customers will leave the service territory in the later half of the 2030s.[66] These "economic development" additions to load account for almost all of the change in commercial energy demand shown in Best Practice A.1.

Review

The Companies' project that their growth in customer load from (primarily) data centers will amount to 4 to 9 percent of total U.S. data center load without providing any rationale for this assumption. LG&E-KU's data center growth in the mid load forecast is 4.2 percent of the 18 gigawatts (GW) projected by Newmark Consulting nation-wide by 2030; the Companies' 2031 mid forecast is 6.1 percent of the U.S. total. While Newmark's estimates for particular jurisdictions are for growth to 2027 and total market size, LG&E-KU's assumptions most closely resemble that of the Dallas/Fort Worth area and are surpassed only by Northern Virginia. The other four "Key U.S. Data Center Markets" flagged by Newmark (Phoenix, Bay Area/Silicon Valley, Chicago, and Columbus, Ohio) are all forecasted to have lower data center growth than that adopted by the Companies for their territory.[67]

EPRI projects 44 to 252 terawatt-hours (TWh) of data center growth from 2023 to 2030 nation-wide. LG&E-KU's forecast for 2030 is 9.4 percent in the mid load profile and 7.5 percent under high load. By 2031, LG&E-KU's forecast reaches 13.2 percent of EPRI's 2030 U.S. total. Kentucky is not included among EPRI's top 15 states for projected data center growth and is assigned to the lowest grouping for expected data center electric consumption as a share of total state demand. EPRI's moderate growth scenario projects 0.7 additional TWh in Kentucky, or 1.1 percent of the U.S. total.[68]

LG&E-KU's 1 million customers make up just 0.6 percent of total U.S. electric customers.[69] The Companies' unsubstantiated 11 to 20 percent forecasted increase in LG&E-KU's total 2030 customer load is driving the Companies recommendation of new capacity investments that represent significant costs to customers. In contrast, under the low load profile, the Companies assume no new data centers will enter the market and that several large customers will leave the service territory in the later half of the 2030s—and then proceed to discard their own low load forecast as implausible. Use of a reasonable range of assumptions—both high and low—in load forecasts is an essential component of every IRP. Key assumptions driving load forecasts must be adequately documented and substantiated; the Companies' comparisons to Newmark and EPRI forecasts were flawed and were offered without necessary context.

Recommendations

LG&E-KU should provide documentation and a clear rationale supporting its high expectations for data centers locating in the territory over the next five years. The Companies use of a 4 to 9 percent of total U.S. data center

[65] *Id.* at p.7-13.

[66] *Id.* at p.7-14.

[67] 2023 U.S. Data Center Market Overview & Market Clusters (Jan. 2024), https://www.nmrk.com/storage-nmrk/uploads/documents/2023-U.S.-Data-Center-Markets.pdf.

[68] Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption (May 2024), https://www.epri.com/research/products/000000003002028905.

[69] Statista Rsch. Dep't, Number of ultimate customers served by the electric industry in the United States between 1998 and 2023 (Jan. 2025), https://www.statista.com/statistics/195751/number-of-ultimate-customers-of-the-us-electric-industry-since-1998/.

load is not consistent with the context given in reports to which they attribute those values: Those studies instead suggest much lower data center growth for Kentucky. LG&E-KU's failure to examine their resource portfolios against a useful range of load forecasts raises questions regarding the reliability of 2024 IRP modeling for use in supporting near-term CPCN requests. In addition, the Companies should follow recommendations in Staff's Report on the 2021 IRP report calling for "LG&E/KU [to] identify energy efficiency opportunities for large customers"[70], a topic not addressed in the 2024 IRP.[71]

B. Supply-Side Analysis

Without correct, up-to-date assumptions for supply resource capital costs, operating costs, and operational characteristics, IRP modeling cannot result in useful recommendations to guide the Commission's decision making. LG&E-KU's omissions and errors in selecting supply resource assumptions affect every scenario and every modeling run.

With regards to **Best Practice B.1. All-resource RFP**, the Companies failed to issue an up-to-date, all-resource RFP prior to initiating their IRP modeling process to establish real-world market availability and costs for each resource type. For **Best Practice B.2. Modeled resources**, LG&E-KU's IRP modeling selected resource plans based on artificial limits on the share of renewable energy and excluding solar-plus-storage as a supply-side resource available for selection in its resource expansion model. The Companies' modeling choices do not meet the standard of **Best Practice B.3. Regulatory costs.** Commission Staff instructed LG&E-KU to fully evaluate carbon risk in their scenario modeling by assigning a cost to carbon emissions. By failing to do so the Companies are exposing themselves to over-investment in new gas resources (including gas co-firing modifications) that may become stranded assets when environmental regulations are strengthened. The Companies miss the mark on **Best Practice B.4. Fuel prices** by inventing a novel and erroneous method for forecasting coal prices. The Companies' methods for estimating resource costs also deviate from **Best Practice B.5. Technology costs** with the result that resource costs are overestimated in the medium- and long-run. LG&E-KU's failure to verify that its technology costs are reasonable and up-to-date undermines the reliability of its IRP recommendations.

Best Practice B.1. All-resource RFP: Conduct a competitive, all-resource request-for-proposals (RFP) for new resources based on real-world market availability and costs and provide bid results.

Overview: LG&E-KU did not conduct an up-to-date, all-resource RFP to inform their 2024 IRP modeling process.

LG&E-KU practices

Since their last IRP in 2021, LG&E-KU issued two RFPs for energy and/or capacity resources:

- **June 22, 2022 RFP:** For additions no earlier than 2025 to address potential environmental regulations, load growth, and unit retirements as well as to diversify the Companies' generation portfolio. Resource types were limited to "cost-effective firm peaking (including storage), intermittent non-firm renewable (with or without storage), and/or firm dispatchable baseload and load-following capacity and energy."[72]
- **May 1, 2024 RFP:** For additions no earlier than 2026 to address potential environmental regulations,

[70] Staff's Report on 2021 IRP, p.68.

[71] 2024 IRP, Response to JI-1 Question No. 50.; 2024 IRP, Response to SC-1 Question No. 12(e).

[72] 2024 IRP, Attachment 1 in Response to JI-1 Question No. 5.

load growth, and unit retirements as well as to diversify the Companies' generation portfolio. Resource types were limited to renewable energy resources such as solar, wind, or hydro resources via purchase power agreements (PPAs), asset purchases, or build transfers, but excluded capacity resources such as energy storage.[73]

Review

LG&E-KU's 2022 RFP was open to all resource types, aligning with best practice. However, the bids received in response to the latest all-resource RFP—and the quoted costs of resources—are now more than two years out of date. With substantial changes in resource costs over time,[74] two-year-old prices do not reflect current market conditions.

Recommendations

The Companies should issue an up-to-date, all-resource RFP prior to initiating their IRP modeling process to establish real-world market availability and costs for each resource type. LG&E-KU's last supply-side resource RFP was not successful, receiving (1) mostly solar project bids for which LG&E-KU entered into contracts for some projects that are now expected to be cancelled due to poor pricing estimates; and (2) no third-party thermal projects. Without changes to the RFP terms, future RFPs may also be unsuccessful. LG&E-KU would still be well-served to reform the RFP to avoid discouraging third parties from thinking their bids would ultimately be selected over self-build projects. For instance, a reformed RFP could allow third-party projects to assume an ability to build at existing interconnection points at utility-owned properties; and practically, in a reformed RFP process, LG&E-KU can take care not to prematurely submit its own self-build projects into its generator interconnection queue. If, even with improved RFP practices, limited information on real-world market availability and costs across resource types persist, it would then be reasonable for the Companies to review and present recent market cost and technology cost forecasts developed in neighboring jurisdictions.

Best Practice B.2. Modeled resources: Provide all supply- and demand-side resources available for model selection including operational characteristics and any limitations. Supply- and demand-side resources should be considered on a level playing field.

Overview: LG&E-KU's 2024 IRP considers several different supply- and demand-side resource additions, but imposes artificial limits on renewable energy resources and excludes utility-scale solar-plus-storage from consideration in modeling.

LG&E-KU practices

In their 2024 IRP, the Companies make several new supply- and demand-side resources available for model selection, including:[75]

- *"Fully dispatchable resources"*: Gas-fired, simple-cycle combustion turbines (SCCTs), natural gas combined cycle units (NGCCs), and small modular nuclear reactors (SMRs)

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[73] 2024 IRP, Attachment 2 in Response to JI-1 Question No. 5.

[74] Nat'l Renewable Energy Lab'y (NREL), 2024 Electricity Annual Technology Baseline (ATB) (July 2024), .https://atb.nrel.gov/electricity/2024/data. Available at: https://atb.nrel.gov/electricity/2024/data (available for download).

[75] 2024 IRP, Volume III. *Resource Assessment*. p.15

- *"Renewable energy resources"*: Land-based wind (located in Kentucky and Indiana) and utility-scale solar (located in Kentucky)
- *"Limited duration resources"*: 4- and 8-hour battery energy storage systems (BESS), dispatchable DSM program measures, and an expansion of the Companies' Curtailable Service Rider (CSR) program

In terms of resource availability, LG&E-KU assumes that SCCTs and NGCCs can be added no earlier than 2030, SMRs no earlier than 2039, and all other resources no earlier than 2028.[76] The Companies have also placed constraints on renewable energy resources by limiting solar generation to 20 percent of total energy requirements and the sum of solar and wind generation to 25 percent of total energy requirements.[77]

LG&E-KU does not consider the pairing of solar and storage resources (i.e., solar-plus-storage) for model selection.

Review

The Companies do consider several different supply- and demand-side resource additions in their IRP modeling and treat demand-side measures as equivalent resources in resource planning; however, not all potential supply-side resources were included in modeling. The Companies excluded solar-plus-storage, which pairs solar photovoltaics (PV) and energy storage technologies. The inclusion of solar resources and, separately, storage resources is not sufficient. Paired solar-plus-storage resources have unique costs and operational characteristics and must therefore be modeled as their own resource.[78]

The Companies' limitations on renewable energy resources are based on a faulty premise. The Companies' set their limitations using the findings of a 2023 publication in the journal *Energies*, which investigates the maximum amount of renewable energy resources that can be integrated into an existing resource portfolio in Kentucky without affecting the reliability of service.[79] The article's assessment, however, is based on an existing resource portfolio that is static in time and does not include any potential changes such as retirements or resource additions. In contrast, LG&E-KU's 2024 IRP modeling assesses a dynamic set of future scenarios and permits retirements of existing resources as well as resource additions.

LG&E-KU also takes the article's results out of context: The article goes on to discuss that higher integration of renewable energy resources can be achieved by increasing operational flexibility with the retirement of older coal-fired units that do not ramp up and down well as well as additions of utility-scale energy storage, demand response, and virtual power plants, among others.[80] The Companies' choice to hardcode constraints on renewables rather than allowing the model to make resource decisions based on costs and operational characteristics is unfounded. Optimization modeling should have been an opportunity to find a least-cost resource plan for LG&E-KU and not to use artificial limits from another source.

The Companies' artificial limitations on renewable energy investments were reached in 2035 or 2036 for all 24

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[76] 2024 IRP, Volume III. *Resource Assessment*. p.18

[77] 2024 IRP, Volume III. *Resource Assessment*. p.18

[78] Levelized Cost of Energy +, at pp. 37, 44. (June 2024), https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf.

[79] Donovin D. Lewis et al., *Decarbonization Analysis for Thermal Generation and Regionally Integrated Large-Scale Renewables Based on Minutely Optimal Dispatch with a Kentucky Case Study*, Energies (Feb. 17, 2023), https://engr.uky.edu/sites/default/files/PEIK/2023%20Energies%20UK%20SPARK%20Decarbonization%20Optimal%20Dispatch%20Regional%20Kentucky%20Author's%20Manuscript.pdf.

[80] *Id.* at pp.18-19.

high gas price resource plans as well as an additional four resource plans that include compliance with federal emissions standards (*see* Best Practice B.3).[81] Removing these constraints would allow the model to select the most cost-effective resources—including renewable resources—at all times.

In addition, the Companies neither include nor explain the exclusion of a key resource with benefits for resource plans: solar-plus-storage. Staff's Report on the 2021 IRP stated that the Companies should describe and discuss "if a resource was considered but ultimately not included in the resource expansion model. LG&E/KU should explain each basis for excluding the resource, including the specific information used to support each basis such as cost estimates that resulted in a resource being excluded as too expensive or engineering concerns that resulted in a resource being excluded based on a determination that it is not feasible."[82]

Recommendations

LG&E-KU should perform IRP modeling to generate resource plans without artificial limits on the share of energy requirements met by renewable energy under a full range of scenarios. The Companies should also include utility-scale solar-plus-storage as a supply-side resource available for selection in its resource expansion model. Modeling that is restricted in its choice of resource selection cannot be interpreted as producing least-cost plans or a reliable Recommended Resource Plan for use in near-term CPCN applications.

Best Practice B.3. Regulatory costs: Provide all regulatory costs modeled for existing and proposed resources (e.g., required environmental compliance equipment or emissions fees).

Overview: LG&E-KU considers several environmental regulations in their IRP modeling but fails to fully evaluate carbon risk in their scenarios, a serious omission that undermines the usefulness of their IRP recommendations.

LG&E-KU practices

In their 2024 IRP, the Companies considered several environmental regulations:

- *Ozone NAAQS (Good Neighbor Plan or GNP):* To comply with Ozone NAAQS, the Companies assume that selective catalytic reduction (SCR) will be needed to operate Ghent 2, a coal-fired power plant, in the ozone season beyond 2030, but could be needed as early as 2028.[83] Ghent 2 is the Companies' only remaining coal-fired power plant without SCR controls planned to continue operating beyond 2027.
- *Effluent Limitation Guidelines (ELG):* The 2024 ELG Rule establishes zero-discharge limits for flue gas desulfurization (FGD) wastewater, bottom ash transport water discharge (BATW), and combustion residual leachate (CRL) with a compliance deadline of as-soon-as-possible, but no later than December 31, 2029. In addition, the 2024 ELG Rule also imposes limits after April 30, 2035, on facilities that qualify for the new permanent cessation of coal combustion subcategory. In 2024, the Companies began installation and testing of new systems at their Ghent, Mill Creek, and Trimble County coal-fired units to establish biological treatment of FGD wastewater, which may require modifications or additions to comply with the 2024 ELG Rule, or as future environmental regulations go into effect. The Companies' Recommended Resource Plan complies with the 2024 ELG via zero liquid discharge at

[81] 2024 IRP, Response to SREA-1 Question No. 4.

[82] Staff's Report on 2021 IRP, pp.68-69.

[83] 2024 IRP, Volume I. p.5-26.

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Ghent and Trimble County in 2030 and by retiring Brown 3 and their remaining Mill Creek units by 2035.

- *Greenhouse Gas (GHG) Rule:* Adopted in 2024, the so-called GHG Rule establishes new source performance standards (NSPS) for new gas combustion turbines under section 111(b) of the Clean Air Act (CAA) as well as emissions guidelines for existing steam generators under CAA section 111(d). The GHG Rule requires coal-fired power plants to install equipment to reduce greenhouse gas emissions if their retirement is planned for after 2032.[84] Existing coal-fired units that plan to operate past 2039 must install carbon capture and storage (CCS) technology that captures 90 percent of carbon emissions by 2032.[85] Coal-fired units that commit to retire before 2039 (but after 2032) must achieve an emissions rate equivalent to 40 percent gas co-firing by 2030.[86] Out of these compliance pathways, the Companies' IRP modeling only includes the option to retrofit their existing coal-fired units to enable them to co-fire with natural gas. However, the Companies assign low likelihood to the scenario that evaluates the "GHG Rules as a carbon constraint"[87] claiming that EPA's compliance pathways are not achievable:

> *Although the EPA is obligated to set source performance standards, they must be achievable and adequately demonstrated. Among the standards are carbon capture transport and storage. There is no regulatory standard for storage wells or CO_2 pipelines in Kentucky, and implementing CO_2 transport or storage is not achievable on the GHG Rule's compliance timeline. Co-firing natural gas or full gas conversion are compliance alternatives for the GHG Rules; however, implementing additional natural gas transportation pipelines on the compliance timeline is questionable. Retiring generation is a compliance alternative for the GHG Rules, but retirements require reliable replacement capacity. Replacing generation at the scale necessary for compliance is not reasonable on the GHG Rules' timeline. Therefore, the Companies assign a low likelihood to this scenario.* [88]

Review

The Companies incorporate environmental regulations such as with Ozone NAAQS and ELG into their IRP modeling scenarios and assumptions. Best practices, however, require a fuller consideration of environmental regulations, particularly pertaining to climate risk. The Companies' treatment of the GHG Rule as "low likelihood" eliminates it from full consideration in identifying a least-cost plan, as discussed in Best Practice C.1 below. This modeling choice leads to an insufficient assessment of the implications of their resource decisions on the Companies' climate risks. Although the Companies' Recommended Resource Plan takes a "no regrets" approach supports the elimination from consideration of potential CO_2 regulation (as well as high economic development load growth), their modeling of the Recommended Resource Plan does not transparently demonstrate how the risk of future climate regulation was addressed.

[84] *See generally* 89 Fed. Reg. 39,798.

[85] U.S. Environmental Protection Agency (EPA), *Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants*. 89 Fed. Reg. at 39,838, (Apr. 25, 2024), Available at: https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf p.6.

[86] *Id.*

[87] 2024 IRP, Volume III. *Resource Assessment*. p.25. fn.45.

[88] 2024 IRP, Volume I. p.5-11

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The Companies present modeling a cost on CO_2 emissions versus GHG Rules compliance as an either/or decision, choose GHG Rules, and fail to consider those rules in their main modeling assessment or cost comparisons:

> *In past IRPs, the Companies placed a cost on CO_2 emissions in some scenarios to evaluate the risk of future CO_2 regulations. In this IRP, because the Companies evaluated compliance with the Greenhouse Gas Rules, they did not evaluate any scenarios with a CO_2 price.*[89]

The Companies' 2021 IRP claimed there was "no basis for assuming that a price on CO_2 emissions will or will not be [part of] any such regulations. For these reasons, the 2021 IRP does not evaluate resource expansion plans with an assumed price for CO_2 emissions."[90] Commission Staff responded by instructing the Companies to more fully account for the risks of carbon regulation or pricing, stating it "also believes that LG&E/KU's assessment of the potential impacts of carbon regulation should have been more robust."[91] Commission Staff also noted that even if climate regulations do not change during the 15-year planning horizon, risks in later years could impact resource decisions in the near term:

> *Commission Staff disagrees that projections beyond 2035 are beyond the scope of or irrelevant to the 2021 IRP, because projected useful lives of new generating units can affect the value of those units and projected useful lives of existing units can affect the value of upgrades necessary to keep those units operational.*[92]

Two other rules under the CAA are potentially impactful, but not fully evaluated by the Companies in their IRP modeling:

- *Mercury Air Toxics Standard (MATS) update:* Adopted in early 2024, the standard most importantly lowers the limit for particulate matter (PM, as a surrogate to be measured for heavy metals) from 0.030 to 0.010 pounds (lbs) per million British thermal units (MMBtu). The Companies say they are already monitoring compliance at all applicable units, but the rule will mean a tighter margin between emissions levels and the limit, meaning exceedances could happen more easily and there would be more difficulty with monitoring at such refined levels. Additional compliance measures such as control efficiency or monitoring upgrades were not modeled in any scenario.
- *Fine Particulate Matter ($PM_{2.5}$) NAAQS:* This standard was lowered from 12 to 9 micrograms per cubic meter ($\mu g/m^3$) effective May 6, 2024. The most recent data show only one monitor in the Louisville area exceeding the new standard. However, because EPA designates entire "Air Pollution Control Regions" based on the worst performing, or "design value," monitor in the region, the entire Louisville area could face a nonattainment designation. The designations process is ongoing, but a nonattainment designation could potentially come in early 2026, with attainment plans due late 2027, and a deadline to attain the standard likely being 2032. Like the ozone standard discussed in Companies' IRP, this means the Commonwealth and Louisville Air Pollution Control District will be responsible for driving

[89] *Id.* at p.5-12

[90] Case No. 2021-00393, LG&E-KU 2021 IRP Volume I, p.5-20, https://psc.ky.gov/pscecf/2021-00393/rick.lovekamp%40lge-ku.com/10192021013101/3-LGE_KU_2021_IRP-Volume_I.pdf.

[91] Staff's Report on 2021 IRP, p.61

[92] *Id.* at p.59

local reductions to achieve attainment, including requiring Reasonably Available Control Technologies and Reasonably Available Control Measures (RACT/RACM) no later than 2031. Again, Companies failed to take potential additional control measures into account and model for the possibility of additional control upgrades being required.

Recommendations

To comply with Commission Staff's 2021 instructions, the Companies should fully evaluate carbon risk in their scenario modeling by assigning a cost to carbon emissions. This scenario analysis should be directly and transparently included in the selection of a Recommended Resource Plan. Even though the fate of the current GHG Rule is uncertain, Commission Staff have instructed the Companies to consider carbon prices and climate regulations. A future without limits to greenhouse gas emissions is unlikely. By failing to take full consideration of expected regulatory and financial risk related to climate change, the Companies are exposing themselves to over-investment in new gas resources (including gas co-firing modifications) that may become stranded assets when environmental regulations are strengthened. Stranded assets are a serious financial risk to the Companies long-term viability and could result in increased customer rates to pay for unused infrastructure. Overall, this omission in LG&E-KU's modeling analysis results in IRP findings that cannot be relied upon to support near-term CPCN petitions.

Best Practice B.4. Fuel prices: Provide all fuel price projections used in modeling. Fuel prices should be based on recent well-verified sources and easily compared to publicly available sources.

Overview: LG&E-KU's gas prices generally conform with well-verified sources; their coal prices, however, are significantly outside of the range projected by respected sources.

LG&E-KU practices

As part of their 2024 IRP, LG&E-KU developed five fuel price profiles with gas prices as the primary price-setting factor and future coal prices estimated using historical coal-to-gas (CTG) price ratios:

- Low Gas, Mid CTG Ratio (LGMR)
- Mid Gas, Mid CTG Ratio (MGMR)
- High Gas, Mid CTG Ratio (HGMR)
- Low Gas, High CTG Ratio (LGHR)
- High Gas, Low CTG Ratio (HGLR)

LG&E-KU utilizes the U.S. Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO) Reference, High Oil and Gas Supply, and Low Oil and Gas Supply cases as the starting point for their mid, low, and high gas price forecasts, respectively.[93] The mid gas price forecast uses the average annual Henry Hub price from the NYMEX futures market for 2024 through 2027, then linearly interpolates from 2027 to the 2050 value from EIA's 2023 AEO Reference case forecast (*see* Figure 10 below). The low gas price forecast is the 2050 value from EIA's 2023 AEO High Oil and Gas Supply case deescalated for earlier years using the compound annual growth rate (CAGR) derived from the mid gas price forecast. The high price forecast interpolates between EIA's 2024 and 2050 values from the 2023 AEO Low Oil and Gas Supply case.

[93] 2024 IRP, Volume III. *Resource Assessment*. p.58.

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Figure 10. LG&E-KU's Gas Price Forecasts [BEGIN CONFIDENTIAL

[redacted] END CONFIDENTIAL]

Data source: LG&E-KU 2024 IRP Workpapers. Resource Planning. "CONFIDENTIAL 20240619_Natural_Gas_Forecast_2025BP.xlsx"

LG&E-KU develops their coal price forecasts as their gas price forecasts multiplied by historical CTG price ratios (*see* Figure 11 below). LG&E-KU's mid CTG ratio of 0.57 is the 10-year average of CTGs from 2012 to 2021.[94] The low and high CTG price ratios of 0.52 and 0.60 are the minimum and maximum, respectively, of the 6-year rolling average CTG price ratio from 2012 to 2021.[95]

[94] *Id.* at p.61.

[95] *Id.* at p.62.

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Figure 11. LG&E-KU Illinois Basin versus EIA's AEO Eastern Interior coal price forecasts [BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL]

Data sources: (1) 2024 IRP Workpapers. Resource Planning. "CONFIDENTIAL 20240712 2025 BP Coal Price Forecast.xlsx"; (2) U.S. EIA. March 2023. Annual Energy Outlook 2023. "Table 66. Coal Minemouth Prices by Region and Type." Available at: https://www.eia.gov/outlooks/aeo/tables_ref.php

Review

LG&E-KU's gas price forecasts are closely aligned with EIA and NYMEX expectations. While the Companies' MGMR fuel price profile conforms with AEO's Eastern Interior Reference case coal prices, their other four profiles are unrealistic, representing coal prices not anticipated in either the short or long run. The full range of all 19 coal prices forecasts modeled by AEO are shown in blue in Figure 11. LG&E-KU's method of forecasting coal prices as a function of gas prices and nothing more is both unconventional and frankly erroneous. The resulting HGMR, HGLR, LGHR, and LGMR coal price profiles are nonsensical.

And LG&E-KU has received this feedback before. An expert on behalf of the Kentucky Coal Association in Case No. 2022-00402 testified that:

> *The methodology ignores the fact that gas is a commodity that is effectively purchased real time while coal is purchased pursuant to a portfolio strategy which limits the impact of short-term gas price volatility.*[96]

[96] Case No. 2022-00402, Testimony of Emily Medine on Behalf of the Kentucky Coal Association, Inc., at p.41, https://psc.ky.gov/pscecf/2022-00402/mmalone%40hdmfirm.com/07142023055115/FINAL.mrm7.14esm.vr3_-_5.30_pm_-_REDACTED.pdf.

> *The Companies were asked multiple times as to the origin and justification for this policy and confirmed it was something they developed starting with this case and could identify no other party that employs this methodology.*[97]

LG&E-KU's bespoke method of coal price forecasts is unsupported analytically and unnecessary. To our knowledge, no other market participant uses this method. Nor is there reason to rely on price ratios relative to gas in light of readily available third-party forecasts based on broader market factors and influences over the near-, mid-, and long-term.

The effect is that HGMR and HGLR coal prices are unrealistically high, and LGHR and LGMR coal prices are unrealistically low. By instead choosing to lock the coal price forecast into a fixed position relative to gas prices, LG&E-KU invents a relationship between gas and coal prices that simply does not exist. The resulting prices are a fiction, as demonstrated by the lack of any similar coal price projections. Once again, the Companies' methods lead to time and money spent on modeling unrealistic future scenarios that are ultimately ignored in resource planning.

Notably, LG&E-KU also chose to explore their "atypical CTG Ratios" in contexts that would be relatively likely to favor gas generation. LG&E-KU did that by pairing—without explanation or justification—the high CTG Ratio with the low gas price forecasts—making for a relatively larger spread between coal and gas prices when gas prices are low—and pairing the low CTG Ratio with the high gas price forecast.

Recommendations

LG&E-KU should follow best practice by basing all fuel prices on recent well-verified sources that are easily compared to publicly available sources. We recommend coal prices taken from U.S. EIA resources such as the AEO. It is critical that IRP resource plans are evaluated across a reasonable range of future fuel prices to achieve recommendations that account for future price risks. Coal prices that are unreasonably low or high skew modeling results, impact resource plan composition, and, ultimately, have important, unpredictable effects on IRP recommendations.

Best Practice B.5. Technology costs: Provide all modeled costs for new and updated technology. Technology costs should be based on recent well-verified sources, easily comparable to publicly available sources, and inclusive of all available tax credits and/or other public incentives.

Overview: LG&E-KU uses a recent well-verified source as a basis for their capital cost forecasts but then modifies these costs using an erroneous method to adjust for short-term cost escalation and fails to evaluate technology cost uncertainty to assess a range of possible futures.

LG&E-KU practices

For new resource additions, LG&E-KU constructed long-term forecasts of capital costs based on the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline (ATB) "Moderate" scenario modified using recent technology cost estimates based on resources contemplated in the Companies' 2022 CPCN filing in

[97] *Id.* at p.39.

Case No. 2022-00402[98] (*see* Table 2).[99] These costs were escalated from 2022 CPCN but the method of escalation was not provided.[100]

Table 2. LG&E-KU's modified 2022 CPCN capital cost estimates

Resource	Technology	Year $	Capital Cost ($/kW)
SCCT	SCCT	2024	1,500
Brown 12	NGCC	2030	2,121
Mercer Co Solar	Solar	2026	2,108
Brown BESS	BESS	2026	2,160

Reproduced from LG&E-KU 2024 IRP Volume III. Technology Update. Table 10. p.25.

The 2024 IRP does not make it clear whether the 2022 CPCN capital cost estimates refer to assumptions in the Companies' original modeling, specific projects submitted in response the Companies' RFP, or ultimate pricing.

LG&E-KU modified NREL's 2024 ATB capital cost forecasts using what it calls an "inflation" factor. This factor combines two kinds of adjustments: (1) an annual inflation rate adjustment of 2.3 percent to convert NREL's 2022 dollars to nominal dollars;[101] and (2) a cost escalation rate bringing nominal NREL costs in line with LG&E-KU's capital costs for specific future years (shown in Table 2 above).[102] (In effect, the Companies are using the modified 2022 CPCN capital costs together with NREL CAGRs to convert to earlier and later years.) This escalation adjustment is substantial in scale, with values ranging from 32 to 59 percent, for resources included in their IRP modeling (*see* Table 3).

Table 3. LG&E-KU's inflation assumptions

	SCCT	NGCC	SMR	Solar	Wind	BESS
2023-2024	37.3%	32.4%	6.5%	59.0%	59.0%	37.5%
2025+	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%

Reproduced from 2024 IRP Volume III. Technology Update. Table 11. p.26.

Lacking a recent capital cost estimate for wind resources, the Companies utilized the implied escalation rate for solar to forecast wind capital costs.[103]

LG&E-KU also evaluated a solar cost sensitivity "where solar costs escalate from the beginning of the analysis period at 0.2 percent per year" instead of declining as predicted by NREL's 2024 ATB (*see* Figure 12 below).[104]

[98] Case No. 2022-00402, Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements, https://psc.ky.gov/case/viewcasefilings/2022-00402.

[99] 2024 IRP, Volume III. *Technology Update*. p.3.

[100] *Id.* at p.7, Tbl.4.

[101] *Id.* at p.26.

[102] *Id.* at p.26.

[103] *Id.* at p.6.

[104] *2024 IRP, Volume III. Resource Assessment.* pp.34-35.

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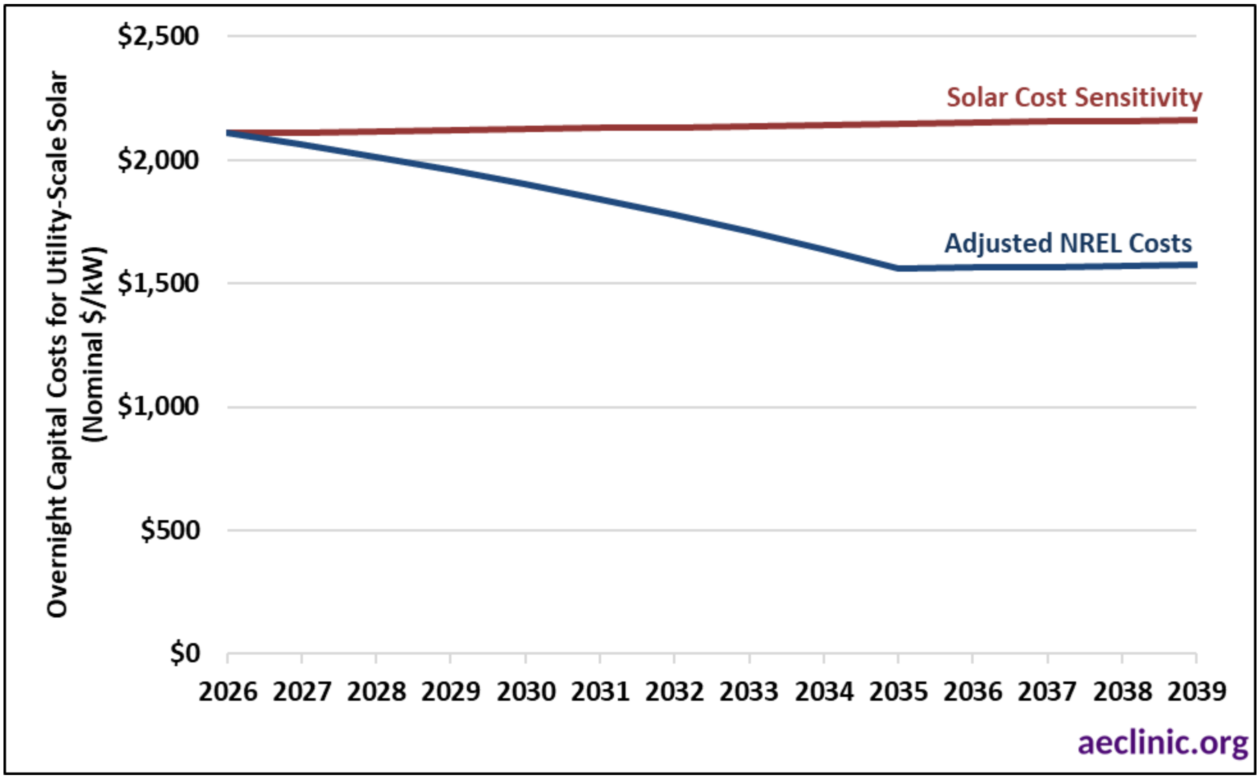
Figure 12. LG&E-KU's overnight capital costs for utility-scale solar



Note: These solar cost data are based on LG&E-KU's capital cost estimate for Mercer County Solar ($2,108 per kW, as shown in Table 2 above) escalated by the Companies' assumed nominal solar escalation rates for "NREL" and "Solar Cost Sensitivity". Source: (1) LG&E-KU IRP Volume III, Technology Update, Table 10, p.25; (2) LG&E-KU IRP Volume III, Resource Assessment, Table 16, p.35.

Review

LG&E-KU's methodology for constructing their technology cost forecasts partially aligns with best practices by using of a recent well-verified source—NREL's 2024 ATB—to develop their capital cost forecasts. Their modifications to those forecasts, however, are flawed due to their practice of carrying short-term cost increases into the later years causing forecasted costs in those years to be artificially high. The evaluation of a more expensive solar cost sensitivity—itself provided without citation or justification—in no way compensates for the use of erroneously inflated solar prices in all other scenarios.

Although LG&E-KU's attempt to align technology cost forecasts with their own recent cost estimates is not without justification, their methods conflate inflation with cost escalation. Inflation is an adjustment to the value of money (how much will a dollar buy in a particular year), whereas cost escalation represents changes in the market values of goods and services due primarily to changing supply conditions. The Companies' recent cost estimates appear to reflect temporary, short-term cost increases due in part to interconnection delays and/or supply chain issues.[105] However, LG&E-KU's treatment of temporary cost escalation as long-term

[105] U.S. Dep't of Energy, Tackling High Costs and Long Delays for Clean Energy Interconnection (May 11, 2023), https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection; Alicke, K. and T. Foster, *Supply chains: Still vulnerable*, McKinsey & Company (Oct. 14, 2024), https://www.mckinsey.com/capabilities/operations/our-insights/supply-chain-risk-survey.

inflation causes these cost increases to persist into the future and fails to contemplate a future in which capital costs return to "normal", which causes an artificial escalation of technology cost assumptions in later years.

The methodology that LG&E-KU employs to develop their technology costs has a significant impact on the resource decisions made by the model—not only affecting the selection of resource additions but also influencing retirement decisions. If the Companies' technology costs are artificially high for resource additions, this could cause the model to choose to keep uneconomic resources online longer than needed or select one resource when a different resource would be more cost effective for ratepayers. While the Companies do perform a technology cost sensitivity for solar resources, cost sensitivities for other resource types are not explored and no explanation is given for the choice of costs included in the solar sensitivity.

In addition, the Companies' decision to use their solar cost escalation to forecast wind resource costs is presented without justification. Temporary cost escalation experienced for one resource does not provide insight into the potential magnitude of cost escalation of another resource. Changes in historical solar and wind price are not well correlated.[106]

The Companies also failed to evaluate cost uncertainty in their technology cost forecasts by only leveraging NREL's 2024 ATB "Moderate" scenario instead of assessing a range of possible futures by including NREL's 2024 ATB "Conservative" and "Advanced" scenarios (*see* Best Practice C.7 for a discussion of uncertainty modeling). This omission exposes the Companies to risks of higher or lower technology costs and the potential for unplanned ratepayer costs.

Recommendations

When constructing their technology cost forecasts, the Companies should correctly model the implications of inflation versus those of cost escalation on the medium to long term. Adjusting capital cost forecasts to account for short-term cost escalation conforms with best practice; however, the Companies should more fully rely on the long-term protections developed by recent well-verified resources (such as NREL's 2024 ATB) and have capital costs return to "normal" in the medium term. The Companies should also evaluate cost uncertainty in their technology cost forecasts by assessing a range of possible futures, thereby providing a more robust assessment of the IRP modeling scenarios and reducing risk exposure.

To best estimate technology costs for all resource types (including wind), the Companies should have issued an up-to-date all-resource RFP (*see* description in Best Practice B.1 above) to establish real-world market availability and costs for each resource type. This is the first choice and best method.

In the absence of a recent all-resource RFP (or if insufficient bids are received for certain resources) the Companies should review and present recent market cost and technology cost forecasts developed in surrounding jurisdictions (*see* additional discussion in Best Practice B.1 above). LG&E-KU's failure to verify that its technology costs are a reasonable and up-to-date representation of actual market conditions undermines the reliability of its IRP recommendations.

[106] Lazard, Levelized Cost of Energy Analysis—Version 16.0, at p.9 (Apr. 2023), https://www.lazard.com/media/typdgxmm/lazards-lcoeplus-april-2023.pdf.

C. Modeling Structure

Scenario design and resource plan development are at the heart of every IRP's exploration of risks and uncertainties in planning supply resources to meet expected customer needs. LG&E-KU creates a lot of scenarios and conducts a lot of modeling but, in the end, it is all smoke and mirrors. Very little of the Companies' extensive modeling exercise is given any consideration in their design of a Recommended Resource Plan.

LG&E-KU's scenario modeling does not meet **Best Practice C.1. Future scenarios**. While many scenarios are modeled, very, very few are given any weight in selecting a Recommended Resource Plan. Regarding LG&E-KU's **Best Practice C.2. Scenario assumptions**, the Companies employ load, environmental regulation, fuel price, and technology cost assumptions that are based on erroneous methodologies and result in skewed projections of future assumption values. Poor construction of scenario assumptions cannot result in reliable least-cost planning. Similarly, the Companies' selection of a central case deviates from **Best Practice C.3. Base case**. LG&E-KU's base case fails to adequately represent key risks, and its IRP report fails to provide detailed comparisons of base case modeling results to their other scenarios' results. LG&E-KU's methods fall short of **Best Practice C.4. Resource portfolios** by excluding modeling of specified resource portfolios (the Recommended Resource Plan and other (hypothetical) plans requested by stakeholders) across a full range of future scenarios. The Companies' success in meeting **Best Practice C.5. Retirement analysis** is hampered by their failure to model carbon prices and choice to set artificial limits on renewable resource investments. Without unrestricted optimization of renewable resources, it is impossible to identify economic retirements. Presentation and accessibility limit the Companies' achievement of **Best Practice C.6. Optimization modeling**: Key quantitative modeling result comparisons should always be presented in the IRP itself, and detailed input and output files should be provided at the time of the IRPs release and not in response to later requests. Finally, the Companies' omit **Best Practice C.7. Uncertainty analysis** altogether by failing to conduct a stochastic analysis of key uncertain variables including fuel prices and technology costs.

Best Practice C.1. Future scenarios: Select a range of reasonable scenarios of the future exploring key uncertainties and risks (e.g., fuel prices or emissions fees) based on recent well-verified sources, easily comparable to publicly available sources.

Overview: LG&E-KU creates a broad range of scenarios but only considers a handful of these scenarios in their selection of a Recommended Resource Plan. Most scenarios are built on assumptions deemed unreasonable by the Companies and are discarded after modeling.

LG&E-KU's practices

LG&E-KU considered 60 future scenarios, based on every combination of three load profiles, four environmental profiles, and five fuel price profiles:

- **Load profiles:** low, mid, and high (*see* description in Best Practice A.1 above)
- **Environmental profiles:** no new regulations; Ozone NAAQS ("Good Neighbor Plan", or GNP); GNP+ELG; GNP+ELG+ GHG (*see* description in Best Practice B.3 above)
- **Fuel price profiles:** Low Gas, Mid CTG Ratio (LGMR); Mid Gas, Mid CTG Ratio (MGMR); and High Gas, Mid CTG Ratio (HGMR)—and two atypical CTG ratios—Low Gas, High CTG Ratio (LGHR); and High Gas, Low CTG Ratio (HGLR) (*see* description in Best Practice B.4 above)

In addition, a higher solar cost sensitivity of the mid load GNP+ELG profile is modeled for all five fuel price profiles.

Review

LG&E-KU creates a wide range of scenarios across three key uncertainties: load, environmental regulation, and fuel prices. However, as discussed below in more detail, while the Companies model all 65 scenarios the IRP does not give them equal consideration. Among the load profiles, low load is modeled but its resulting resource plans are not considered in the selection of a Recommended Resource Plan. The decision to exclude a low load future from planning is not justified in the IRP ("Based on current economic development activity, including data centers, the Companies assign a low likelihood to the Low forecast"[107]). If LG&E-KU is certain that some addition of MWs from data center additions will occur, then its low forecast is unreasonable and should instead have used a low but reasonable expectation. If, on the other hand, LG&E-KU considers zero additional MWs from data centers to be a reasonable future scenario, then these modeling results should have had a clear, and transparent, impact on the selection of the Recommended Resource Plan.

The high load forecast PLEXOS resource plans are considered as information in adjusting LG&E-KU's Recommended Resource Plan upwards but, among the high load PROSYM and Financial Model results, only the GNP+ELG scenarios appear to be irrelevant to the Companies resource planning. Instead of 65 scenarios, the Companies give full consideration to just ten: five mid load GNP+ELG scenarios using the solar cost sensitivity and five high load GNP+ELG scenarios.

While LG&E-KU ostensibly models four environmental regulation profiles, it rejects two as unlikely and gives limited consideration to another. The Companies designate their GNP+ELG environmental profiles as "most likely" stating: "Based on Environmental Protection Agency ("EPA") obligation, EPA authority, and a pragmatic evaluation of compliance technology implementation, the Companies consider this environmental scenario to be most likely."[108] Resource plans and Financial Model results for the no new regulation and GNP-only scenarios are not considered in the selection of a Recommended Resource Plan. The GNP+ELG+GHG PROSYM and Financial Model results appear to be irrelevant.

In addition, the Companies Recommended Resource Plan is developed using modeling results based on only one fuel price profile: Mid gas, Mid CTG (MGMR) (*see* discussion below in Best Practice D.4).[109] All scenarios that include their LGMR, HGMR, LGHR, and HGLR fuel price profiles are modeled but then discarded. Reasonable expectations regarding possible future fuel prices are a critical part of any IRP. Electric system modeling using higher and lower fuel price scenarios provides essential information regarding cost risks to ratepayers.

Instead, LG&E-KU rejects most modeled resource plans on an *a priori* basis that could have been (and possibly was) done before doing any modeling. This raises the question: Why run those other scenarios if they weren't going to inform the Companies' planning?

Recommendations

Modeling runs are expensive in both staff costs and run time; they are also critical to well-informed resource

[107] 2024 IRP, Volume I. p.5-15.

[108] 2024 IRP, Volume III. *Resource Assessment*. p.5

[109] 2024 IRP Workpapers. *Resource Planning*. "PROSYM."

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planning. To maximize efficient use of modeling resources, performative runs that serve no purpose in identifying a least-cost resource plan for ratepayers should be discouraged or, at a minimum, clearly identified as such. Modeling methodologies should be purposefully designed to reasonably balance efficiency and achieve broad weighing of uncertainties and trade-offs in a range of potential circumstances. Staff's Report on the 2021 IRP specified that "the Companies should include additional scenarios that compare and contrast assumptions, especially those that turn out to be primary drivers of modeling results and, hence, potential directions of future capital budgets and customer bill impacts."[110] Low and high sensitivities that are deemed unreasonable by the Companies or the Commissions should be replaced to provide a reasonable and useful range of possible futures that can better assure the selection of a least-cost resource plan for ratepayers.

Best Practice C.2. Scenario assumptions: Develop specific forecasted values to underly each of the designated future scenarios based on a reasonable range of predicted future values.

Overview: LG&E-KU scenario assumptions include serious omissions and errors.

LG&E-KU's practices

Scenario assumptions used in LG&E-KU's 2024 IRP are as follows:

- **Load profiles:** low, mid, and high (*see* review in Best Practice A.1 above)
- **Environmental profiles:**
    - *No new regulations:* no GNP, ELG or GHG regulations during the modeling period
    - *GNP:* "the Companies assume SCR will be needed to operate Ghent 2 in the ozone season (i.e., May through September) beyond 2030"
    - *GNP+ELG:* GNP plus "assumes the 2024 [Effluent Limit Guidelines] or its equivalent will also become effective"
    - *GNP+ELG+GHG:* GNP+ELG plus "the [Clean Air Act ("CAA") Section 111(b) and (d) Greenhouse Gas ("GHG") Rules] or their equivalents all become effective during the IRP planning period"[111] (*see* review in Best Practice B.3 above)
- **Fuel price profiles:** Low Gas, Mid CTG Ratio (LGMR); Mid Gas, Mid CTG Ratio (MGMR); and High Gas, Mid CTG Ratio (HGMR)—and two atypical CTG ratios—Low Gas, High CTG Ratio (LGHR); and High Gas, Low CTG Ratio (HGLR) (*see* description in Best Practice B.4 above)

Review

Serious concerns with data and assumption values used in the Companies' IRP modeling are presented in Best Practices A.1, B.3, and B.4 above: a failure to use a reasonable range of future load forecasts; a failure to consider existing and expected carbon regulations; and errors in the forecasting methods for coal prices. These omissions and errors undermine the Companies' resource plan designs and their exploration of risk surrounding the Recommended Resource Plan.

[110] Staff's Report on 2021 IRP, p.70

[111] 2024 IRP, Volume III. *Resource Assessment*. p.5

Recommendations

Resource plan design is only as good as the data and assumption values that goes into it. All data and assumption values should be documented and justified and should represent the range of reasonable expected future values. Poor construction of scenario assumptions cannot result in reliable least-cost planning.

Best Practice C.3. Base case: Identify one scenario as a base case or starting point to facilitate consistent comparisons across multiple future scenarios.

Overview: LG&E-KU identifies a base case but does not use it effectively to understand the impacts of key risks and uncertainties.

LG&E-KU's practices

In LG&E-KU's 2024 IRP, a "base case scenario" is selected as a starting point but it is also the ending point for scenario evaluation. As discussed in Best Practice C.1 above, only the five mid load GNP+ELG solar cost sensitivity and five high load GNP+ELG resource plans are given full consideration in cost evaluation. The mid load GNP+ELG MGMR solar cost sensitivity resource plan becomes the basis on which the Companies design their Recommended Resource Plan with hardcoded additions; the other four mid load GNP+ELG solar cost sensitivity resource plans are eliminated using a procedure discussed below in Best Practice D.4.

Review

The purpose of a base case in long-term utility modeling is to facilitate comparisons across multiple future scenarios. A base case creates a starting point that reflects a realistic or most likely view of the future (which complies with all existing laws and regulations) such that all other scenarios and sensitivities that deviate from that can be compared to easily draw conclusions on how different assumptions impact the modeling results. As discussed above in Best Practice C.1, LG&E-KU's selection of the mid load GNP+ELG MGMR solar cost sensitivity scenario as a base case fails to consider key risks from low load and existing and expected climate regulations.

Recommendations

LG&E-KU should select a base case for their 2024 IRP that adequately represents key risks and should provide detailed comparisons of base case modeling results to their other scenarios' results. Failure to select an appropriate base case undermines the reliability of IRP recommendations.

Best Practice C.4. Resource portfolios: Model and provide multiple options of portfolios of resources, retirements and limitations.

Overview: LG&E-KU successfully uses least-cost optimization modeling to identify least-cost resource plans but fails to optimize within distinct predetermined resource portfolios that could illuminate questions of policy or address financial risks related to key uncertainties.

LG&E-KU's practices

LG&E-KU uses the PLEXOS resource expansion model to consider new supply-side and demand-side resource options that include: the addition of a scrubber to Ghent 2; conversion of coal generating units to co-fire or burn 100 percent gas; and certain CPCN-approved resources[112] including the Brown Battery Energy Storage System, Mercer County Solar, Marion County Solar, and demand response plans from the 2024-2030 DSM-EE Program Plan.[113] PLEXOS is run with 65 scenarios to provide 65 resource plans (as described above in Best Practice C.1). These plans are developed not from distinct predetermined resource portfolios (or suites of resource options) but rather from least-cost optimization in the context of each scenario.

Review

Utility practices vary on the choice of running unfettered optimization models versus optimizing within predetermined portfolio limitations, with pros and cons to both methods. Unrestricted least-cost optimization—as in LG&E-KU's 2024 IRP—permits a full consideration of all possible resource options, without predetermination by modelers. In contrast, optimizing within predetermined portfolio limitations permits a systematic exploration of specific resource pathways and can offer more transparency in plan selection. As discussed in Best Practice D.4 below, transparency in plan selection is an area in which this IRP differs from best practice.

The Companies modeling runs are almost unfettered, imposing the following very basic, commonly used constraints on all 65 of their resource plans and otherwise leaving them (mostly) open to optimization: (1) reserve margins, (2) legislative unit retirement restrictions, (3) landfill storage capacity, and (4) technology availability. Importantly, as discussed in Best Practice B.2 above, LG&E-KU also imposes problematic artificial limitations on the amount of renewable energy investments permitted as a share of energy requirements. The Companies' choice to hardcode constraints on renewables rather than allowing the model to make resource decisions based on costs and operational characteristics is unfounded. Removing these constraints would allow the model to select the most cost-effective resources—including renewable resources—at all times. Once the modeled reached those renewable limits—which it did in nearly half of runs—it was left with a narrower set of selectable resources.

Recommendations

A combination of both modeling practices (unfettered optimization and optimization within predetermined portfolio limitations) is recommended to get the greatest benefit from resource portfolio design. To achieve this, LG&E-KU should work with stakeholders to define potential resource portfolios that would be useful in illuminating questions of policy or addressing financial risks related to key uncertainties. The Companies would then run PLEXOS with each of those resource specifications under all future scenarios. Their failure to explore their Recommended Resource Plan under the full range of developed scenarios is a serious gap in the usefulness of their findings and recommendations (*see* Best Practice D.4 below).

Best Practice C.5. Retirement analysis: Conduct and provide a retirement analysis to evaluate whether existing resources could retire earlier on an economic basis (rather than solely evaluating fixed retirement dates) that includes an assessment of avoidable, forward-looking costs.

Overview: LG&E-KU permits all coal units to be retired on an economic basis in their modeling, but provides

[112] The Companies' 2024 IRP modeling does not include six already-approved solar PPA projects, as explained at footnote 34, page 5-28 of 2024 IRP Volume I: "Of the six total solar PPAs," three have been canceled or terminated, and the Companies view the "remaining three PPAs" as "unlikely to proceed under their approved terms."
[113] 2024 IRP, Volume III. *Resource Assessment*. p.5

only a limited assessment of avoidable, forward-looking costs.

LG&E-KU's practices

LG&E-KU's stand-alone retirement analysis considers seven unit retirements and 17 replacements starting in 2030.[114] In addition, the Companies' resource expansion modeling made all coal units' retirement available for selection under all scenarios: "For the 2024 IRP, at the Commission's request, the Companies configured PLEXOS to evaluate the economics of all coal unit retirements."[115] All resource plans have pre-determined retirements of Mill Creek Unit 1 and Mill Creek Unit 2; the Recommended Resource Plan also includes a hardcoded deferred retirement of Brown 3 to 2035.[116] The optimized resource plans that the Companies used to inform the Recommended Resource Plan would retire Brown 3 in 2030 or 2031.

The Companies' separate retirement analysis identifies transmission upgrades necessary to accommodate seven retirement and replacement scenarios beginning in 2030 and extending to 2066. The cost of each scenario, and in some cases, the cost of each additional replacement unit, is considered. Collectively, these scenarios evaluate the retirements of Brown 3, Ghent 1, Ghent 2, Ghent 3, Ghent 4, Mill Creek 3, Mill Creek 4, Trimble County 1, and Trimble County 2. In all cases, the replacements are assumed to be NGCC generators. In addition, multiple scenarios of ten-year summer and winter peak demand, including 50/50 and 90/10 scenarios (e.g., 90 percent probability that load is higher than forecast and 10 percent chance that load is lower than forecast) are analyzed. The cost of voltage, transmission lines, and subs are estimated for each project type.[117]

Review

The Companies' modeling permits all coal units to be retired on an economic basis. Conducting a retirement analysis to identify uneconomic generating units is especially pertinent given the additional reporting procedures required by Kentucky state law (i.e., KRS § 278.264 and KRS § 164.2807). By conducting a comprehensive retirement analysis early on, the Companies would be able to initiate appropriate reporting procedures in a timely manner rather than delaying the process and creating unnecessary costs to ratepayers. The lack of scenarios modeling a carbon price (*see* Best Practice B.3 above) and the limitations placed on the share of renewable resources permitted (*see* Best Practice B.2 above) are obstacles to achieving clear resource plan comparisons showing the comprehensive costs and risks associated with unit retirements.

Recommendations

LG&E-KU should model carbon prices and refrain from setting artificial limits on renewable resource investments to achieve the most transparent and comprehensive retirement analysis possible. Without unrestricted optimization of renewable resources, it is impossible to identify economic retirements and model a least-cost resource plan.

Best Practice C.6. Optimization modeling: Conduct and provide (at a minimum) input and output files of long-term, system-wide modeling optimizing for least-cost solutions (i.e., capacity expansion and production cost

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[114] 2024 IRP, Volume III. *Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System*. p.1

[115] 2024 IRP, Volume I. p.5-12.

[116] 2024 IRP, Volume III. *Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System*. p.3.; 2024 IRP, Response to JI-1 Question No. 34.

[117] 2024 IRP, Volume III. *Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System*.

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modeling). Allow the model to optimize resource additions and retirements but limit the use of hardcoded constraints on the model.

Overview: LG&E-KU's extensive optimization modeling results are not easily accessible and were not presented for a lay audience in the IRP report itself.

LG&E-KU's practices

LG&E-KU's 2024 IRP uses PLEXOS resource expansion modeling and PROSYM production cost modeling, supplemented by an Excel-based "Financial Model".[118] Input and output files were not made available together with the release of the IRP report but instead were provided only after a request was made during the informal technical conference held on November 12, 2024 (*see* more details in Best Practice E.2 below).

Review

The Companies perform long-term, system-wide least-cost optimization modeling to identify resource plans and detailed production cost modeling to estimate present value of revenue requirements (PVRR). However, these modeling results are reported primarily as lists of resource additions and retirement by year (*see* LG&E-KU's *Resource Assessment* in IRP Volume III on pages 29 through 48). Cost, generation, and emissions results were not made available in the IRP report itself.

Recommendations

The Companies' lack of transparency regarding their modeling outputs is concerning. Key quantitative modeling result comparisons should always be presented in the IRP itself, and detailed input and output files should be provided at the time of the IRPs release and not in response to a later request (*see* Best Practice E.2 for a discussion of appropriate sharing of data, analysis and findings in an IRP process). Key variables should be compared transparently in the IRP report itself using figures such as Figure 18 below (comparing revenue requirements across scenarios) and Figure 13 below comparing CO_2 emissions across scenarios. The Companies' modeled scenarios result in minimal reductions to greenhouse gas emissions. [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]

[118] 2024 IRP Workpapers. *Resource Planning*. "Financial Model."

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Figure 13. CO_2 emission results in 2039 for LG&E-KU's 2024 IRP [BEGIN CONFIDENTIAL

[redacted]

[END CONFIDENTIAL]

Note: Each column in the figure represents one of LG&E-KU's five generation scenarios (E01 through E05), which are organized in order from left to right (dark to light). Data source: LG&E-KU 2024 IRP Workpapers. Resource Planning. "PROSYM."

Best Practice C.7. Uncertainty analysis: Conduct and provide uncertainty analysis using stochastic modeling approaches (e.g., Monte Carlo) using the range of possible scenario assumption values considered.

Overview: LG&E-KU's 2024 IRP does not include stochastic modeling to explore future uncertainties in key variables, typically used to reveal potential financial risks and enable risk management.

LG&E-KU's practices

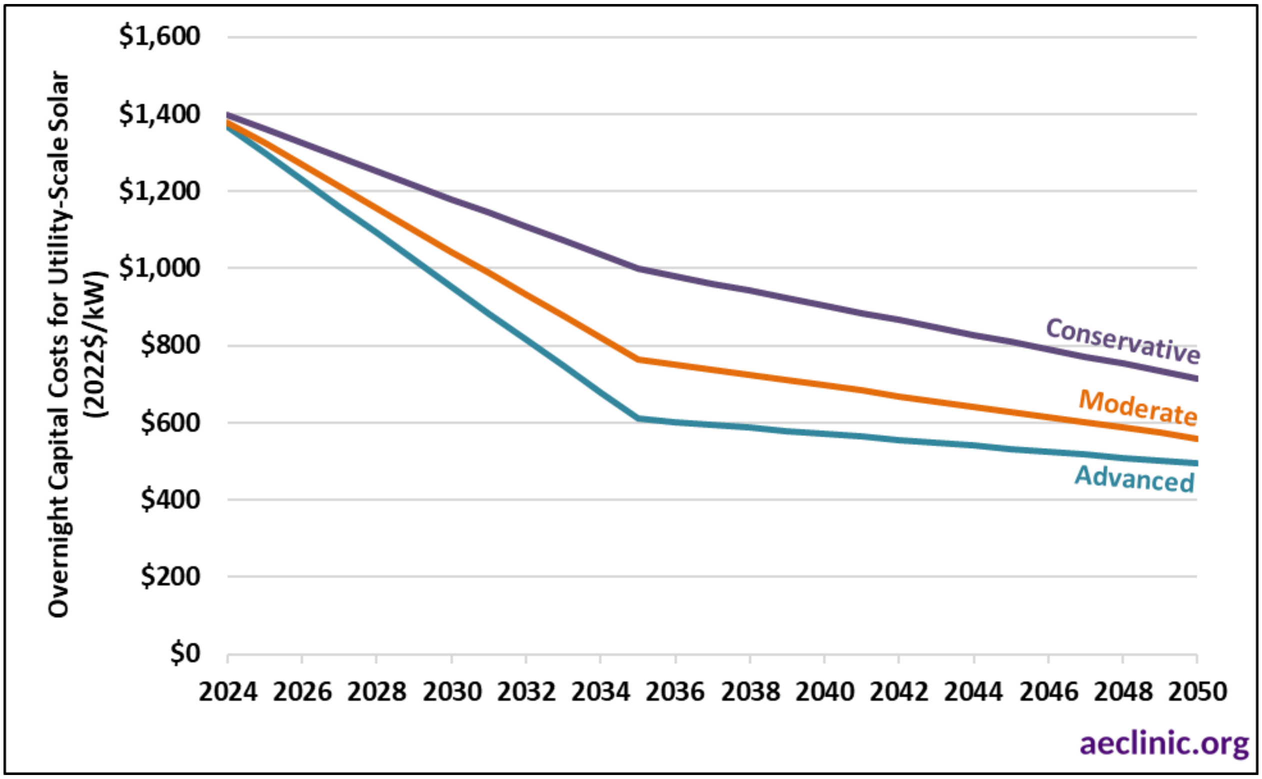
The LG&E-KU 2024 IRP does not include stochastic uncertainty analysis.

Review

The Companies create 65 future scenarios, develop 65 resource plans (plus modeling for an additional Recommended Resource Plan), and run 326 production cost modeling exercises deterministically. They do not, however, conduct uncertainty analysis (i.e. stochastic modeling) to explore future uncertainties. This is a critical component of thorough IRP modeling. This necessary exploration of the model's sensitivity to a full range of potential values for key uncertain variables is used to reveal potential financial risks, which would enable the Companies' ability to manage risks: "Having risk management be the primary focus of resource planning is consistent with safe and reliable service, which the Companies have the objective of providing at the lowest reasonable cost."[119]

In addition, the Companies' only inclusion of technology cost uncertainty is a solar cost sensitivity for which no explanation of assumptions was provided (*see* Best Practice B.5 above). NREL's ATB technology cost forecasts vary across three scenarios. As an example, Figure 14 shows NREL's forecasted uncertainty for future solar costs, with 2030 prices ranging from $953 to $1,180 per kW (in 2022 dollars), but LG&E-KU only explore the impacts of NREL's moderate technology costs and an unrelated, and undocumented, solar cost sensitivity.

Figure 14. Overnight capital costs (2022$/kW) for utility-scale solar from NREL's 2024 ATB



Data source: National Renewable Energy Laboratory (NREL). July 2024. "2024 Electricity Annual Technology Baseline (ATB)." Available at: https://atb.nrel.gov/electricity/2024/data

Recommendations

LG&E-KU's IRP modeling should include Monte Carlo analysis of key uncertain variables including fuel prices and technology costs. Without this type of thorough exploration of the Recommended Resource Plan's robustness to variable in assumption values across their full range, ratepayers are not protected from financial risks.

[119] 2024 IRP, Response to JI-1 Question No. 12(d).

D. Selection of Recommended Plan

LG&E-KU's 2024 IRP modeling methodologies cannot lead to the selection of a risk-weighted least-cost plan unless it is by happenstance. The Companies create many resource plans but (with two exceptions) discard them without considering their findings in the construction of their Recommended Resource Plan. Cost comparisons were not presented or discussed in the IRP report and non-cost metrics were not evaluated.

LG&E-KU does not meet that standard set by **Best Practice D.1. NPV comparison.** The Companies calculate PVRR results but fail to compare them in their workpapers or present them in the IRP report. No scorecard evaluation on non-cost metrics is performed as called for in **Best Practice D.2. Scorecard evaluation** and **Best Practice D.3. Quantitative assessment.** The Companies' methodology for selecting a Recommended Resource Plan also fails to meet the **Best Practice D.4. Recommended plan** standard. Their Recommended Resource Plan was created without consideration of the modeled findings across the range of potential future loads, environmental regulations or fuel prices.

Best Practice D.1. NPV comparison: Include in recommended plan selection (at a minimum) consideration of the net present value (NPV) of system costs (or revenue requirements) of all modeling runs. Provide NPV system cost results for all portfolios modeled under all scenarios. Utilize optimization modeling to evaluate all portfolios against all scenarios with the goal of identifying a least-cost portfolio for ratepayers.

Overview: LG&E-KU's IRP is incomplete and unreasonable without a presentation of their Recommended Resource Plan's costs under a full set of load, environmental regulation, and fuel price profiles for the Commission's and stakeholders' review.

LG&E-KU practices

While LG&E-KU fails to provide a detailed description of its modeling and resource selection methodology in the 2024 IRP report, AEC's technical review of confidential modeling files revealed the following: The 2024 IRP analysis calculated PVRR results for 65 resource plans across 5 fuel price profiles. These PVRRs are provided as confidential workpapers and are not reported in the IRP itself. Modeling was conducted across 65 scenarios (varying load, environmental regulation, and fuel price profiles) to develop all resource plans but one: The Recommended Resource Plan, which was only modeled for one load profile (mid), one environmental profile (GNP+ELG), the solar cost sensitivity, and one fuel price profile (MGMR). Low load, no environmental regulation, GNP-only, and GNP+ELG+GHG scenarios were modeled but their resource plans and costs were not included in the development of the Recommended Resource Plan.[120] The consideration in Recommended Resource Plan development of GNP+ELG mid load solar cost sensitivity and high load scenarios was not transparent and not based on cost modeling.

Review

The Companies' PVRR results—the key cost comparison used in the 2024 IRP—are not presented transparently. These values are not included in the IRP report and are only provided as Confidential workpapers, which are not easily interpretable by a non-technical audience and available only through petitioning to intervene in the proceeding, signing a non-disclosure agreement (NDA), and being granted access to the data site hosted by the Companies. This omission is a serious obstacle to public review and understanding of the Companies' resource

[120] 2024 IRP Workpapers. *Resource Planning*. "Financial Model."; 2024 IRP, Response to KIUC-1 Question No. 3.

planning decisions and, ultimately, ratepayers' electric costs. The omission of PVRR results or comparisons is extremely unusual; we are not aware of any other example of a utility IRP that does not report these values in the public IRP report.

In addition, LG&E-KU's failure to evaluate their Recommended Resource Plan under the full range of load, environmental regulation, and fuel price profiles (much less perform a stochastic analysis of key uncertain variables as discussed above in Best Practice C.7) weakens the 2024 IRP planning exercise and leaves the recommended resource plan essentially untested. Whatever conditions do in fact arise over the next fifteen years, they are certain to depart from the assumptions tested in the single mid load, GNP+ELG, solar cost sensitivity, and MGMR scenario. The purpose of uncertainty and sensitivity analyses performed across a reasonable range of potential futures in IRP modeling is to support more informed judgments about relative portfolio risks. The Companies must test the performance of reasonable plan alternatives across a full range of future scenarios to develop a Recommended Resource Plan, and an IRP must publicly report the forecasted performance of the Recommended Resource Plan across those future scenarios in an accessible and comprehensible manner.

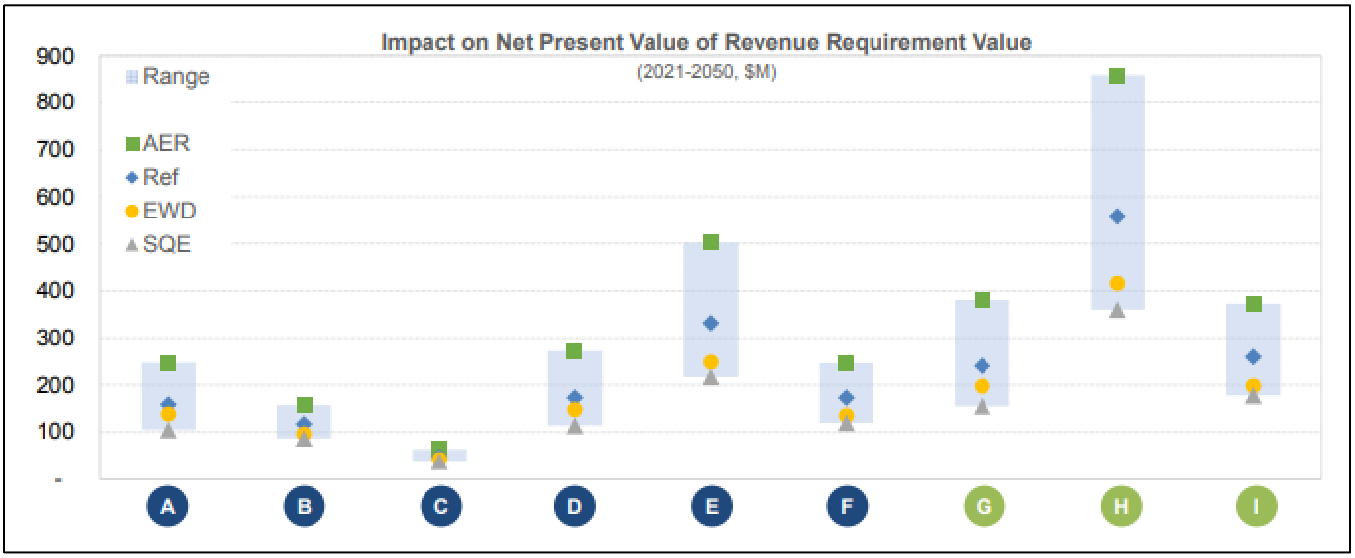
Finally, while LG&E-KU present most of the values required of electric utility's IRPs in 807 KAR 5:058 (PVRR in dollar terms, discount rate used in present value calculations, and annual average system rates are presented in the Companies workpapers) their annual revenue requirements are not provided, as required, in nominal and real terms.

Recommendations

LG&E-KU's 2024 IRP is incomplete and unreasonable. The Companies should provide and discuss PVRR results for their Recommended Resource Plan under all load, environmental regulation, and fuel price profiles. A thorough comparison of resource plan revenue requirements—as well as the costs of the Recommended Resource Plan under all Scenarios—should be presented and discussed in the IRP report itself. The Companies should make every effort to provide their cost comparisons and justification of their resource plan recommendations as transparently as possible. As one example, Northern Indiana Public Service Company's (NIPSCO) 2021 IRP provided a comparison of the PVRR results across its modeled scenarios (*see* Figure 15 below).[121]

[121] N. Ind. Pub. Serv. Co., 2021 Integrated Resource Plan, at p.246 (Nov. 2021), https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf.

Figure 15. Summary of PVRR results from NIPSCO's 2021 IRP



Source: Reproduced from Northern Indiana Public Service Company. November 2021. 2021 Integrated Resource Plan. Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf p.246

Best Practice D.2. Scorecard evaluation: Include in recommended plan selection a scorecard comparing all modeling runs on factors that are important to the Commission's decision-making, including NPV of system costs, emissions, reliability, cost exposure, market exposure, and job impacts, among other factors. Provide quantitative values for scorecard metrics results for all portfolios modeled under all scenarios along with clear evidence and justification for each metric.

Overview: LG&E-KU's 2024 IRP is incomplete and unreasonable without a comparison of non-cost factors that are important to the Commission's decision making, including emissions, reliability, cost exposure, market exposure, and job impacts.

LG&E-KU practices

LG&E-KU's 2024 IRP does not perform a scorecard evaluation; does not formally compare resource plans on any factors other than PVRR costs; provides a PVRR comparison across resource plans only within each environmental regulation profile (and not in the IRP report itself); does not discuss a comparison of PVRR costs across resource plans in their report; and does not provide quantitative metrics for non-cost evaluation criteria.

Review

The Companies' 2024 IRP lacks critical information necessary to select the best resource plan. Their evaluation of resource plans ignores emissions, reliability, cost exposure, market exposure, and job impacts, and focuses solely on a PVRR cost comparison that does not include financial risks. This is a serious flaw in LG&E-KU's 2024 IRP that calls into question the Companies' Recommended Resource Plan's expected impacts on ratepayers and utility in supporting resource proposals in near-term CPCN applications.

Recommendations

LG&E-KU's 2024 IRP is incomplete and unreasonable. The Companies should provide a comparison of resource plans using both cost and non-cost criteria. These findings—and their underlying assumption—should be made available to the Commission and stakeholders within the IRP report itself. For example, in its 2024 IRP, Duke Energy Indiana prepared a comprehensive scorecard (*see* Figure 16 below) that evaluated environmental sustainability, affordability, reliability, resilience, cost risk, market exposure, and execution risk among a variety of quantitative metrics (*see* more details on quantitative assessment in Best Practice D.3 below).[122] Without a scorecard comparison of resource plans across multiple criteria important information is lost and decision-making is made less transparent.

[122] Duke Energy Ind., 2024 Integrated Resource Plan, at p.130 (Nov. 2024), https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/2024-plan-and-attachments/vol-i-complete-2024-dei-irp-plan.pdf?rev=93f4e009ddfc44b0baa3f94f3e195b4a.

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Figure 16. Summary of portfolio scorecard results from Duke Indiana's 2024 IRP

Portfolio Scorecard			Convert/Co-Fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier (Stakeholder)
Environmental Sustainability	CO_2 Emissions Reduction	2035	74%	73%	70%	72%	74%	72%
		2044	91%	81%	81%	84%	88%	86%
	Cumulative CO_2 Reduction (Mt)	2044	367	340	337	348	367	362
	CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	2035	715	572	710	678	666	652
Affordability	PVRR ($B)	2044	$25.0	$23.6	$24.2	$24.3	$24.5	$24.3
	Customer Bill Impact (CAGR)	2030	3.9%	3.7%	3.9%	4.0%	4.0%	4.3%
		2035	3.1%	3.3%	2.8%	3.1%	2.9%	3.1%
Reliability	Fast Start Capability	2035	39%	31%	33%	33%	33%	38%
	Spinning Reserve Capability	2035	93%	93%	98%	102%	100%	87%
Resiliency	Resource Diversity (HHI)	2035	1766	3853	2802	2739	1758	2291
	Simulated EUE in 95th Percentile Cold Weather (Islanded System)	2035	2.8%	1.9%	0.9%	1.4%	2.1%	3.7%
Cost Risk	Cost Variability Across Scenarios ($B)	2044	$24.0-$28.1	$21.8-$26.8	$22.4-$27.2	$22.9-$26.9	$23.3-$27.8	$23.4-$27.2
	IRA Exposure	2030	81%	43%	81%	50%	49%	57%
		2035	81%	29%	20%	22%	33%	39%
Market Exposure	Fuel Market Exposure	Average	61%	72%	76%	72%	66%	70%
	Maximum Energy Market Exposure	Annual Max.	69%	43%	51%	53%	66%	52%
Execution Risk	Cumulative Resource Additions in MW	2030	1,037	1,656	1,037	1,856	1,831	2,181
		2035	1,823	5,568	4,049	4,149	2,686	4,105
	Cumulative Resource Additions as % of Current System	2030	13%	20%	13%	23%	23%	27%
		2035	22%	69%	50%	51%	33%	51%

Source: Reproduced from Duke Energy Ind., 2024 Integrated Resource Plan, at p.130 (Nov. 2024), https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/2024-plan-and-attachments/vol-i-complete-2024-dei-irp-plan.pdf?rev=93f4e009ddfc44b0baa3f94f3e195b4a.

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Best Practice D.3. Quantitative assessment: Evaluate scorecard metrics for use in recommended plan selection based on quantitative and cardinal values, and not qualitative assessment or ordinal ranking.

Overview: LG&E-KU's 2024 IRP includes neither a scorecard nor quantitative non-cost metrics.

LG&E-KU practices

LG&E-KU does not provide a scorecard (*see* Best Practice D.2 above) and, therefore, does not base scorecard metrics on quantitative assessment.

Review

IRP scorecard assessments are most transparent and relevant when based on quantitative metrics and not ranking or qualitative scores. LG&E-KU's 2024 IRP fails to provide this critical information, making it impossible to assess and compare modeled resource plans.

Recommendations

LG&E-KU's 2024 IRP is incomplete and unreasonable. The Companies should consider non-cost criteria in their resource plan recommendation and provide a transparent scorecard comparison using quantitative metrics. Although Duke Energy Indiana's 2024 IRP provided a comprehensive, quantitative assessment of key metrics in its portfolio scorecard, its 2021 IRP filing fell short on a few metrics and only provided qualitative scores (*see* Figure 17).[123]

Figure 17. Summary of portfolio scorecard results from Duke Indiana's 2021 IRP

				Reliability			Resilience / Stability			Affordability		Environmental Sustainability			Portfolio Flexibility
			METRIC	Dispatchable Resources as a percentage of load[1]	Can portfolio serve load in all years of IRP planning period?[2]	Average percentage of annual market purchases[3]	Diversity of Resources as measured by HHI[4]	Executability[5]	Can portfolio mix serve load in extreme weather weeks in PST?[6]	Average of portfolio PVRRs across scenarios[7]	5 year CAGR of rates in Ref Scenario w/o CO2[8]	2040 CO2 Reduction % and Avg Annual Tons Emitted[9]	On track for meeting Duke Energy Climate Goals?[10]	SO2, NOx, PM & Water Emissions[11]	Range of PVRRs across scenarios[12]
				Higher better	<.5% Acceptable	<20-25% preferred	Lower better			Lower better	Lower better	Greater reducton better			Smaller better
PORTFOLIOS	Optimized	1	Ref w/o CO2 Reg	115%	0.24%	25%	25%	●	●	$16.1	0.8%	-47%	No	◑	$3.6
		2	Ref w/ CO2 Reg	104%	0.36%	16%	25%	◕	◕	$16.1	0.8%	-74%	No	◕	$3.9
		3	High Gas Prices	117%	0.13%	31%	31%	●	●	$16.5	0.9%	-43%	No	◔	$4.2
		4	Low Gas Prices	118%	0.28%	15%	43%	●	●	$15.8	0.6%	-48%	No	◑	$4.9
	Hybrid	5	Balanced Hybrid	115%	0.06%	9%	19%	◕	◕	$17.5	1.4%	-40%	No	◔	$1.8
		6	Renewables/CC Hybrid	108%	0.08%	7%	15%	◑	●	$18.7	2.0%	-78%	Yes	◑	$2.0
		7	Renewables/CC/CT Hybrid	91%	0.23%	19%	17%	◕	◑	$18.0	1.3%	-78%	Yes	◑	$2.6
		8	Renewables/CT Hybrid	110%	0.05%	17%	18%	◑	●	$19.3	2.0%	-82%	Yes	◑	$2.3
	Stakeholder	9	Biden 100	102%	0.06%	12%	17%	◔	◕	$21.0	1.7%	-96%	Yes	◕	$1.3
		10	Biden 90	97%	0.26%	13%	17%	◔	◕	$20.0	1.5%	-90%	Yes	◕	$1.7
		11	Enviro Focused	84%	3.70%	41%	18%	◑	◑	$19.3	1.1%	-79%	Yes	◕	$3.8
		12	Reliable Energy	98%	0.08%	12%	19%	◑	◑	Note 13		-64%	No	◑	Note 13

○	◔	◑	◕	●
Poor	Fair	Good	Very Good	Excellent

Source: Reproduced from Duke Energy Indiana. December 2021. 2021 Duke Energy Integrated Resource Plan: Volume I. Available at: *https://www.in.gov/iurc/files/REVISED-PUBLIC-DUKE-ENERGY-INDIANA-2021-IRP-VOLUME-I.pdf* *p.109*

[123] Duke Energy Ind., 2021 Duke Energy Integrated Resource Plan: Volume I, at p.109 (Dec. 2021), https://www.in.gov/iurc/files/REVISED-PUBLIC-DUKE-ENERGY-INDIANA-2021-IRP-VOLUME-I.pdf.

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Best Practice D.4. Recommended plan: Select recommended plan from among the resource plans that were subject to modeling. In the event that an unmodeled resource plan is selected for recommendation, the company must run it through their modeling, evaluate it against the scorecard metrics (including the NPV of system costs) of the other resource plans, and provide that analysis.

Overview: LG&E-KU's 2024 IRP is incomplete and unreasonable without conducting appropriate modeling and, critically, including consideration of that modeling in the selection of a Recommended Resource Plan. The Companies' Recommended Resource Plan is modeled in PLEXOS and PROSYM but only under one scenario.

LG&E-KU practices

LG&E-KU selects their Recommended Resource Plan by choosing the scenario they find most likely (mid load GNP+ELG MGMR and solar cost sensitivity), adopting its associated resource plan, and then making several fixed resource additions based on a qualitative assessment of additional risks not represented in the mid load GNP+ELG MGMR scenario. Those additional hardcoded resources are:

- An SCR for Ghent 2
- 400 MW of battery storage accelerated to 2028
- Acceleration of a second NGCC to 2031
- Deferral of Brown 3 retirement to 2035
- 500 MW of solar is added in 2035 "after prices fall to hedge natural gas price volatility and future CO_2 regulation risk."[124]

The Recommended Resource Plan is modeled in PROSYM and evaluated in the Financial Model using only the MGMR fuel profile with no testing of portfolio performance under different loads, environmental regulations, solar costs, or fuel prices. In addition, the Companies introduce an unmodeled "Enhanced Solar" resource plan that is the Recommended Resource Plan with the addition of 1,000 MW of solar.

Review

The Companies selection of a Recommended Resource Plan (the mid load GNP+ELG MGMR with solar cost sensitivity resource plan plus the hardcoded additions listed above) is not based on consideration of findings from other scenarios (with the possible exception of the high load GNP+ELG MGMR scenarios) or a transparent evaluation of other criteria important to the Commission's decision making. Sixty-five scenarios are modeled. Two are given priority in consideration. One is chosen based on the modelers qualitative and undocumented assessment and then modified based on assumptions that are not presented transparently.

Sixty-three resource plans are created in PLEXOS but not used in the selection of the Recommended Resource Plan. An elaborate system evaluating those 63 resource plans across five fuel price profiles in PROSYM is implemented but not considered. PVRR costs are averaged to select one in every five resource portfolios as least cost in the Financial Model, but that assessment too is disregarded. A great deal of modeling—an expensive cost for ratepayers—is conducted but simply ignored. LG&E-KU could have run just the mid load GNP+ELG MGMR solar cost sensitivity in PLEXOS and just that same resource plan under the MGMR fuel price portfolio in PROSYM and the financial model and gotten exactly the same result.

While the Companies never present any comparison of PVRR costs across resource plans, AEC's PVRR comparison (shown in Figure 18 below) raises more questions than answers.

[124] 2024 IRP, Volume III. *Resource Assessment*. p.49

Figure 18. PVRR results for LG&E-KU's 2024 IRP [BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL]

Note: Each circle in the figure represents one of LG&E-KU's five generation scenarios (E01 through E05), which are organized in order from left to right (dark blue to light blue) and error bars on each circle represent the range of PVRR values across the five fuel price profiles. The GNP+ELG Mid Load Solar Sensitivity and High Load scenarios are triangles (instead of circles) and colored in magenta (rather than blue) to signify the resource plans that LG&E-KU utilized as bases for their Recommended Resource Plan. Data source: Kentucky Public Service Commission (KY PSC) Case No. 2024-00326. LG&E-KU 2024 IRP Workpapers. Resource Planning. "Financial Models."

Mysteriously, based on LG&E-KU's own modeling, the PVRR for their Recommended Resource Plan is [BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL]

Recommendations

LG&E-KU's 2024 IRP is incomplete and unreasonable. Their Recommended Resource Plan has been created without consideration of the modeled findings across the range of potential future loads, environmental regulations or fuel prices. No additional criteria for plan selection other than PVRR costs were presented. No stochastic uncertainty modeling was conducted. The Companies instead must conduct appropriate best-practice modeling to successfully present a complete 2024 IRP and assure least-cost planning for ratepayers. Without appropriate scenario development and modeling methods IRP planning cannot result in reliable recommendations that can be used in near-term CPCN applications.

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[125] 2024 IRP Workpapers. *Resource Planning*. "Financial Models."

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E. Stakeholder Input

Robust stakeholder input processes have the potential to streamline IRP development and improve the quality of its planning recommendations. LG&E-KU has not conducted any stakeholder process. Following **Best Practice E.1. Stakeholder process** would entail seeking input early in the IRP process, starting with assumptions before moving onto modeling results, and being open to adding portfolios and scenarios based on stakeholder recommendations. Following **Best Practice E.2. Transparency and accessibility** would entail providing necessary information and data together with the IRP report (and not later as a result of discovery requests) to allow the Commission, stakeholders, and technical experts to review and assess all aspects of the IRP process. To get the benefits of community feedback, modeling results need to be presented in the report itself in a way that is transparent and easy to understand for all stakeholders and not just technical experts.

Best Practice E.1. Stakeholder process: Facilitate a stakeholder process that seeks input early in the IRP process, starting with assumptions before moving onto modeling results. Be open to adding portfolios and scenarios based on stakeholder recommendations.

Overview: LG&E-KU did not seek stakeholder input in the development of their 2024 IRP.

LG&E-KU practices

LG&E-KU did not facilitate a stakeholder process in conjunction with filing their IRP with the Commission. Thus, stakeholders were unable to review the Companies' modeling assumptions in advance of modeling or preliminary results in advance of the report's filing. Nor were stakeholders permitted to provide recommendations for the Companies to consider in their modeling of IRP scenarios.

Review

Stakeholder processes provide interested parties with the opportunity to weigh in on the IRP process and provide input and recommendations for consideration by the electric utility. To follow best practice, electric utilities should engage with stakeholders early on and continue facilitating meetings on a regular basis throughout the IRP process to allow for meaningful feedback at key milestones in IRP development, including review of inputs and assumptions, examination of scenarios and modeling methodology, evaluation of preliminary results, and selection of a preferred portfolio. Stakeholder processes help foster transparency (*see* Best Practice E.2 below) and provide an opportunity for review and feedback from Commission staff and stakeholders third-party experts.

In response to a data request on this subject, the Companies explain that they do not participate in pre-filing stakeholder processes because the Companies do not believe that such stakeholder engagement is required by the regulation.[126] In the Companies' view, "the post-filing IRP process prescribed by the Commission's regulation *is* the stakeholder process."[127] Without offering a legal opinion, holding stakeholder processes in advance of IRP filings is a utility best practice, and the Companies are free to employ best practices in all their pursuits, including long-range integrated resource planning.

[126] 2024 IRP, Response to JI-2 Question No. 35.

[127] 2024 IRP, Response to JI-2 Question No. 35.

Recommendations

LG&E-KU should incorporate a stakeholder process as a key element in the development of their IRP to seek meaningful feedback from Commission staff and stakeholders who are directly impacted by the resulting resource decisions. LG&E-KU should ensure that stakeholder processes are not just performative to check off a box but rather are purposeful and promote a productive and open dialogue from developing assumptions to reviewing preliminary modeling results and weighing in on resource plan recommendations. This type of public, responsive process is employed by many utilities all around the United States simply because it works: More and earlier stakeholder dialogue leads to resource planning that can best meet ratepayers' needs including reliability and affordability.

Best Practice E.2. Transparency and accessibility: Provide necessary information and data (e.g., background materials on methods, data, and assumptions) together with the IRP report (and not later as a result of discovery requests) to allow the Commission, stakeholders, and technical experts to review and assess all aspects of the IRP process. Report modeling results in a way that is transparent and easy to understand.

Overview: LG&E-KU's modeling workpapers and results were neither transparent nor easily accessible.

LG&E-KU practices

Upon filing their IRP in October 2024 in Case No. 2024-00326, LG&E-KU submitted their IRP report volumes and appendices to PSC, and the public versions were made available through the Commission's file room. In lieu of submitting their load forecasting and resource planning workpapers at the time of filing their 2024 IRP, LG&E-KU filed a *Motion to Deviate*, noting that the file size exceeds the 50-megabyte filing limit of the Commission's E-Filing System:

> *The following non-confidential zip files are voluminous and exceed the 50 MB filing limit of the Commission's E-Filing System (collectively, "Large Files"):*
>
> *PSC Case No 2024-00326 -- LGE-KU 2024 IRP Load Forecasting Workpapers-- PUBLIC.zip*
>
> *PSC Case No 2024-00326 -- LGE-KU 2024 IRP Resource Planning Workpapers-- PUBLIC.zip*
>
> *The zip files listed above contain collections of smaller files in folder structures that are vital to their usefulness and comprehensibility, which necessitated filing them this way rather than as individual files.*[128]

The public workpapers were not made readily available to stakeholders until after a request was made during the informal technical conference held on November 12, 2024. LG&E-KU sent the links to these workpapers to intervening parties via email the following day to provide online access.[129] Intervening parties were granted access to all confidential filing materials through a data site hosted by the Companies after signing a non-disclosure agreement (NDA). Other interested parties were not given access to these IRP materials, some of which are provided publicly in other jurisdictions.

[128] 2024 IRP, Joint Motion for Approval to Deviate from Rule (Oct. 18, 2024), https://psc.ky.gov/pscecf/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/03-LGE_KU_2024IRP_Mtn_to_Deviate.pdf.

[129] Online access to public workpapers were sent out via email to intervening parties on November 13, 2024: (1) load forecasting workpapers (https://sko.filetransfers.net/downloadPublic/7112wtz9qibazuf), and (2) resource planning workpapers (https://sko.filetransfers.net/downloadPublic/3gu9o8t16ozihfx).

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Economic and Policy Analysis of Energy, Environment and Equity

Review

The Companies did not provide information and data necessary for the review of IRP assumptions and modeling together with (and at the time of submitting) their IRP report. Public workpapers were only made available by request and to intervenors. More complete confidential workpapers were only made available to intervenors after signing an NDA. These procedures limited access and delayed review. In addition, LG&E-KU's modeling results were not presented in a way that was transparent and easy to understand for non-technical experts. Indeed, on the whole, they were not presented in the IRP report at all. Direct IRP modeling experience and/or an advanced degree in economics should not be a limiting factor in stakeholders' ability to access and interpret basic IRP findings, including quantitative comparisons of key metrics across resource plans and scenarios.

The Commission has repeatedly emphasized the importance of the "principles of transparency regarding the evidence that the Commission relies upon in rendering its determinations."[130]

For instance, in setting the principles for determining the proper compensation to net metering customers, the Commission developed guiding principles based on the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM-DER"), including an emphasis on transparency:

> *Ensure transparency. Transparency creates trust between parties and allows for a robust public process around resource evaluation. All relevant assumptions, methodologies, and results from any party should therefore be clearly documented and available for stakeholder review and input.*[131]

The Commission went on to state:

> *While there may be instances in which confidential data provides insight or enables a superior methodological approach, the Commission encourages utilities and stakeholders to rely on public or third-party data to the extent possible. When two methodological approaches are provided in the record, one that relies on public and the other on confidential data, the Commission will have a strong preference for the method that relies on public data.*[132]

The Commission has followed this principle in several other cases since, both in setting rates and otherwise.[133] In 2023, the Commission addressed the issue of transparency of costs in LG&E-KU's most recent CPCN, again

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[130] KY PSC Case No. 2020-00064, *Elec. Application of Big Rivers Elec. Co. for Approval to Modify Its Mrsm Tariff, Cease Deferring Depreciation Expenses, Establish Regulatory Assets, Amortize Regulatory Assets, and Other Appropriate Relief*, Order at 7 (Jun. 30, 2020).

[131] KY PSC Case No. 2020-00174, *Elec. Application of Ky. Power Company for (1) a General Adjustment of Its Rates for Elec. Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Pub. Convenience and Necessity; And (5) All Other Required Approvals and Relief*, Order at 23 (May 14, 2021).

[132] *Id.* at note 72.

[133] KY PSC Case Nos. 2020-00349, *Elec. Application of Kentucky Util. Co. for an Adjustment of Its Elec. Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, and 2020-00350, *Elec. Application of Louisville Gas and Elec. Co. for an Adjustment of Its Elec. and Gas Rates, a Certificate of Pub. Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Order at 42 (Sep. 24, 2021); KY PSC Case No. 2022-00098, *Elec. 2022 Integrated Resource Plan of East Ky. Power Coop., Inc.*, Order at 41-42 (Mar. 09, 2023); KY PSC Case No. 2023-00413, *Elec. Application of Duke Energy Ky., Inc. For an Adjustment to Rider NM Rates and for Tariff Approval*, Order at 5-6.

erring on the side of transparency:

> *[T]he winning bids in the RFP responses and the avoided capacity costs are information that the Commission must be able to transparently address to provide the public with a meaningful cost-benefit analysis concurrently with reaching a decision in this matter.*[134]

Recommendations

LG&E-KU should submit all workpapers together with their IRP report, make greater efforts to make their workpapers publicly accessible, provide a clear presentation of their modeling results within their IRP report, and avoid over-designation of confidential materials (e.g., PVRR values do not warrant confidential protection). More, and sooner, stakeholder input and third-party expert review can only lead to better and more useful planning recommendations.

IV. Key Takeaways and Recommendations

AEC's exhaustive review of LG&E-KU's 2024 IRP found that its omissions and errors are an obstacle to providing reasonable results that make its conclusions useful in supporting a near-term CPCN. Overall, several key critiques emerge as the IRP's most serious failings:

- **Customer load is overestimated resulting in an exaggerated recommendation of necessary supply resources:** LG&E-KU underestimate the potential for energy savings measures (e.g., energy efficiency and demand-side management) in their load forecasts. The Companies' load forecasts are also dependent on assumptions related to behind-the-meter and demand additions that are not sufficiently justified and, in the case of data center growth, result in unprecedented growth in customer load.
- **Faulty resource costs and fuel prices obscure essential cost comparisons between resource plans:** LG&E-KU conflates inflation and cost escalation leading to overestimated resource costs in the medium- to long-run. The Companies' coal price forecasts are based on a novel and erroneous methodology that has been brought into question in the past.
- **Scenarios are modeled using unreasonable assumption value ranges and are not replaced with useful ranges to explore true risks:** LG&E-KU employ load, environmental regulation, fuel price, and technology cost assumptions that are based on erroneous methodologies and result in skewed projections of future assumption values leading to unreliable modeling results. The Companies err in modeling scenarios deemed unreasonable instead of creating new scenarios that are reasonable.
- **A preferred resource plan is selected without comparing costs across potential resource plans and without testing the preferred plan's sensitivity to alternative future scenarios:** Many resource plans are modeled but few are given any consideration in the design of the Recommended Resource Plan. Furthermore, a critical step in IRP modeling is omitted: The Recommended Resource Plan is never tested under the many future scenarios developed by the Companies.

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[134] KY PSC Case No. 2022-00402, *Elec. Joint Application of Ky. Util. Co. and Louisville Gas and Elec. Co. for Certificates of Pub. Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Order at 4 (Nov. 20, 2023).

- **No non-cost criteria are used in the selection of a preferred plan:** Unlike many if not most utility IRPs, LG&E-KU neglect to evaluate their resource plans using non-cost criteria like emissions, reliability, cost exposure, market exposure, and job impacts. Among the common criteria evaluated in IRP reports, only revenue requirements and CO_2 emissions are presented in LG&E-KU's workpapers. No metrics whatsoever are presented or compared in the Companies' report.
- **Stakeholder input was not considered in the development of the resource plans:** By failing to facilitate a stakeholder process in the development of their IRP, the Companies missed out on a chance to engage in dialogue with the Commission, customers, and community advocates. The voices of those most likely to be impacted by LG&E-KU's resource decisions were excluded from the IRP development process.
- **The IRP lacks a non-technical presentation of results demonstrating the Companies' plan selection process:** LG&E-KU's IRP modeling results need to be presented in the report itself in a way that is transparent and easy to understand for all stakeholders and not just technical experts. The Companies must make greater efforts to foster transparency and accessibility in their IRP filings by providing all necessary information and data together with the IRP report (and not later as a result of discovery requests) to allow the Commission, stakeholders, and technical experts a timely opportunity to review and assess all aspects of the IRP process.

The resulting LG&E-KU 2024 IRP is not a transparent presentation of resource plan development and selection, and its accompanying workpapers do not perform key comparisons necessary to justify the Recommended Resource Plan's selection. The revenue requirements of the Recommended Resource Plan are substantially lower than those of any other plan, without explanation. Rapid growth in customer demand stems from unreasonable and unsupported assumptions that LG&E-KU's territory will become home to a surprisingly large share of the nation's data centers. Uncertainty analysis to capture financial risks was not conducted, existing environmental regulations were ignored, and economic retirement of aging coal plants was thwarted by artificial limits on renewable energy investments. The flaws in the IRP are serious and consequential.

LG&E-KU's failure to follow IRP best practices results in adverse effects on ratepayers due to resource decisions that are not properly informed (or justified) by comprehensive IRP modeling best practices. One critical near-term effect of the IRP findings' lack of reliability is the influence it could have in supporting uneconomic resource additions in near-term CPCN applications. The Commission should set aside LG&E-KU's 2024 IRP for any use in CPCN filings and should set specific standards for future IRPs to follow best practices.

PPL CORPORATION

4th Quarter 2024 Investor Update

February 13, 2025

Cautionary Statements and Factors That May Affect Future Results

Statements made in this presentation about future operating results or other future events are forward-looking statements under the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from the forward-looking statements. A discussion of some of the factors that could cause actual results or events to vary is contained in the Appendix of this presentation and in PPL's SEC filings.

Management utilizes non-GAAP financial measures such as "earnings from ongoing operations" or "ongoing earnings" in this presentation. For additional information on non-GAAP financial measures and reconciliations to the appropriate GAAP measure, refer to the Appendix of this presentation and PPL's SEC filings.

Business Update

Vince Sorgi
President & Chief Executive Officer

4th QUARTER 2024
INVESTOR UPDATE

February 13, 2025

2024 Review

Delivering value for both customers and shareowners

- ✓ **Provided electricity and natural gas safely and reliably to our more than 3.5 million customers**
  - Achieved first quartile T&D reliability and first decile generation fleet performance [(1)(2)]
  - Increased vegetation management spend to improve reliability against more frequent and more severe storms
- ✓ **Achieved midpoint of our original 2024 earnings forecast of $1.69 per share**
  - In line with midpoint of 6% - 8% EPS growth target
  - Results were $0.01 per share below midpoint of updated 2024 forecast range of $1.70 per share due to mild weather and storm activity in late December
- ✓ **Executed $3.1 billion capital plan to support the delivery of safe, reliable and affordable energy**
  - Included installation of storm-hardened infrastructure, deployment of advanced meters, replacement of leak-prone pipe and began the transitioning of aging generation facilities
- ✓ **Achieved high end of our cumulative $120 - $130 million annual O&M savings target for 2024**
  - Realized ~$130 million in savings from 2021 baseline
- ✓ **Completed integration of Rhode Island Energy; exited TSA with National Grid**

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Reliability performance based on System Average Interruption Frequency Index (SAIFI), the average number of interruptions that a customer experiences over a specific period for each customer served.
(2) Generation performance based on Equivalent Forced Outage Rate (EFOR). Represents the number of hours a unit is forced offline, compared to the number of hours a unit is running.

Updated Business Plan Enhances Growth Outlook

Strengthening and extending growth targets through 2028

- **Announces 2025 EPS forecast range of $1.75 - $1.87 per share with a midpoint of $1.81 per share**
  - Midpoint represents over 7% growth off 2024 original forecast midpoint of $1.69 per share
- **Extends 6% - 8% annual EPS and dividend growth targets through at least 2028 (previously 2027)**
  - EPS growth CAGR through 2028 expected to be in top half of targeted growth rate range
  - Growth targets based off the 2025 forecast midpoint of $1.81 per share
- **Increases capital plan to $20 billion for 2025 – 2028 (vs. $14.3 billion 2024 – 2027)**
  - Results in rate base growth CAGR of 9.8%; strengthens predictability of meeting growth targets
- **Continue to target cumulative annual O&M savings of at least $175 million through 2026** (1)
  - Every $1 of O&M savings on average can be reinvested as $8 of capital without impacting customer bills
- **Maintains strong credit metrics throughout planning period**
  - Project $2.5 billion of equity needs through 2028 to support additional capex and 16% - 18% FFO/CFO to debt target
- **Announces ~6% increase to quarterly common stock dividend to $0.2725 per share**
  - At lower end of targeted dividend growth rate range given significant growth capital in updated plan

(1) Reflects annual O&M savings targets from 2021 baseline.

Strategic Update

Advancing progress in delivering our "Utility of the Future" strategy

PPL's "Utility of the Future" Strategy

Improve the reliability and resiliency of our electric and gas networks

Advance a cleaner energy future affordably and reliably

Deliver operational efficiencies to support customer affordability

Build scale, enable our strategy and drive sustainable growth

Empower customers through digital solutions and better customer service

How we are executing our strategy

- ✓ Restructured our business and realigned teams across PPL to best execute our strategy, implement best practices across our enterprise, increase operational efficiencies and drive continuous improvement
- ✓ Initiated IT transformation effort to move to common systems across PPL, including engaging with some of the world's leading technology companies to implement cutting-edge technology to the utility industry to deliver better outcomes and improved efficiency for our customers and employees
- ✓ Initiated execution of planned generation investments in Kentucky that will advance a reliable, affordable and cleaner energy mix, while supporting critical R&D for new, lower-carbon generation solutions (including carbon capture and energy storage)
- ✓ Developed common design and operations standards across our utilities, including more robust engineering and construction specifications to strengthen and automate the Grid and to mitigate increasing weather and storm risks, including risks of wildfires and flooding
- ✓ Supported economic development in the regions we serve and positioned our utilities to attract significant data center load and respond quickly to interconnection requests
- ✓ Engaging with key stakeholders to strengthen resource adequacy in PA/PJM

Regulatory Update

Advancing key regulatory proceedings in each of PPL's jurisdictions

Kentucky Updates

- Continue to advance IRP that was filed in Q4 2024; hearing scheduled for May 13, 2025 [(1)]
- Expect to file a Certificate of Public Convenience and Necessity (CPCN) in Q1 2025 to address near-term generation needs identified in IRP
- Expect to file a base rate case in KY in the first half of 2025; current stay out period ends July 1, 2025

Pennsylvania Updates

- Awaiting decision from PAPUC on pending DSIC waiver proceeding [(2)]
- Assessing timing of next base rate case

Rhode Island Updates

- Filed electric ISR plan in December requesting recovery of ~$260 million of certain electric infrastructure investments (including Advanced Meter Functionality investments) and vegetation management costs projected to be incurred from April 2025 through March 2026; decision expected by RIPUC by the end of March 2025 [(3)]
- Filed gas ISR plan in December requesting recovery of ~$225 million of certain gas infrastructure investments projected to be incurred from April 2025 through March 2026; decision expected by RIPUC by the end of March 2025 [(3)]
- Expect to file a base rate case in RI in Q4 2025; current stay out period ends October 1, 2025

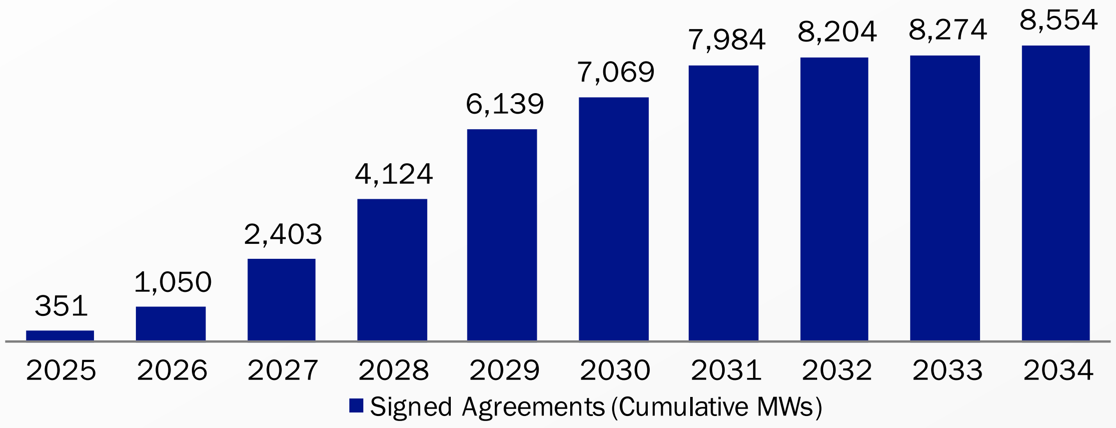
(1) IRP: Integrated Resource Plan. KY IRP filing docket: 2024-00326.
(2) DSIC: Distribution System Improvement Charge. PA DSIC waiver docket: P-2024-3048732.
(3) ISR: Infrastructure, Safety and Reliability. RI Fiscal Year 2026 ISR plan dockets: 24-54-EL and 24-54-NG.

Data Center Update

Pennsylvania and Kentucky continue to attract data center interest

PA Data Center Requests in Advanced Stages

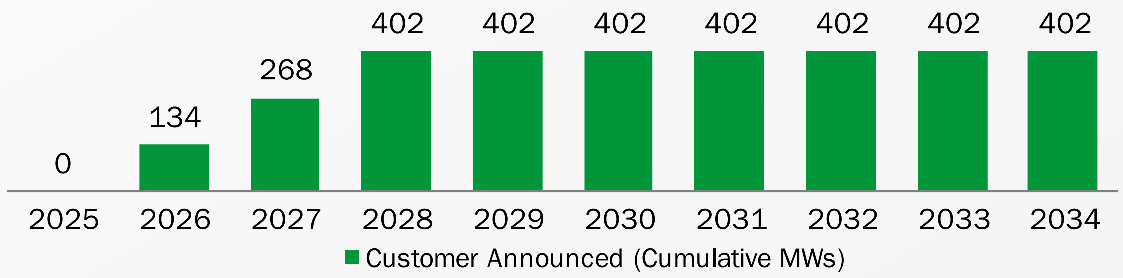
Requested Load In-Service Dates (in MW)



- ~9GW in advanced stages (up from 8GW) represents potential transmission capital investment of $600M - $700M; $400M reflected in updated capex plan(1)
- Active data center requests have increased to 48GW from 2026 – 2034
- Data center connections will lower transmission costs for retail customers as load ramps up(2)

KY Data Center Requests in Advanced Stages

Load Availability In-Service Dates (in MW)



- Announced Kentucky's first 400 MW hyperscale data center campus in Louisville
- Active data center requests have increased to nearly 6GW over 2026 – 2034 (up from 3GW)

(1) The data centers in advanced stages represent projects that have signed agreements with developers and costs being incurred are reimbursable by the developers if they do not move forward with the projects.
(2) Currently estimate that for the first 1GW of data center demand connected to the grid, our residential customers may save nearly 10% on the transmission portion of their bill, assuming $100M of network upgrades (~$3 per month). The percentage and amount of customer savings year-over-year will depend on several factors including timing of load ramp, amount of investments required and the peak load on our system.

Financial Update

Joe Bergstein
Executive Vice President & Chief Financial Officer

4th QUARTER 2024
INVESTOR UPDATE

February 13, 2025

Financial Overview

4th Quarter and full-year financial results

(Earnings per share)

	Q4 2024	Q4 2023
Reported Earnings (GAAP)	$0.24	$0.15
Less: Special Items	($0.10)	($0.25)
Ongoing Earnings	$0.34	$0.40
KY Regulated	$0.17	$0.17
PA Regulated	$0.20	$0.20
RI Regulated	$0.02	$0.05
Corp. and Other	($0.05)	($0.02)

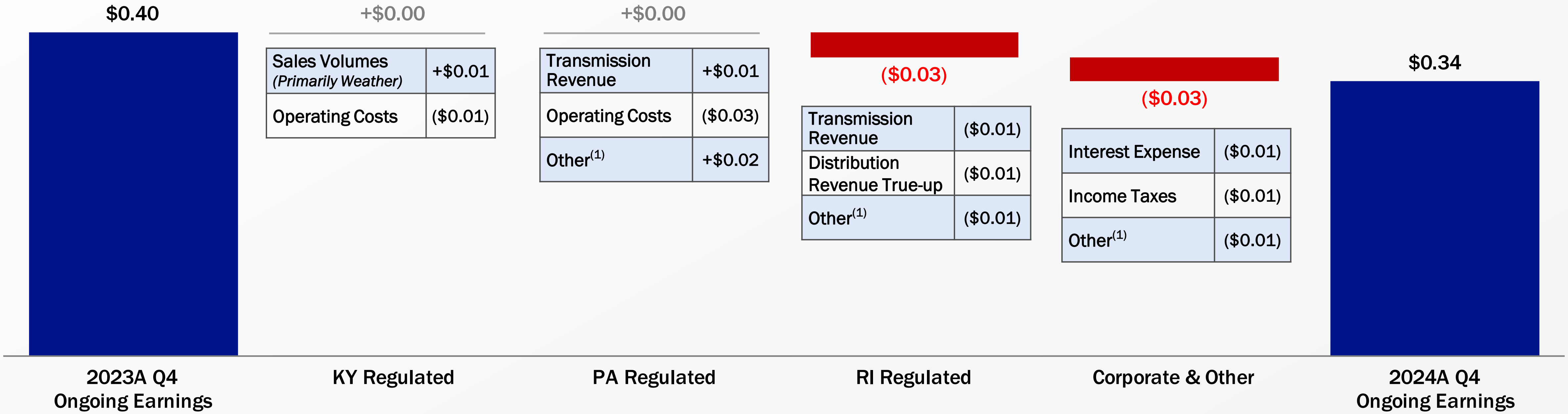
	2024	2023
Reported Earnings (GAAP)	$1.20	$1.00
Less: Special Items	($0.49)	($0.60)
Ongoing Earnings	$1.69	$1.60
KY Regulated	$0.84	$0.77
PA Regulated	$0.82	$0.74
RI Regulated	$0.21	$0.20
Corp. and Other	($0.18)	($0.11)

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

Review of 4th Quarter Financial Results

Ongoing Earnings Walk: Q4 2024 vs. Q4 2023

(Earnings per share)



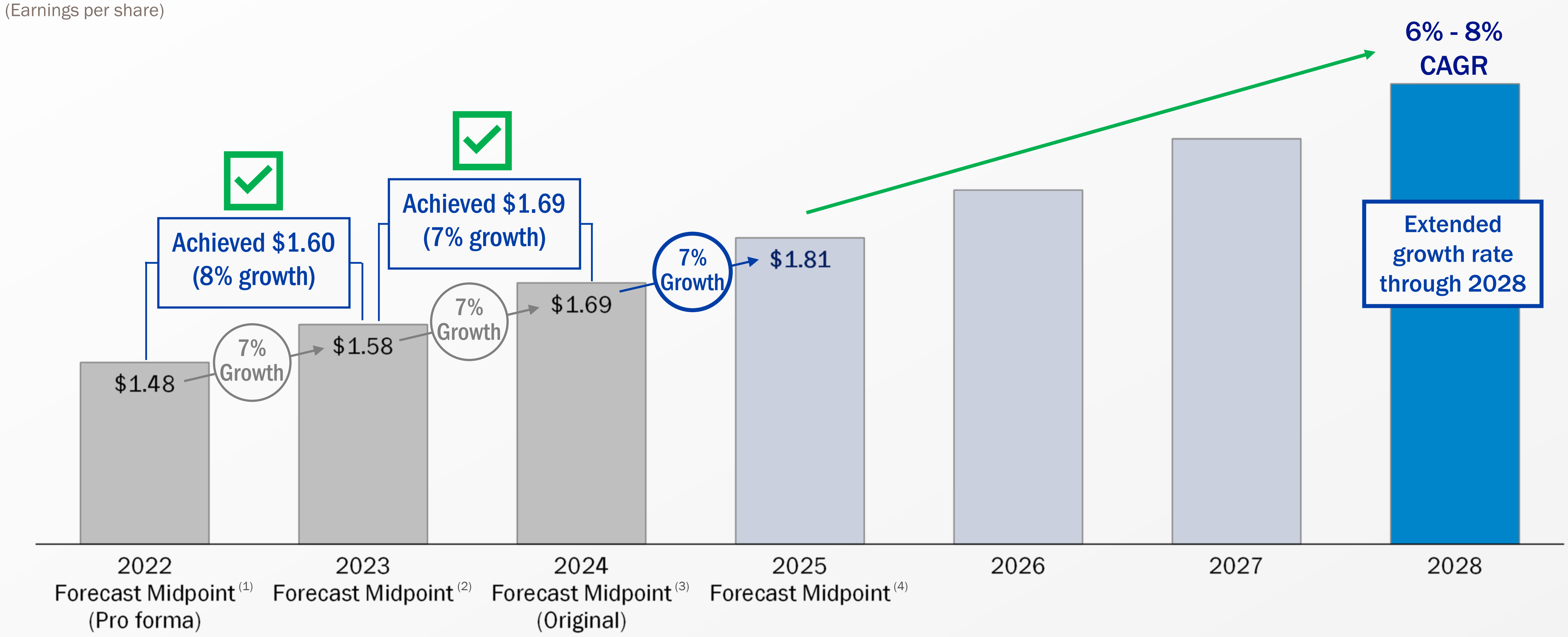
Segment	KY Regulated	PA Regulated	RI Regulated	Corporate & Other	Total PPL
2024 Q4 Ongoing EPS	$0.17	$0.20	$0.02	($0.05)	$0.34

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Reflects factors that were not individually significant and certain intercompany activities that eliminate in consolidation.

Delivering Strong, Sustainable Growth

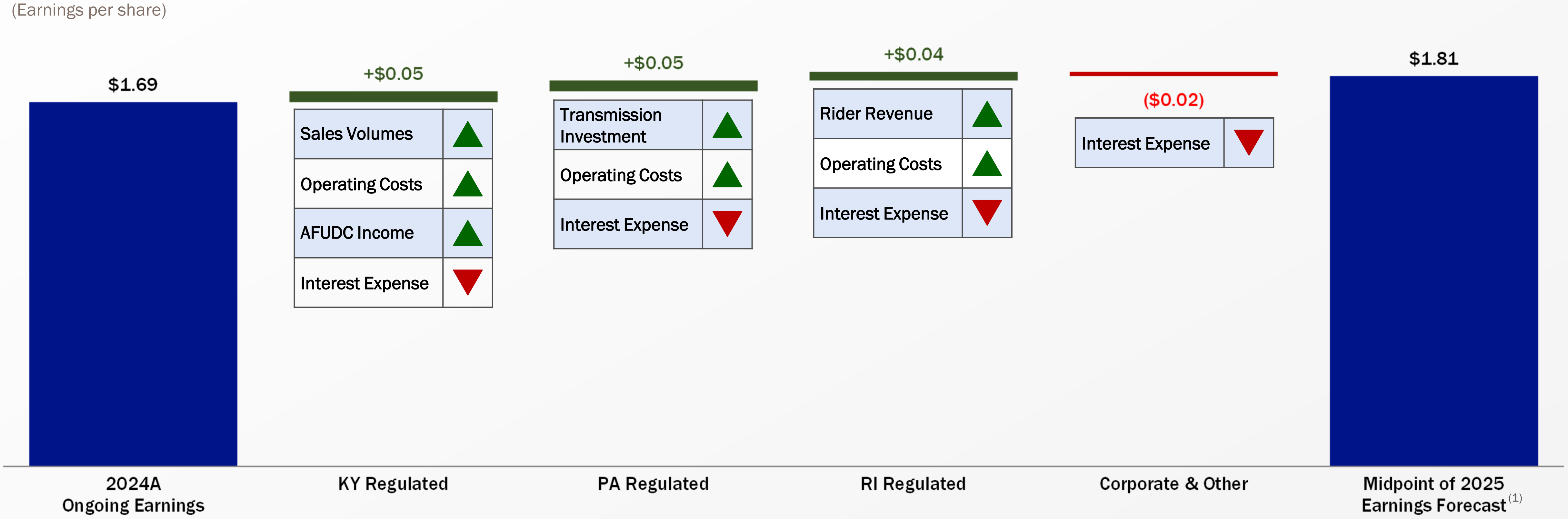
Achieved midpoint of growth target in 2024; extended growth through 2028



(1) Represents the midpoint of PPL's 2022 pro forma forecast range of $1.40 to $1.55 per share, reflecting a full year of earnings contributions from Rhode Island Energy (RIE). RIE was acquired by PPL in May 2022.
(2) Represents the midpoint of PPL's 2023 forecast range of $1.50 - $1.65 per share.
(3) Represents the midpoint of PPL's 2024 original forecast range of $1.63 - $1.75 per share. Updated forecast range to $1.67 - $1.73 per share in November 2024.
(4) Represents the midpoint of PPL's 2025 forecast range of $1.75 - $1.87 per share.

Walk to Midpoint of 2025 Earnings Forecast

Projected drivers of annual ongoing EPS growth



Segment	KY Regulated	PA Regulated	RI Regulated	Corp. & Other	Total PPL
2025 EPS Forecast[1]	$0.89	$0.87	$0.25	($0.20)	$1.81

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

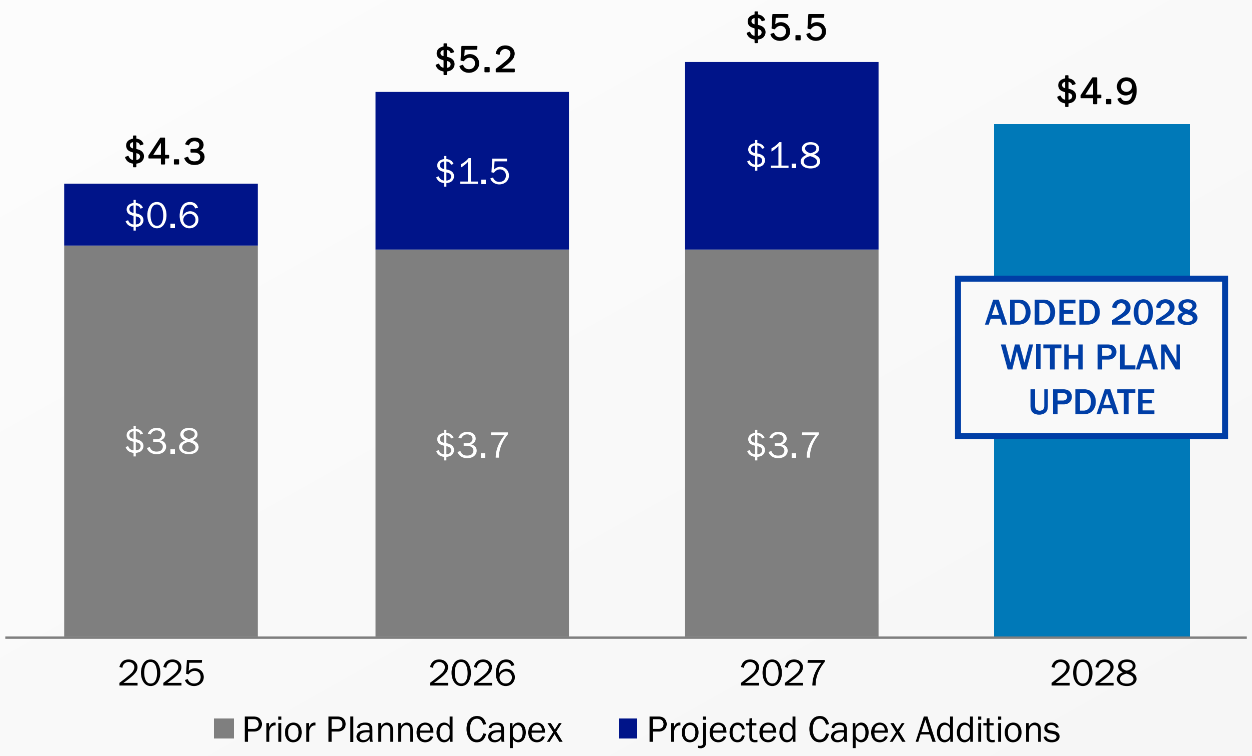
(1) Represents the midpoint of PPL's 2025 earnings forecast range of $1.75 - $1.87 per share.

2025 – 2028 Capital Investment Plan

$20B capex plan to enable the delivery of safe, reliable and affordable energy

($ in billions)

Plan is $5.7 billion higher than prior 4-year plan



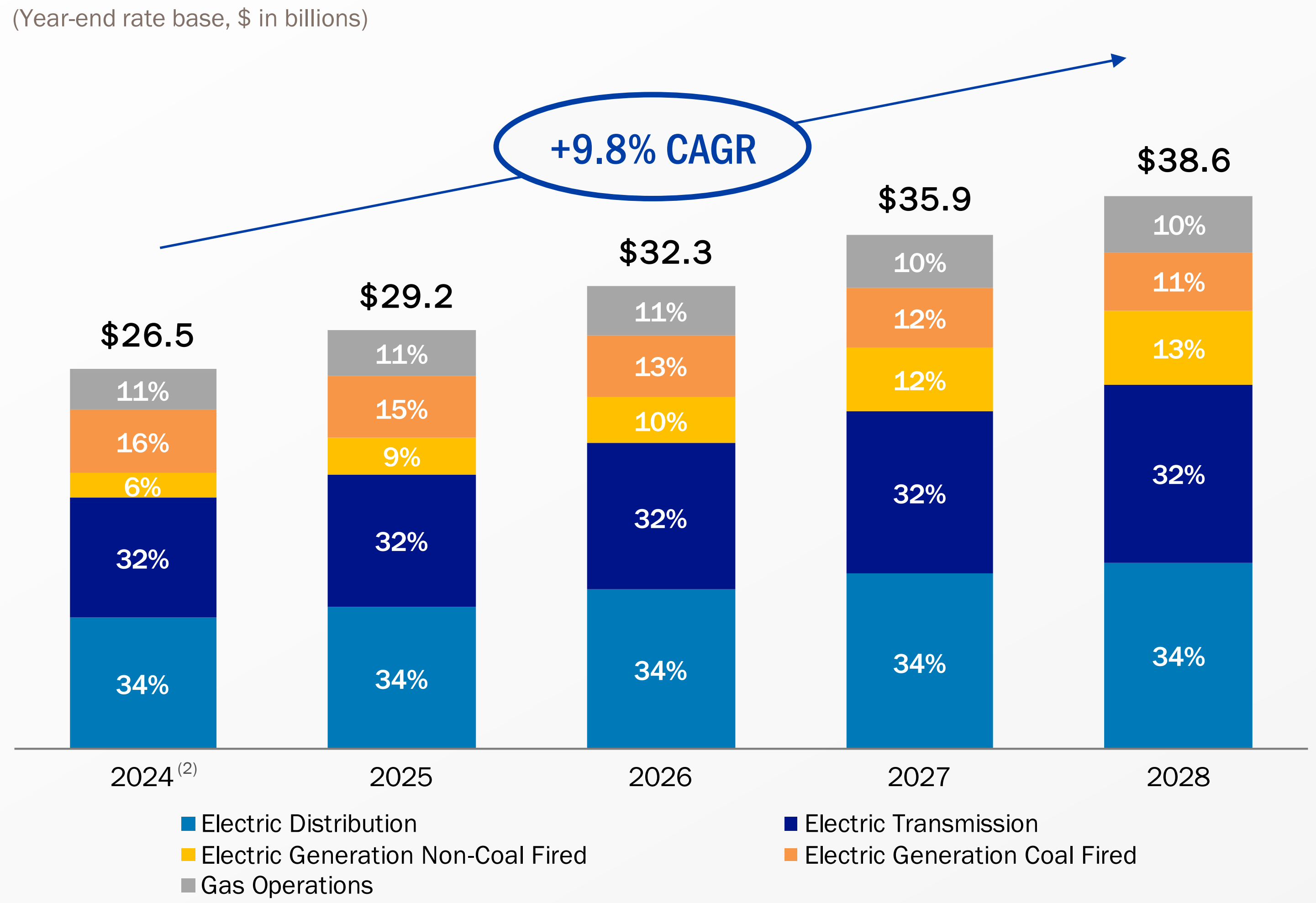
Notable Plan Updates:

- **Approximately $4 billion increase in 2025 – 2027 period vs. prior capital plan**
  - $1.3B increase in KY related to near-term generation needs and environmental compliance as well as $0.5B for system hardening and grid resiliency
  - $1.0B increase in PA primarily for storm hardening in distribution and $0.2B for data center growth in transmission
  - $0.6B of IT investments across the enterprise for customer service, finance, supply chain, HR, etc.
- **Update includes nearly $5 billion of projected investment needs in 2028**
  - Investments to replace aging infrastructure, increase T&D system reliability and resiliency, and execute new generation construction in Kentucky

Note: Totals may not sum due to rounding.

Rate Base CAGR Increased to 9.8% Through 2028

Projected annual rate base growth (2024 – 2028)[1]



- **Rate base growth increases to 9.8% over updated plan period vs. 6.3% in prior plan period**
- **Two-thirds of rate base relates to investments in electric transmission and distribution infrastructure**
- **Percentage of rate base related to coal generation declines to below 11% by 2028**

Note: Totals may not sum due to rounding.

(1) Rhode Island rate base excludes acquisition-related adjustments for non-earning assets.

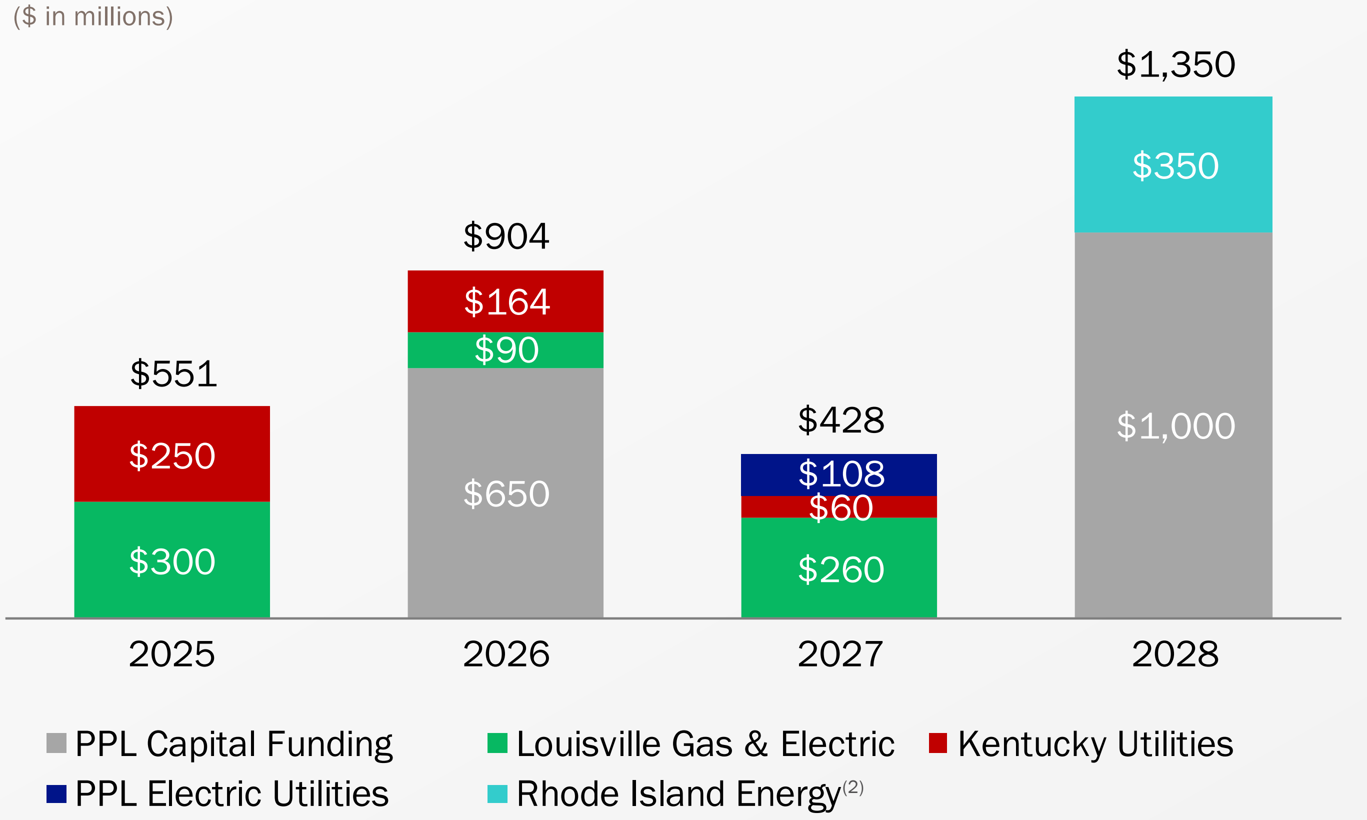
(2) Reflects projected 2024 year-end rate base for Pennsylvania electric distribution (annual PUC filing at end of March).

Credit and Financing Plan Update

Updated plan maintains our excellent credit position

- **Plan supports strong credit metric targets to maintain premier credit ratings**
  - 16% - 18% FFO/CFO to debt throughout plan
  - Holding company debt projected to remain less than 25% of total debt
- **Project equity needs of $2.5 billion through 2028 to support capital investment plan**
  - Base financing plan is to use an ATM program and complement with other equity-like financing structures
- **Manageable debt maturity stack**
  - $550 million of maturities in 2025
  - Limited floating rate debt exposure (~5% of total long-term debt)

Debt Maturity Outlook (1)

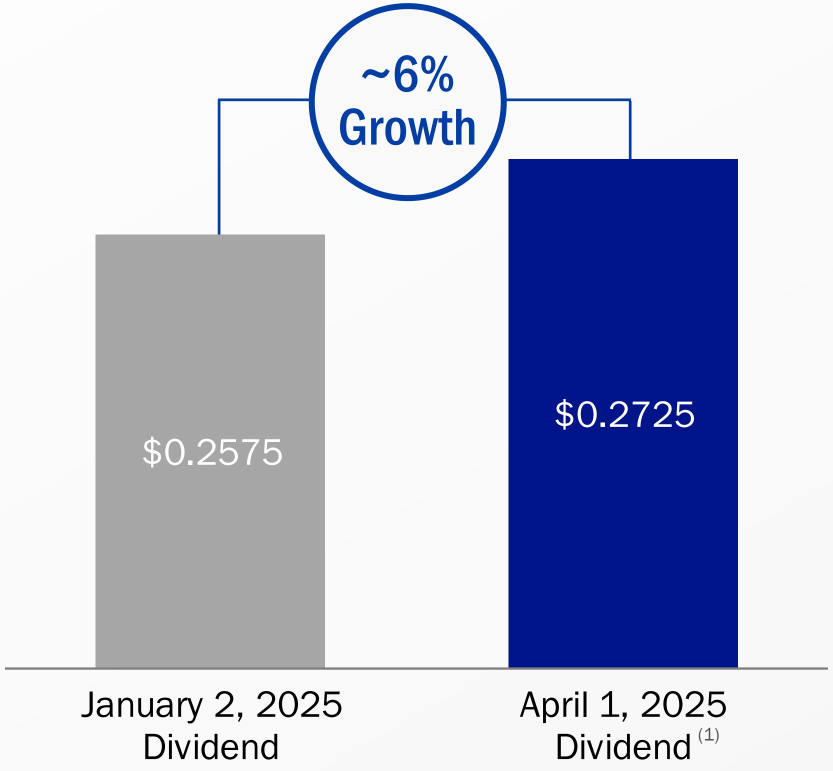


(1) As of December 31, 2024
(2) Excludes Rhode Island Energy's sinking fund payments that are due annually until the bond's final maturity (less than $1 million in 2025).

Increasing Quarterly Common Stock Dividend

Quarterly dividend increased to $0.2725 per share

(Dividends per share)



- **Announced ~6% increase to PPL's quarterly dividend to $0.2725 per share (from $0.2575)**
  - Annualized dividend now $1.09 per share[2]
- **Payable April 1, 2025 to shareowners of record as of March 10, 2025**
- **Continue to target dividend growth within 6% - 8%[2]**
  - Expect to grow dividend at lower end of target range through current planning period given significant capital investment funding needs
- **Continues to support total return proposition of 9% - 12%[3]**

(1) Based on February 13, 2025 dividend declaration by Board of Directors.
(2) Subject to Board of Directors approval.
(3) Total return reflects PPL's targeted EPS growth rate plus dividend yield based on targeted annualized dividend and PPL's closing share price as of February 11, 2025.

Closing Remarks

Vince Sorgi

President & Chief Executive Officer

4th QUARTER 2024
INVESTOR UPDATE

February 13, 2025

Appendix

Supplemental Information

4th QUARTER 2024
INVESTOR UPDATE

February 13, 2025

PPL Investment Highlights

A total return proposition of 9% - 12%[1]

Large-cap, regulated U.S. utility operating in constructive regulatory jurisdictions

- Principal electric/gas utilities serving Kentucky, Pennsylvania, and Rhode Island
- Future test years in each jurisdiction; 60% of capital investment plan subject to reduced regulatory lag

Visible and predictable 6% - 8% annual EPS and dividend growth[2]

- $20B capital investment plan, driving average annual rate base growth of 9.8% through 2028
- Risk mitigating without high-risk projects in CapEx plan and lower event risk in our geographic regions
- Targeted annual O&M savings of at least $175M by 2026 from the company's 2021 baseline

Premier balance sheet supports organic growth and provides financial flexibility

- Top-tier credit ratings among peers: Baa1 rating at Moody's and A- rating at S&P
- Targeting 16% - 18% FFO/CFO to Debt

Compelling opportunity to expand and modernize generation

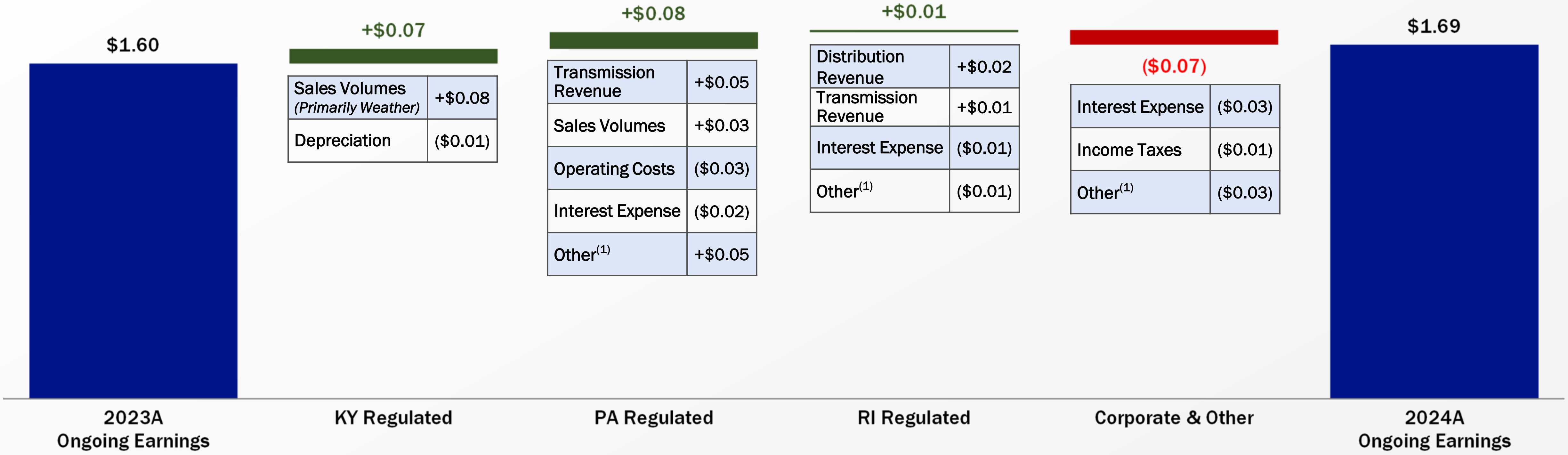
- Well positioned to support customer growth and economic development, including data centers
- Committed to net-zero carbon emission by 2050[3][4]

(1) Total return reflects PPL's targeted EPS growth rate plus dividend yield based on targeted annualized dividend and PPL's closing share price as of February 11, 2025.
(2) Refers to PPL's projected earnings per share growth from 2025 to 2028 and targeted dividend per share growth in line with EPS.
(3) PPL is economically transitioning coal-fired generation and has committed to not burn coal by 2050 unless it can be mitigated with carbon dioxide removal technologies.
(4) PPL is committed to a reasoned and deliberate glidepath to net-zero carbon emissions by 2050; ensuring safety, reliability and affordability remain intact during the transition.

Review of 2024 Financial Results

Ongoing earnings walk: 2024 vs. 2023

(Earnings per share)



Segment	KY Regulated	PA Regulated	RI Regulated	Corporate & Other	Total PPL
2024 Ongoing EPS	$0.84	$0.82	$0.21	($0.18)	$1.69

Note: See Appendix for the reconciliation of reported earnings to earnings from ongoing operations.

(1) Reflects factors that were not individually significant and certain intercompany activities that eliminate in consolidation.

Electricity Sales Volumes

Quarterly and trailing twelve-month retail sales comparison by segment (1)

(GWh)	Weather-Normalized Electricity Sales Volume						Actual Electricity Sales Volume		
Pennsylvania	Three Months Ended Dec. 31,			Trailing Twelve Months Ended Dec. 31,			Three Months Ended Dec. 31,		
	2024	2023	% Change	2024	2023	% Change	2024	2023	% Change
Residential	3,640	3,656	(0.4%)	14,521	14,418	0.7%	3,573	3,509	1.8%
Commercial	3,312	3,273	1.2%	13,825	13,663	1.2%	3,294	3,256	1.2%
Industrial	2,040	2,022	0.9%	8,500	8,380	1.4%	2,040	2,022	0.9%
Other	22	23	NM*	74	76	NM*	22	22	NM*
Total	9,014	8,974	0.4%	36,920	36,536	1.1%	8,929	8,810	1.3%
Kentucky	Three Months Ended Dec. 31,			Trailing Twelve Months Ended Dec. 31,			Three Months Ended Dec. 31,		
	2024	2023	% Change	2024	2023	% Change	2024	2023	% Change
Residential	2,446	2,439	0.3%	10,576	10,533	0.4%	2,315	2,304	0.5%
Commercial	1,854	1,785	3.9%	7,752	7,591	2.1%	1,821	1,754	3.8%
Industrial	2,028	2,065	(1.8%)	8,576	8,469	1.3%	2,028	2,065	(1.8%)
Other	641	624	NM*	2,679	2,651	NM*	632	615	NM*
Total	6,969	6,913	0.8%	29,583	29,244	1.2%	6,796	6,739	0.8%

Annual EPS Sensitivity
Per 1% Change In Total Load
+/- $0.005 - $0.01
Per 1% Change In Total Load
+/- $0.01 - $0.02

*NM: Not Meaningful
Note: Totals may not sum due to rounding.
(1) Excludes Rhode Island Energy's sales volumes as its revenue is decoupled.

Capital Expenditure Plan

($ in millions)

Company Segment	Type	2025	2026	2027	2028	4-Year Total
Pennsylvania	Electric Distribution	$650	$975	$900	$875	$3,400
	Electric Transmission	$850	$875	$825	$775	$3,325
	PA Subtotal	**$1,500**	**$1,850**	**$1,725**	**$1,650**	**$6,725**
Kentucky	Electric Distribution	$400	$475	$475	$475	$1,825
	Electric Transmission	$250	$425	$475	$475	$1,625
	Electric Generation Non-Coal Fired	$725	$875	$1,325	$1,025	$3,950
	Electric Generation Coal Fired	$250	$325	$375	$300	$1,250
	Gas Operations	$175	$100	$125	$125	$525
	Other	$250	$225	$125	$100	$700
	KY Subtotal	**$2,050**	**$2,425**	**$2,900**	**$2,500**	**$9,875**
Rhode Island	Electric Distribution	$350	$375	$325	$300	$1,350
	Electric Transmission	$200	$300	$275	$250	$1,025
	Gas Operations	$225	$250	$250	$225	$950
	RI Subtotal	**$775**	**$925**	**$850**	**$775**	**$3,325**
PPL Corporation	**Total Utility Capex**	**$4,325**	**$5,200**	**$5,475**	**$4,925**	**$19,925**

Projected Rate Base (Year-End)

(Year-end rate base, $ in billions)

Company Segment	Type	2024 (1)	2025	2026	2027	2028
Pennsylvania	Electric Distribution	$4.5	$4.9	$5.4	$6.1	$6.5
	Electric Transmission	$5.8	$6.2	$6.7	$7.2	$7.6
	PA Subtotal	**$10.3**	**$11.0**	**$12.1**	**$13.3**	**$14.2**
Kentucky	Electric Distribution	$3.4	$3.7	$4.0	$4.3	$4.6
	Electric Transmission	$1.7	$2.0	$2.3	$2.7	$3.1
	Electric Generation Non-Coal Fired	$1.7	$2.5	$3.3	$4.4	$5.2
	Electric Generation Coal Fired	$4.4	$4.3	$4.3	$4.2	$4.1
	Gas Operations	$1.3	$1.5	$1.5	$1.6	$1.7
	KY Subtotal	**$12.4**	**$14.0**	**$15.4**	**$17.3**	**$18.6**
Rhode Island (2)	Electric Distribution	$1.3	$1.4	$1.7	$1.8	$1.9
	Electric Transmission	$1.0	$1.1	$1.2	$1.4	$1.6
	Gas Operations	$1.6	$1.8	$2.0	$2.1	$2.3
	RI Subtotal	**$3.8**	**$4.2**	**$4.8**	**$5.3**	**$5.8**
PPL Corporation	**Total Rate Base**	**$26.5**	**$29.2**	**$32.3**	**$35.9**	**$38.6**

Note: Totals may not sum due to rounding.

(1) Reflects projected 2024 year-end rate base for Pennsylvania electric distribution (annual PUC filing at end of March).
(2) Rhode Island rate base excludes acquisition-related adjustments for non-earning assets.

Debt Maturities

($ in millions)

	2025	2026	2027	2028	2029	2030+	Total
PPL Capital Funding	$0	$650	$0	$1,000	$0	$2,146	$3,796
PPL Electric Utilities	$0	$0	$108	$0	$116	$5,075	$5,299
Louisville Gas & Electric[1]	$300	$90	$260	$0	$0	$1,839	$2,489
Kentucky Utilities[1]	$250	$164	$60	$0	$0	$2,615	$3,089
Rhode Island Energy[2]	$1	$0	$0	$350	$0	$1,650	$2,001
Total Debt Maturities[3]	**$551**	**$904**	**$428**	**$1,350**	**$116**	**$13,325**	**$16,674**

Note: As of December 31, 2024. Totals may not sum due to rounding.

(1) Amounts reflect the timing of any put option on municipal bonds that may be put by the holders before the bonds' final maturities.
(2) Amounts reflect sinking fund payments that are due annually until the bond's final maturity.
(3) Does not reflect unamortized debt issuance costs and unamortized premiums (discounts) totaling ($171 million).

Liquidity Profile

($ in millions)

Entity	Facility	Expiration Date	Capacity	Borrowed	LCs & CP Issued (1)(2)	Unused Capacity
PPL Capital Funding	Syndicated Credit Facility (3)	Dec-2028	$1,250	$0	$138	$1,112
	Bilateral Credit Facility	Feb-2025	$100	$0	$0	$100
	Bilateral Credit Facility (4)	Feb-2025	$100	$0	$15	$85
	Subtotal		$1,450	$0	$153	$1,297
PPL Electric Utilities	Syndicated Credit Facility (5)	Dec-2028	$650	$0	$1	$649
Louisville Gas & Electric	Syndicated Credit Facility (6)	Dec-2028	$500	$0	$25	$475
Kentucky Utilities	Syndicated Credit Facility (6)	Dec-2028	$400	$0	$140	$260
Total PPL Credit Facilities			**$3,000**	**$0**	**$318**	**$2,682**

Note: As of December 31, 2024. Totals may not sum due to rounding.

(1) Letters of Credit (LCs) and Commercial Paper (CP).
(2) Commercial paper issued reflects the undiscounted face value of the issuance.
(3) Includes a $250 million borrowing sublimit for RIE and $1 billion sublimit for PPL Capital Funding. At December 31, 2024, PPL Capital Funding had $138 million of commercial paper outstanding and RIE had no commercial paper outstanding. On January 2, 2025, the capacity of the PPL Capital Funding syndicated credit facility was increased to $1.5 billion, with the RIE sublimit remaining $250 million and the PPL Capital Funding sublimit increasing to $1.25 billion.
(4) Uncommitted credit facility.
(5) On January 2, 2025, the capacity of the PPL Electric credit facility increased to $750 million.
(6) On January 2, 2025, the capacity of the LG&E and KU credit facilities were each increased to $600 million.

PPL's Credit Ratings

PPL Corporation

Credit Rating	S&P	Moody's
Secured	NR	NR
Unsecured	NR	NR
Long-term Issuer	A-	Baa1
Outlook	Stable	Stable

PPL Capital Funding

Credit Rating	S&P	Moody's
Secured	NR	NR
Unsecured	BBB+	Baa1
Long-term Issuer	A-	NR
Outlook	Stable	Stable

Rhode Island Energy

Credit Rating	S&P	Moody's
Secured	A	NR
Unsecured	A-	A3
Long-term Issuer	A-	A3
Outlook	Stable	Stable

LG&E and KU

Credit Rating	S&P	Moody's
Secured	A	A1
Unsecured	NR	NR
Long-term Issuer	A-	A3
Outlook	Stable	Stable

PPL Electric Utilities

Credit Rating	S&P	Moody's
Secured	A+	A1
Unsecured	NR	NR
Long-term Issuer	A	A3
Outlook	Stable	Stable

Note: As of December 31, 2024.

Appendix

Regulatory Overview

4th QUARTER 2024
INVESTOR UPDATE

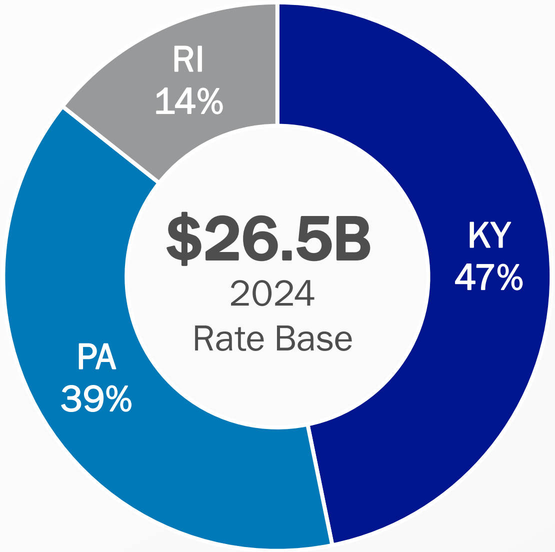
February 13, 2025

Constructive Regulatory Jurisdictions

Supportive of prudent investments in our electric and gas networks

Rate Base by Segment [1]

(Year-end rate base, $ in billions)



Key Regulatory Highlights

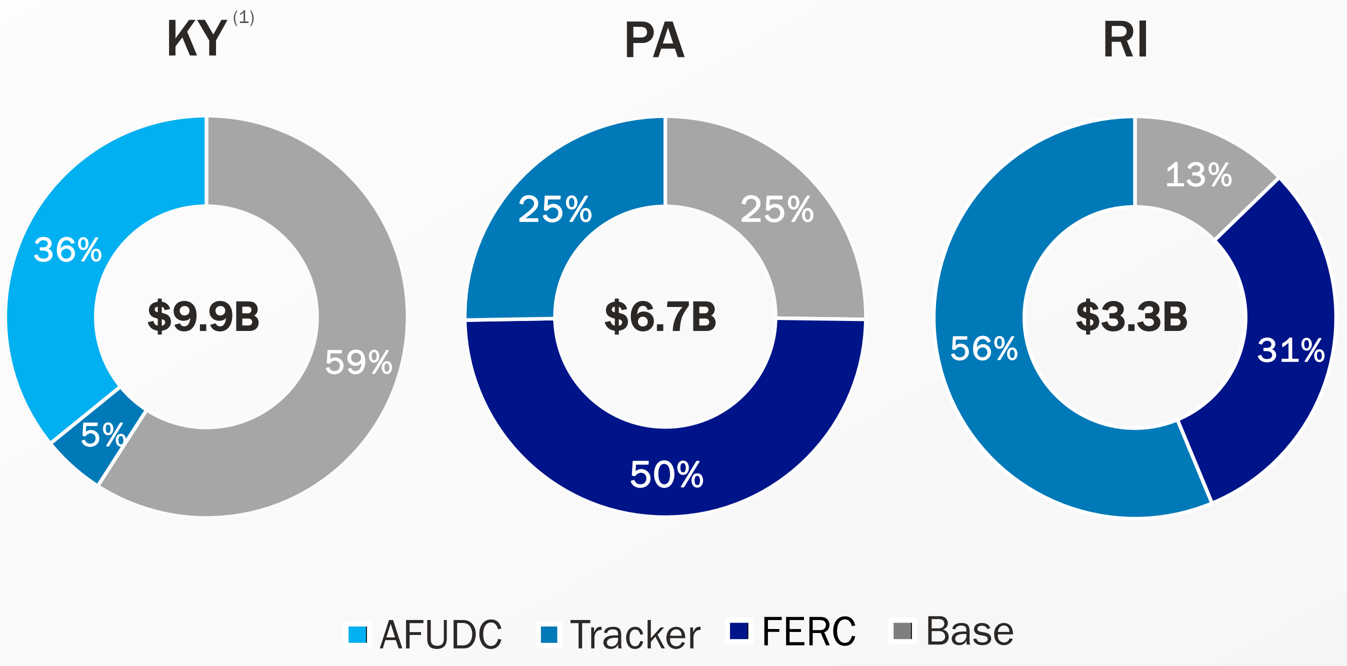
- **Contemporaneous recovery for ~60% of capital plan**
  - FERC formula rates for transmission in both PA and RI
  - ~80% of RI planned distribution capital investments relate to infrastructure, safety, and reliability (projected to be ISR eligible)
  - DSIC mechanism in PA provides hedge against lower sales volumes, storms and inflation outside of rate cases
  - ECR mechanism in KY provides recovery of additional environmental investments, if needed for regulatory compliance (ELGs, CCRs, etc.)
- **Future test years in all three jurisdictions for base rate cases** [2]
  - Multi-year rate plan applied in latest RI base rate case
  - History of rate case settlements in all three jurisdictions

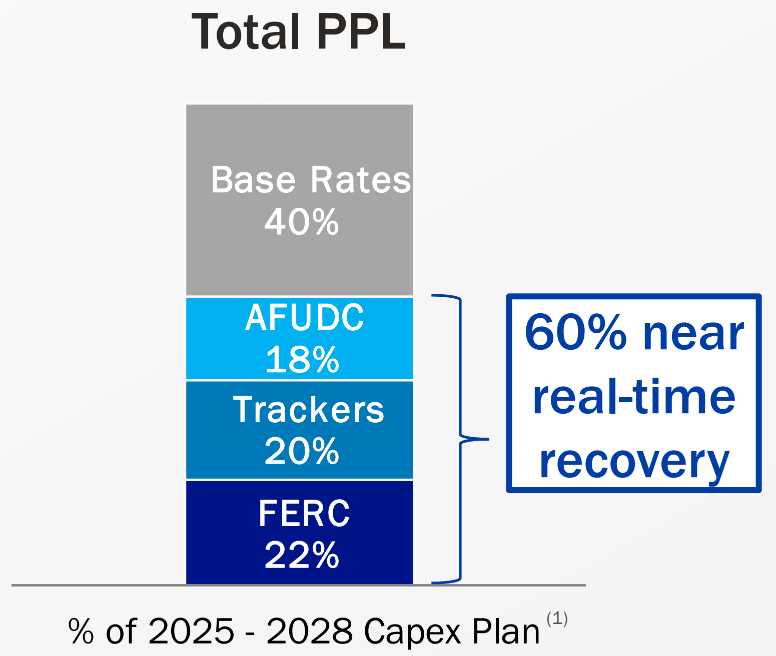
(1) Rhode Island rate base excludes acquisition-related adjustments for non-earning assets.
(2) In 2018, Rhode Island established a multi-year framework for Rhode Island Energy based on a historical test year but with the ability to forecast certain O&M categories for future years. All other O&M is increased by inflation each year. Includes annual rate reconciliation mechanism that incorporates allowance for anticipated capital investments.

Constructive Regulatory Mechanisms Reduce Lag

60% of PPL's capital investment plan is subject to reduced regulatory lag

2025 – 2028 Capital Plan by Projected Earnings Recovery Mechanism





Reduces the impact of regulatory lag on earnings for investments without base rate cases

(1) Reflects AFUDC treatment approval for authorized construction projects in Kentucky.

Pennsylvania Regulatory Overview

PPL Electric Utilities

Key Attributes

2024 Rate Base	
Year-End Rate Base ($B)	$10.3
% of Total PPL Rate Base	39%
Allowed ROE	
Electric Transmission	10.0% + adders(1)
Electric Distribution	(2)
DSIC	10.0%(3)
Capital Structure (2024)	
Equity	56%
Debt	44%
Last Base Rate Case (rates effective date)	1/1/2016
Test Year	Forward Test Year

Constructive Features Mitigating Regulatory Lag

- ✓ FERC Formula Transmission Rates
- ✓ Distribution System Improvement Charge (DSIC)
  - An alternative ratemaking mechanism providing more-timely cost recovery of qualifying distribution system capital expenditures
- ✓ Pass through of energy purchases
- ✓ Smart Meter Rider
- ✓ Storm Cost Recovery
- ✓ Alternative Ratemaking (4)
  - In Pennsylvania, there are various mechanisms available including: decoupling mechanisms, performance-based rates, formula rates, and multi-year rate plans

(1) Adders include 50-basis points for RTO membership and incremental returns for certain projects.
(2) Last Pennsylvania distribution base rate case was effective January 1, 2016 with an undisclosed ROE.
(3) The equity return rate used in the DSIC calculation is calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities. Effective April 1, 2025, the cost of equity is 10.0%.
(4) Alternative ratemaking is available for next distribution base rate case.

A Review of the DSIC Mechanism in Pennsylvania

Reduces regulatory lag associated with certain electric distribution investments

Purpose	➢ Distribution system improvement charge (DSIC) allows PPL Electric to recover reasonable and prudent costs incurred to repair, improve, or replace eligible property between base rate cases. ➢ The DSIC also provides PPL Electric with the resources to accelerate the replacement of aging infrastructure, comply with evolving regulatory requirements, and design and implement solutions to regional supply problems.
Eligible Property	➢ For PPL Electric, DSIC-eligible capital investments are approved by the PAPUC through 5-year, long-term infrastructure improvement plans (LTIIP). ➢ DSIC-eligible property consists of poles and towers, overhead conductors, underground conduit and conductors, and any fixture or device related to the aforementioned eligible property. It also includes costs related to highway relocation projects where an electric distribution company must relocate its facilities and other related capitalized costs.
Calculation	➢ The DSIC is calculated to recover the fixed costs (depreciation and pre-tax return) of eligible plant additions not previously reflected in PPL Electric's rates or rate base. ➢ The pre-tax return is calculated using the statutory state and federal income tax rates, PPL Electric's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. ➢ The cost of equity will be the equity return rate approved in PPL Electric's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission. Effective April 1, 2025, this cost of equity is 10.0%. ➢ The DSIC is updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC Update. For example, the DSIC rate effective April 1, 2025, reflects plan additions from December through February 2025.
Consumer Safeguards	➢ For PPL Electric, the amount of distribution revenues that are recoverable through the DSIC mechanism is capped at 5.0%. ➢ The DSIC is reset at zero if the company's return, as reported in the quarterly earnings report, shows that the utility will earn a rate of return that would exceed the allowable rate of return. ➢ The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC.

Kentucky Regulatory Overview

Louisville Gas & Electric and Kentucky Utilities

Key Attributes

2024 Rate Base	
Year-End Rate Base ($B)	$12.4
% of Total PPL Rate Base	47%
Allowed ROE	
Base	9.425%
ECR & GLT Mechanisms	9.35%
Capital Structure (2024)	
Equity	53%
Debt	47%
Last Base Rate Case (rates effective date)	7/1/2021
Test Year	Forward Test Year

Constructive Features Mitigating Regulatory Lag

- ✓ Environmental Cost Recovery (ECR) Surcharge
  - Provides near real-time recovery for approved environmental projects related to coal-fired generation
- ✓ Gas Line Tracker (GLT)
  - Approved mechanism for LG&E's recovery of certain costs associated with gas transmission lines, gas service lines, and leak mitigation
- ✓ Demand-Side Management (DSM) Cost Recovery
  - Provides recovery of energy efficiency programs
- ✓ Retired Asset Recovery (RAR) Rider (1)
  - Provides recovery of and on remaining net book value of unit, obsolete inventory, and uncollected costs of removal over a 10-year period from retirement date
- ✓ Fuel Adjustment Clause (FAC)
  - Pass through of costs of fuel and energy purchases
- ✓ Gas Supply Clause (GSC)
  - Pass through of costs of natural gas supply

(1) Retired Asset Recovery rider applies to the generating plants of LG&E and KU. In October 2024, LG&E made an initial filing under this rider (Docket: 2024-00317).

Rhode Island Regulatory Overview

Rhode Island Energy

Key Attributes

2024 Rate Base	
Year-End Rate Base ($B)	$3.8
% of Total PPL Rate Base	14%
Allowed ROE	
Electric Transmission	10.57% + adders(1)
Electric Distribution	9.275%(2)
Gas Distribution	9.275%(2)
Capital Structure (2024)	
Equity	51%
Debt	49%
Last Base Rate Case (rates effective date)	9/1/2018
Test Year	Multi-year(3)

Constructive Features Mitigating Regulatory Lag

- ✓ FERC Formula Transmission Rates
- ✓ Multi-year rate plans for electric and gas distribution
- ✓ Infrastructure, Safety, and Reliability (ISR) tracker
  - Annual recovery mechanism for certain capital and O&M costs for electric and gas distribution projects filed with the RIPUC
- ✓ Performance-based incentive revenues
  - Includes electric system performance, energy efficiency, natural gas optimization, and renewables incentives
- ✓ Revenue decoupling
- ✓ Storm cost recovery
- ✓ Pension expense tracker
- ✓ Energy Efficiency tracker

(1) Reflects base allowed ROE. Rhode Island Energy receives a 50-basis point RTO adder and additional project adder mechanisms that may increase the allowed ROE up to 11.74%.
(2) Reflects base allowed ROE. Rhode Island Energy can earn higher returns than the base allowed ROE through incentive mechanisms and efficiencies that are supported by customer sharing mechanisms. Earnings sharing with customers of 50% when earned ROE is between 9.275% and 10.275% and increases to 75% sharing for customers when earned ROE exceeds 10.275%.
(3) Based on regulatory framework established in 2018, which included a multi-year framework for Rhode Island Energy electric and gas base rates based on a historical test year with the ability to forecast certain O&M categories for future years. All other O&M expenses are increased by inflation each year. Includes annual rate reconciliation mechanism that incorporates allowance for anticipated capital investments.

Appendix

Reconciliations and Disclaimers

4th QUARTER 2024
INVESTOR UPDATE

February 13, 2025

Reconciliation of Segment Reported Earnings to Earnings from Ongoing Operations: Current Year

After-Tax (Unaudited) ($ in millions)	Three Months Ended December 31, 2024 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	Twelve Months Ended December 31, 2024 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings (1)	$ 127	$ 133	$ 19	$ (102)	$ 177	$ 620	$ 574	$ 109	$ (415)	$ 888
Less: Special Items (expense) benefit:										
Talen litigation costs, net of tax of $1 (2)	-	-	-	-	-	-	-	-	(2)	(2)
Strategic corporate initiatives, net of tax of $0, $1, $0, $2, $2 (3)	-	(1)	-	(2)	(3)	(1)	(5)	-	(5)	(11)
Acquisition integration, net of tax of $0, $11, $13, $66 (4)	-	-	2	(44)	(42)	-	-	(46)	(250)	(296)
PPL Electric billing issue, net of tax of $5 (5)	-	-	-	-	-	-	(13)	-	-	(13)
FERC transmission credit refund, net of tax of $0 (6)	-	-	-	-	-	1	-	-	-	1
ECR beneficial reuse transition adjustment, net of tax of $2 (7)	-	-	-	-	-	(4)	-	-	-	(4)
DER projects impairment, net of tax of $6, $6 (8)	-	(15)	-	-	(15)	-	(15)	-	-	(15)
IT transformation, net of tax of $5, $5 (9)	-	-	-	(19)	(19)	-	-	-	(22)	(22)
Total Special Items	-	(16)	2	(65)	(79)	(4)	(33)	(46)	(279)	(362)
Earnings from Ongoing Operations	$ 127	$ 149	$ 17	$ (37)	$ 256	$ 624	$ 607	$ 155	$ (136)	$ 1,250

After-Tax (Unaudited) (per share – diluted)	Three Months Ended December 31, 2024 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	Twelve Months Ended December 31, 2024 KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings (1)	$ 0.17	$ 0.18	$ 0.02	$ (0.13)	$ 0.24	$ 0.83	$ 0.78	$ 0.15	$ (0.56)	$ 1.20
Less: Special Items (expense) benefit:										
Strategic corporate initiatives (3)	-	-	-	-	-	-	-	-	(0.01)	(0.01)
Acquisition integration (4)	-	-	-	(0.05)	(0.05)	-	-	(0.06)	(0.34)	(0.40)
PPL Electric billing issue (5)	-	-	-	-	-	-	(0.02)	-	-	(0.02)
ECR beneficial reuse transition adjustment (7)	-	-	-	-	-	(0.01)	-	-	-	(0.01)
DER projects impairment (8)	-	(0.02)	-	-	(0.02)	-	(0.02)	-	-	(0.02)
IT transformation (9)	-	-	-	(0.03)	(0.03)	-	-	-	(0.03)	(0.03)
Total Special Items	-	(0.02)	-	(0.08)	(0.10)	(0.01)	(0.04)	(0.06)	(0.38)	(0.49)
Earnings from Ongoing Operations	$ 0.17	$ 0.20	$ 0.02	$ (0.05)	$ 0.34	$ 0.84	$ 0.82	$ 0.21	$ (0.18)	$ 1.69

(1) Reported Earnings represents Net Income.
(2) PPL incurred legal expenses related to litigation associated with its former affiliate.
(3) Represents costs primarily related to PPL's centralization and other strategic efforts.
(4) Primarily integration and related costs associated with the acquisition of Rhode Island Energy.
(5) Certain expenses related to billing issues.
(6) Prior period impact related to a FERC refund order.
(7) Prior period impact for an Environmental Cost Recovery mechanism revenue adjustment related to a Kentucky Public Service Commission order.
(8) Impairment of distributed energy resources project costs associated with a pilot solar program for which PPL will not seek regulatory recovery.
(9) Costs associated with PPL's restructuring and rebuilding of its IT infrastructure, organization and systems.

Reconciliation of Segment Reported Earnings to Earnings from Ongoing Operations: Prior Year

After-Tax (Unaudited) ($ in millions)	Three Months Ended December 31, 2023					Twelve Months Ended December 31, 2023				
	KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings [1]	$ 120	$ 135	$ 26	$ (168)	$ 113	$ 552	$ 519	$ 96	$ (427)	$ 740
Less: Special Items (expense) benefit:										
Talen litigation costs, net of tax of $24, $26 [2]	-	-	-	(93)	(93)	-	-	-	(99)	(99)
Strategic corporate initiatives, net of tax of $0, $1, $0, $1, $3 [3]	-	(1)	-	(3)	(4)	(1)	(2)	-	(10)	(13)
Acquisition integration, net of tax of $2, $16, $14, $58 [4]	-	-	(10)	(59)	(69)	-	-	(56)	(218)	(274)
PA tax rate change	-	(1)	-	-	(1)	-	-	-	-	-
Sale of Safari Holdings, net of tax of ($1), $0 [5]	-	-	-	(1)	(1)	-	-	-	(4)	(4)
PPL Electric billing issue, net of tax of $4, $10 [6]	-	(9)	-	-	(9)	-	(24)	-	-	(24)
FERC transmission credit refund, net of tax of $0, $2 [7]	(1)	-	-	-	(1)	(6)	-	-	-	(6)
Unbilled revenue estimate adjustment, net of tax of $2, $2 [8]	(5)	-	-	-	(5)	(5)	-	-	-	(5)
Other non-recurring charges, net of tax of $1, $1, $0 [9]	-	(3)	-	-	(3)	-	(3)	-	(15)	(18)
Total Special Items	(6)	(14)	(10)	(156)	(186)	(12)	(29)	(56)	(346)	(443)
Earnings from Ongoing Operations	$ 126	$ 149	$ 36	$ (12)	$ 299	$ 564	$ 548	$ 152	$ (81)	$ 1,183

After-Tax (Unaudited) (per share – diluted)	Three Months Ended December 31, 2023					Twelve Months Ended December 31, 2023				
	KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total	KY Reg.	PA Reg.	RI Reg.	Corp. & Other	Total
Reported Earnings [1]	$ 0.16	$ 0.18	$ 0.04	$ (0.23)	$ 0.15	$ 0.75	$ 0.70	$ 0.13	$ (0.58)	$ 1.00
Less: Special Items (expense) benefit:										
Talen litigation costs [2]	-	-	-	(0.13)	(0.13)	-	-	-	(0.13)	(0.13)
Strategic corporate initiatives [3]	-	-	-	-	-	-	-	-	(0.01)	(0.01)
Acquisition integration [4]	-	-	(0.01)	(0.08)	(0.09)	-	-	(0.07)	(0.30)	(0.37)
Sale of Safari Holdings [5]	-	-	-	-	-	-	-	-	(0.01)	(0.01)
PPL Electric billing issue [6]	-	(0.02)	-	-	(0.02)	-	(0.04)	-	-	(0.04)
FERC transmission credit refund [7]	-	-	-	-	-	(0.01)	-	-	-	(0.01)
Unbilled revenue estimate adjustment [8]	(0.01)	-	-	-	(0.01)	(0.01)	-	-	-	(0.01)
Other non-recurring charges [9]	-	-	-	-	-	-	-	-	(0.02)	(0.02)
Total Special Items	(0.01)	(0.02)	(0.01)	(0.21)	(0.25)	(0.02)	(0.04)	(0.07)	(0.47)	(0.60)
Earnings from Ongoing Operations	$ 0.17	$ 0.20	$ 0.05	$ (0.02)	$ 0.40	$ 0.77	$ 0.74	$ 0.20	$ (0.11)	$ 1.60

(1) Reported Earnings represents Net Income.
(2) Represents a settlement agreement with Talen Montana, LLC and affiliated entities and other litigation costs.
(3) Represents costs primarily related to PPL's centralization and other strategic efforts.
(4) Primarily integration and related costs associated with the acquisition of Rhode Island Energy.
(5) Primarily final closing and other related adjustments for the sale of Safari Holdings, LLC.
(6) Certain expenses related to billing issues.
(7) Prior period impact related to a FERC refund order.
(8) Prior period impact of a methodology change in determining unbilled revenues.
(9) PA Reg. includes certain expenses associated with a litigation settlement. Corp. & Other primarily includes certain expenses associated with a litigation settlement. Corp. & Other primarily includes certain expenses related to distributed energy investments.

Forward-Looking Information Statement

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Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power

Eliza Martin
Ari Peskoe

March 2025

ENVIRONMENTAL & ENERGY LAW PROGRAM
HARVARD LAW SCHOOL

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Executive Summary

Some of the largest companies in the world — including Amazon, Google, Meta, and Microsoft — are looking to secure electricity for their energy-intensive operations.[1] Their quests for power to supply their growing "data centers" are super-charging a growing national market for electricity service that pits regional utilities against each other. In this paper, we investigate one aspect of this competition: how utilities can fund discounts to Big Tech by socializing their costs through electricity prices charged to the public. Hiding subsidies for trillion-dollar companies in power prices increases utility profits by raising costs for American consumers.

Because for-profit utilities enjoy state-granted monopolies over electricity delivery, states must protect the public by closely regulating the prices utilities charge for service. Regulated utility rates reimburse utilities for their costs of providing service and provide an opportunity to profit on their investments in new infrastructure. This age-old formula was designed to motivate utility expansion so it would meet society's growing energy demands.

The sudden surge in electricity use by data centers — warehouses filled with power-hungry computer chips — is shifting utilities' attention away from societal needs and to the wishes of a few energy-intensive consumers. Utilities' narrow focus on expanding to serve a handful of Big Tech companies, and to a lesser extent cryptocurrency speculators, breaks the mold of traditional utility rates that are premised on spreading the costs of beneficial system expansion to all ratepayers. The very same rate structures that have socialized the costs of reliable power delivery are now forcing the public to pay for infrastructure designed to supply a handful of exceedingly wealthy corporations.

To provide data centers with power, utilities must offer rates that attract Big Tech customers and are approved by the state's public utility commission (PUC). Utilities tell PUCs what they want to hear: that the deals for Big Tech isolate data center energy costs from other ratepayers' bills and won't increase consumers' power prices. But verifying this claim is all but impossible. Attributing utility costs to a specific consumer is an imprecise exercise premised on debatable claims about utility accounting records. The subjectivity and complexity of ratemaking conceal utility attempts to funnel revenue to their competitive lines of business by overcharging captive ratepayers. While PUCs are supposed to prevent utilities

from extracting such undue profits from ratepayers, utilities' control over rate-setting processes provides them with opportunities to obscure their self-interested strategies.

Detecting wealth transfers from ratepayers to utility shareholders and Big Tech companies is particularly challenging because utilities ask PUCs for confidential treatment of their contracts with data centers, which limits scrutiny of utilities' proposed deals and narrows the scope of regulators' options when they consider utilities' prices and terms. Meanwhile, regulators face political pressure to approve major economic investments already touted by elected officials for their economic impacts. Rejecting new data center contracts could lead potential Big Tech customers to construct their facilities in other states. Indeed, Big Tech companies have repeatedly told utility regulators that unfavorable utility rates could lead them to invest elsewhere.[2]

In the following sections, we investigate how utilities are shifting the costs of data centers' electricity consumption to other ratepayers. Based on our review of nearly 50 regulatory proceedings about data centers' rates, and the long history of utilities exploiting their monopolies, we are skeptical of utility claims that data center energy costs are isolated from other consumers' bills. After describing the rate mechanisms that shift utility costs among ratepayers, we explain how both existing and new rate structures, as well as secret contracts, could be transferring Big Tech's energy costs to the public. Next, we provide recommendations to limit hidden subsidies in utility rates. Finally, we question whether utility regulators should be making policy decisions about whether to subsidize data centers and speculate on the long-term implications of utility systems dominated by trillion-dollar software and social media companies.

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I. Government-Set Rates Incentivize Utilities to Pursue Data Center Growth at the Expense of the Public

Data centers are large facilities packed with computer servers, networking hardware, and cooling equipment that support services like cloud computing and other data processing applications. While data centers have existed for decades, companies are now building much larger facilities. In 2023, companies began developing facilities that will consume hundreds of megawatts of power, as much as the city of Cleveland.[3] As several companies race to develop artificial intelligence (AI), the scale and energy-intensity of data center development is rapidly accelerating. By the end of 2024, companies started building gigawatt-scale data center campuses and are envisioning even larger facilities that will demand more energy than the nation's largest nuclear power plant could provide.[4]

The sudden and anticipated near-term growth of cloud computing infrastructure to accommodate the development of AI is driving a surge of utility proposals to profit from Big Tech's escalating demands. By 2030, data centers may consume as much as 12 percent of all U.S. electricity and could be largely responsible for *quintupling* the annual growth in electricity demand.[5] This growth is likely to be concentrated in regions with robust access to telecommunications infrastructure and where utilities pledge to quickly meet growing demand. Data centers could substantially expand utilities' size, both financial and physical, as they develop billions of dollars of new infrastructure for Big Tech.[6]

Data center growth is overwhelming long-standing approaches to approving utility rates. Nearly every consumer pays for electricity based on the utilities' average costs of providing service to similar ratepayers. A handful of special interests, particularly large industrial users, pay individualized rates that are negotiated with the utility and often require PUC approval. Data center growth could flip the current ratio of consumers paying general rates to special-interest customers paying unique contracts pursuant to special contracts. In this section, we summarize the potential for massive data center growth and then explore how this growth is challenging long-standing ratemaking practices and is causing the public to subsidize Big Tech's power bills.

A. Utilities Are Projecting Massive Data Center Energy Use

Industry experts and utilities are forecasting massive data center growth, and their projections keep going up. In January 2024, one industry consultancy projected 16 GW of new data center demand by 2030.[7] But by the end of the year, experts were anticipating data center growth to be as high as 65 GW by 2030.[8] Individual utilities are even more bullish. For example, Georgia Power anticipates its total energy sales will nearly double by the early 2030s, a trend it largely attributes to data centers.[9] In Texas, Oncor announced 82 gigawatts of potential data center load,[10] equivalent to the maximum demand of Texas' energy market in 2024.[11] Similarly, AEP, whose multi-state system peaks at 35 GW, expects at least 15 GW of new load from data center customers by 2030,[12] although AEP's Ohio utility added that "customers have expressed interest" in 30 GW of additional data centers in its footprint.[13]

There are reasons, however, to be skeptical of utilities' projections. Utilities have an incentive to provide optimistic projections about potential growth; these announcements are designed in part to grab investors' attention with the promise of new capital spending that will drive future profits.[14] When pressed on their projections, utilities are often reticent to disclose facility-specific details on grounds that a data center's forecasted load is proprietary information.[15] This secrecy can lead utilities and analysts to double-count a data center that requests service from multiple utilities.[16] To acquire power as quickly as possible, data center companies may be negotiating with several utilities to discover which utility can offer service first.

Technological uncertainty further complicates the forecasting challenge. Future innovation may increase or decrease data centers' electricity demand. The current surge in data center growth is traceable to the release of ChatGPT in 2022 and the subsequent burst of AI products and their associated computing needs.[17] Computational or hardware advancements might reduce AI's energy demand and diminish data center demand.[18] For instance, initial reports in January 2025 about the low energy consumption of DeepSeek, a ChatGPT competitor, fueled speculation that more efficient AI models might be just as useful while consuming far less energy. Even if more energy efficient AI models materialize, however, their lower cost could lead consumers to demand more AI services, which could drive power use even higher.[19]

Nonetheless, investment is pouring into data center growth. At a January 21, 2025 White House press conference, OpenAI headlined an announcement of $100 billion in data center investment with the possibility of an additional $400 billion over four years.[20] Earlier that month, Microsoft revealed that it would spend $80 billion on data centers in 2025, including more than $40 billion in the U.S.[21] Two weeks earlier, Amazon said it would spend $10 billion on expanding a data center in Ohio.[22] And two weeks before that, Meta announced its own $10 billion investment to build a new data center in Louisiana.[23]

While the scale and pace of data center growth is impossible to forecast precisely, we know that utilities are projecting and pursuing growth. In the next section, we explore the ratemaking and other regulatory processes that socialize utilities' costs and risks. Unlike companies that face ordinary business risks to their profitability, utilities rely on government regulators to approve their prices and can manipulate rate-setting processes to offer special deals to favored customers that shift the costs of those discounts to the public. This "hidden value transfer," a term coined by Aneil Kovvali and Joshua Macey, is a strategy employed by monopolist utilities to increase profits at the expense of their captive ratepayers.[24] Regulators are supposed to protect against hidden value transfers by aligning rates with the costs utilities incur to serve particular types of consumers. But this rate design strategy is rife with imprecision. In reality, ratepayers are paying for each other's electricity consumption, and data center growth could potentially exacerbate the cross-subsidies that are rampant in utility rates.

B. Utility Rates Socialize Power System Costs Using the "Cost Causation" Standard

The U.S. legal system bestows significant economic advantages on investor-owned utilities (IOUs), which are for-profit companies that enjoy state-granted monopolies to deliver electricity. Government-approved electricity prices reimburse utilities for their operational expenses and provide utilities an opportunity to earn a fixed rate of return on their capital investments. With a monopoly service territory and regulated prices designed to facilitate earnings growth, a utility is insulated from many ordinary business risks and shielded from competitive pressures.

Public utility regulators, or PUCs, must protect the public from a utility's monopoly power and, in the absence of competition, motivate the company to provide reliable and cost-effective service. To meet those goals, PUCs determine whether utility service is offered to all consumers within a utility's service territory at rates and conditions that are "just and reasonable."[25] This standard, enshrined in state law, requires PUCs to balance captive consumers' interests in low prices and fair terms of service against the utility's interest in maximizing returns to its shareholders. A utility rate case is the PUC's primary mechanism for weighing these competing interests by setting equitable prices for consumers that provide for the utilities' financial viability.

"Cost causation" is a guiding principle in ratemaking that dictates consumer prices should align with the costs the utility incurs to provide service to that customer or group of similar ratepayers. By approving rates that roughly meet the cost causation standard, PUCs prevent "undue discrimination" between utility ratepayers, a legal requirement that is typically specified in state law.

While the PUC makes the final decision to approve consumer prices, the utility drives the ratemaking process. In a rate case, the utility's primary goal is to collect enough money to cover its operating expenses and earn a profit on its capital investments. A utility proposes new rates by filing its accounting records and other data and analysis that form the basis of its preferred prices. Once it establishes its "revenue requirement," the utility then proposes to divide this amount among groups of consumers based on their usage patterns, infrastructure requirements, and other characteristics that the utility claims inform its costs of providing service to those consumers. Typical groups, also known as ratepayer classes, include residential, commercial, and industrial consumers. Finally, the utility proposes standardized contracts known as tariffs for each ratepayer class that include uniform charges and terms of service for each member of that ratepayer class.

Under this ratemaking process, residential ratepayers often pay the highest rates because they are distributed across wide areas, often in single-family homes that consume little energy.[26] The utility recovers the costs of building, operating, and maintaining its extensive distribution system to serve residential ratepayers by spreading those costs over the relatively small amount of energy consumed by households. By contrast, an industrial consumer uses far more energy than a household and is likely connected to the power system through higher voltage lines and needs less local infrastructure than residential ratepayers. The utility can distribute lower total infrastructure costs over far greater energy sales to generate a lower industrial rate. Properly designed rates should "produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer."[27]

But ratemaking is not "an exact science," and there is not a single correct result.[28] In a utility rate case, various parties advocate for their own self-interest by contesting the utility's filing. Consumer groups and other parties urge the PUC to reduce the utility's revenue requirement, which could potentially lower all rates. But once the revenue requirement is set, consumer groups are pitted against each other as they try to reduce their share of the total amount. Their arguments are based on competing approaches to cost causation, with each party claiming that lower rates for itself align with economic principles, fairness, and other subjective values. Well-resourced participants, such as industrial groups that have a significant incentive to argue for lower power costs, hire lawyers and analysts to comb through the utility's filings and argue that their rates should be lower.

But parties face an uphill battle challenging the utility's accounting records, engineering studies, and other evidence the utility files to justify its preferred rates. Because it initiates the rate case and generates the information needed for the PUC to approve a rate, the utility is inherently advantaged. The information asymmetry between utilities and other parties, as well as the imprecision and subjectivity of the cost causation standard, can facilitate subsidization across classes of ratepayers. We highlight three reasons that PUCs may purposefully or unwittingly approve rates that depart from the cost causation standard.

First, attributing the utilities' costs to various ratepayer classes depends on contested assumptions and disputed methodologies. Different approaches to cost allocation will yield different results. As a pioneer in public utility economics once explained, there are "notorious disagreements among the experts as to the choice of the most rational method of [ ] cost allocation — a disagreement which seems to defy resolution because of the absence of any objective standard of rationality."[29] Parties, including the utility, provide the PUC with competing analyses that are designed to meet their own objectives. For instance, industrial consumers will sponsor a study that concludes lower rates for the industrial rate class is consistent with the cost causation principle. Other parties favor their own interests in what can be a zero-sum game over how to divide the utility's revenue requirement.

Second, the PUC may have its own preferences. In most states, utility commissioners are appointed by the governor, but in ten states they are elected officials. Either commissioner may face political pressure to favor a particular ratepayer class. For instance, an elected commissioner may be inclined to provide lower rates to residential ratepayers who will vote on the commissioner's reelection. An appointed commissioner may choose to align utility rates with a governor's economic development agenda by providing lower rates to major employers, such as the commercial or industrial class. Other pressures may bias regulators in favor of other interests. As it weighs competing evidence about cost allocation provided by various parties in a rate case, the PUC has discretion to find a particular study more credible and may choose a rate structure that aligns with the sponsoring party's goals and the PUC's own preferences. While other parties may challenge a PUC's decision in court, courts are unlikely to overturn a PUC's judgment about cost allocation.[30]

Third, the utility may exploit its informational advantages and intentionally provide false information. A rate case is premised on detailed accounting records filed by the utility about the expenses it incurs to provide service. The spreadsheets and other information that the utility files are based on internal records not available to the PUC or rate-case parties. Even if the utility provides some of its records in response to a party's request, the information might be too voluminous for the PUC or other parties to verify. Ultimately, the PUC relies on the utility's good faith. However, recent cases show that utilities are filing fabricated or misleading records.[31]

A random audit of multi-state utility company FirstEnergy by the Federal Energy Regulatory Commission (FERC) found that the utility had hidden lobbying expenses tied to political corruption by mislabeling them as legitimate expenses in its accounting books. According to the audit, the utility's internal controls had been "possibly obfuscated or circumvented to conceal or mislead as to the actual amounts, nature and purpose of the lobbying expenditures."[32] The audit concluded that the utility's mislabeling allowed the inappropriate lobbying expenses to be included in rates.[33] Rate cases did not detect this deception. Only an audit, informed by an extensive federal sting operation, revealed the utility's deceit. Regulators have recently uncovered other utilities filing false or misleading information in regulated proceedings.[34]

Once the regulators approve utility rates, some consumers can shift costs to other ratepayers by fine-tuning their energy consumption. As we discuss in more detail in part II.B.3, rates for commercial and industrial ratepayers typically include demand charges that are tied to each consumer's energy consumption during the utility's or regional power system's moment of peak demand that year. By anticipating when that peak will happen and reducing consumption of utility-delivered power at that moment, a data center or other energy-intensive consumer can substantially reduce its bill. While this "peak shaving" can reduce power prices for other consumers, it also forces other ratepayers to pay part of the energy-intensive consumer's share of infrastructure costs.

Despite its flaws, ratemaking continues to be the dominant approach to financing power sector infrastructure. Uniform, stable prices provide predictable revenue that motivates investors to fund utility expansion. Rate regulation typically insulates investors from many ordinary business risks by putting ratepayers on the hook for the company's engineering, construction, or procurement mistakes. For instance, regulators often allow utilities to increase rates when their projects are over-budget. The utility rarely faces financial consequences for missteps that would cause businesses that rely on competitive markets to lose profits.

Some energy-intensive consumers can be exempted from this ratemaking process that socializes costs and shifts risks to the public. The special rates for these consumers are set in one-off agreements that can lock in long-term prices and shield it from risks faced by other ratepayers. These contracts, which typically require PUC approval, allow an individual consumer to take service under conditions and terms not otherwise available to anyone else. Special rates are, in essence, "a discriminatory action, but one that regulators can justify under certain conditions."[35]

To protect ratepayers, some state laws authorizing special contracts require PUCs to evaluate whether the contract meets the cost causation standard.[36] However, the "notorious disagreements" about how to measure whether a consumer is paying for its costs of service still plague the special-contract cost causation analysis. And, as we describe below, proceedings about special contracts present unique obstacles to evaluating cost causation.

In other states, however, laws authorizing special contracts do not prevent PUCs from approving below-cost contracts. For instance, Kansas law allows regulators to approve special rates if it determines that the rate is in the state's best interest based on multiple factors, including economic development, local employment, and tax revenues.[37] A recent law enacted in Mississippi strips utility regulators of any authority to review contracts between a utility and a data center.[38]

Regardless of the standard for reviewing special contracts, there is significant political pressure on regulators to approve these deals, even if such development results in higher electricity costs for other ratepayers. Regulators do not want to be seen as the veto point for an economic development opportunity, which may have already been publicized by the company and the governor. Because utilities may be competing for the profitable opportunity to serve a particular energy-intensive consumer, they have an incentive to offer low prices, even if that reduced rate results in higher costs for the utility's other ratepayers. As noted, despite their wealth, Big Tech companies seek low energy prices and make siting decisions based in part on price.[39] Regulatory scrutiny of special contracts is therefore a critical backstop for protecting ratepayers.

II. How Data Center Costs Creep into Ratepayers' Bills

When a utility expands its system in anticipation of growing consumer demand, it typically seeks to include the capital costs of new infrastructure in its rates. If approved, ratepayers share the costs of the utility's expansion pursuant to a cost allocation formula accepted by the PUC. This approach, while imperfect for the reasons described in the previous section, has facilitated population growth and economic development by forcing ratepayers to subsidize new infrastructure that will allow new residents and businesses to receive utility-delivered energy.

For many utilities, their expectations about growth are now dominated by new data centers. Rather than being dispersed across a utility's service territory like homes and businesses, these new data center consumers that are benefitting from utility expansion are identifiable and capable of paying for infrastructure that will directly serve their facilities. If PUCs allow utilities to follow the conventional approach of socializing system expansion, utilities will impose data centers' energy costs on the public. The easiest way for utilities to shift data centers' energy costs to the public is to simply follow long-standing practices in rate cases.

In our view, however, utilities are often using more subtle ratemaking methods to push data centers' energy costs onto consumers' bills.

In this section, we focus on three mechanisms that can force consumers to pay for data center's energy costs. First, special contracts between utilities and data centers, approved through opaque regulatory processes, are transferring data center costs to other consumers. Second, disconnected processes for setting federally regulated transmission and wholesale power rates and state-set consumer prices are: A) causing consumers to pay for interstate infrastructure needed to accommodate new data centers; B) putting consumers on the hook for new infrastructure built for data-center load that never materializes; and C) allowing data centers to strategically reduce energy usage during a few hours to reduce their bills and shift costs to other consumers. Third, data centers that bypass traditional utility ratemaking by contracting directly with power generators may also be raising electricity prices for the public. These co-location agreements between a data center and adjacent non-utility generator may trigger an increase in power market prices and distort regulated electricity delivery rates.

A. Shifting Costs through Secret Contracts

Special contracts are offered by utilities to energy-intensive consumers to attract their business. While regulators in many states are required to protect the public from such cutthroat practices that harm ratepayers, we explain in this section why we are skeptical about utility claims that special contracts for data centers do not force the public to pay for Big Tech's energy costs.

Our review of 40 state PUC proceedings about special contracts with data centers finds that regulators frequently approve special contracts in short and conclusory orders. While PUC rate case decisions are lengthy documents that engage with the evidence filed by the utilities and other parties, most PUC orders approving special contracts provide only cursory analysis of the utility's proposal. One challenge for PUCs is that few, if any, parties participate in these proceedings. As a result, the PUC has little or no evidence in the record to compete with the utility's claim that the contract isolates data center energy costs from other ratepayers' bills.

The PUC often deters parties from arguing against the utility's proposed special contract by reflexively granting utility requests to shield its proposal from public view.[40] The PUC's own grant of confidentiality adds a procedural barrier to greater participation and prevents the public from even attempting to calculate the potential costs of these deals.[41] But perhaps the greater impediment to third-party analysis of proposed special contracts is that ratepayers believe that they have little at stake in the proceedings. Unlike rate cases, which set the prices consumers pay, a special contract will only have indirect financial effects on other ratepayers if it shifts costs that the energy-intensive customer ought to pay on to other ratepayers' bills. Because meaningfully participating in a special contract case has a high cost and a generally low reward, otherwise interested parties have typically not bothered to contest them. But the scale of data center special contracts demands attention because the costs being shifted to the public could be staggering.

A special contract shifts costs to other ratepayers when the customer pays the utility a price lower than the utility's costs to serve that customer. To cover the shortfall, utilities will attempt to raise rates for other ratepayers in a subsequent rate case.[42] The amount of the shortfall, and whether there is any shortfall at all, depends on how the utility calculates its costs of providing service to the data center. As discussed above, there are "notorious disagreements" about appropriate methodologies, and even the term "cost" can itself be subject to dispute. Experts debate, for instance, when to use average or marginal costs and whether short- or long-term costs are suitable metrics. When utilities use one metric in a rate case and another metric in a special contract proceeding, they could be causing spillover effects that harm ratepayers.[43]

The disagreements about methodologies and complexities of the calculations underscore a foundational challenge to reviewing a special contract rate. As discussed above, PUC rate case decisions do not purport to assign utility costs to individual consumers but instead apportion cost responsibility among similar ratepayers grouped together as classes. But in a special contract proceeding, the utility makes the unusual claim that it can isolate its costs to serve a single consumer. Without contrary evidence filed by interested parties, the PUC may have little basis for rejecting the utility's analysis.

Even without the benefit of third-party analyses in special contract proceedings, PUC orders may summarize cross-subsidy concerns raised by their own staff. But challenging the utility's analysis is costly and time-intensive, and staff may not have the resources to provide robust analysis. Similarly, state ratepayer advocates occasionally participate in these proceedings and raise cross subsidy arguments, but they are also often stretched too thin to provide a detailed response to the utility's proposal. As a result, we find that many PUC orders approving special contracts simply conclude that the proposed contract is reasonable without meaningfully engaging with the proposal.[44]

Such PUC orders are therefore not persuasive in assuaging concerns that the public may be subsidizing Big Tech's energy costs. Moreover, as discussed, state regulators may face political pressure not to veto a significant construction project in the state. The utility's assertion that it is protecting other ratepayers may provide enough cover for regulators to approve a special contract. The obscurity and complexity of these proceedings provides utilities with opportunities to hide data center energy costs and force them onto other consumers' bills.

Recent litigation against Duke Energy, one of the largest utilities in the country, exposed that the company was acting on its incentive to shift costs of a special contract to its other ratepayers. Duke's scheme responded to a new power plant developer offering competitive contracts to supply small non-profit utilities that had been purchasing power from Duke.[45] Duke's internal documents disclosed through litigation revealed that the new company was far more efficient than Duke and the utility therefore could not compete for customers based on price. Nonetheless, Duke offered one of its larger customers a new contract that amounted to a $325 million discount compared to its existing deal with Duke.[46] Additional internal utility documents revealed that Duke developed a plan to "shift the cost of the discount" to its other ratepayers by raising their rates.[47] Duke's strategy to force its ratepayers to subsidize the special-contract customer's energy was discovered only because the power plant developer sued Duke in federal court under antitrust law.

While our paper focuses on how consumers are likely subsidizing Big Tech's energy costs through their utility rates, we acknowledge that the reverse is also theoretically possible. A data center taking service under special contracts could be *overpaying*. A utility proposing a special contract might prefer to overcharge one deep-pocketed customer through a special contract in order to reduce rates for the public. While this pricing strategy may seem politically attractive for the utility and PUC, it seems unlikely to attract new data centers.

Regardless of a utility's motivation, regulators are supposed to be skeptical of a sudden surge in utility spending. Superficial reviews of special contracts are insufficient when they are collectively committing utilities to billions of dollars for Big Tech customers. The recent Duke litigation illustrates how utilities take advantage of their monopolies to force ratepayers into subsidizing their competitive lines of businesses. Discounted rates can give a utility an edge in the data center market,[48] and hiding the costs of discounts in ratepayers' bills boosts utility profits. To prevent utilities from overcharging captive ratepayers for the benefit of their competitive businesses, both PUCs and FERC have developed regulatory mechanisms that attempt to prevent such subsidies.[49] For instance, FERC applies special scrutiny to contracts between utilities and power plants that are owned by the same corporate parent. FERC's concern is that because state regulators must let the utility recover its FERC-regulated costs in consumer's rates, "such sales could be made at a rate that is too high, which would give an undue profit to the affiliated [power plant] at the expense of the franchised public utility's captive customers."[50]

Special contracts with data centers are the latest iteration of a long-standing problem with monopolist utilities. Policing cost-shifts in this context is particularly challenging due to the opaque nature of the proceedings, the complexity and subjectivity of assessing the utility's costs of serving an a single consumer, and political pressure on PUCs to approve contracts.

B. Shifting Costs through the Gap Between Federal and State Regulation

When a PUC approves a utility's revenue requirement, it must allow the utility to include interstate transmission and wholesale power market costs that are regulated by FERC.[51] In much of the country, utilities procure power through markets administered by non-profit corporations called Regional Transmission Organizations (RTOs). Market prices are influenced by a host of factors, such as fuel and technology costs, and ultimately reflect generation supply and consumer demand. If supply is constrained by a data center demand surge, market prices would likely increase, at least in the short term. Consumers' utility bills will include these higher power market prices.

PUCs can protect ratepayers from market price increases by allocating the costs of higher prices to data centers. But PUCs rarely order utilities to adjust the formulae that spread FERC-regulated market and transmission costs to ratepayers. In this section, we illustrate how ratepayers can pay more for power due to data center demand by focusing on FERC-regulated transmission costs. Federal law provides FERC with exclusive authority to set utilities' transmission revenue requirements and allocate a utility's transmission revenue requirement to multiple utilities. Under FERC's rules, costs of a new transmission line can be paid entirely by a single utility or shared among utilities if there is agreement that the new line benefits multiple utilities. When costs are shared, a region-specific formula approved by FERC divides costs roughly in proportion to the power system benefits each utility receives, such as lower market prices and improved reliability.[52]

Under either the single-utility or multi-utility approach, PUCs apply their own formula for dividing FERC-allocated transmission costs among ratepayer classes. These separate cost allocation schemes can allow data center energy costs to creep into other consumers' bills when new data centers trigger a need for transmission upgrades. We illustrate by discussing examples of each type of transmission cost recovery and then explain how rate designs embedded in special contracts or tariffs can allow data centers to reduce their bills at the expense of ratepayers.

1. *Separate Federal and PUC Transmission Cost Allocation Methods Allow Data Center Infrastructure Costs to Infiltrate Ratepayers' Bills*

In December 2023, the PJM RTO, a utility alliance stretching from New Jersey to Chicago and south to North Carolina, approved $5 billion of transmission projects whose costs would be shared based among PJM's utility members.[53] PJM identified two factors driving the need for this transmission expansion: retirement of existing generation resources and "unprecedented data center load growth," primarily in Virginia.[54] Pursuant to its FERC-approved cost allocation method, PJM split half of the transmission costs across its footprint based on each utilities' share of regional power demand and allocated the remaining half using a computer simulation of the regional transmission network that estimates benefits each utility receives from the new transmission projects.[55] Under this approach, PJM assigned approximately half of the total cost to Virginia utilities, approximately 10% to Maryland utilities, and the remainder to utilities across the region.[56]

Each state's PUC then allocates the costs assigned by PJM to ratepayer classes of each utility it regulates. In Maryland, across the state's three IOUs assign, an average of 66 percent of transmission costs are assigned to residential ratepayers.[57] The larger of Virginia's two IOUs includes more than half of its transmission costs in residential rates.[58] Thus, in both states, residential ratepayers are paying the majority of regional transmission costs that are tied to data center growth. From the public's perspective, this result appears to violate the cost causation principle. After all, residential ratepayers are not causing PJM to plan new transmission.

PJM's approach, however, recognizes that new regional transmission benefits all ratepayers by improving reliability, allowing for more efficient delivery of power, and providing other power system improvements that are broadly shared. PJM developed its cost-sharing approach with the understanding that new transmission would be designed primarily to provide public benefits. New transmission designed for a few energy-intensive consumers, and not broad public benefits, is inconsistent with PJM's premise. That said, by increasing transmission capacity, new regional transmission lines for data centers may provide ancillary benefits to all ratepayers. PJM's power system simulation, which it uses to allocate half the costs of transmission expansion, demonstrates the shared benefits of this new infrastructure. Proponents of transmission expansion argue that such power flow models validate the current approach of allocating transmission costs to benefiting ratepayers because the models can calculate with reasonable accuracy who benefits from new transmission and therefore who should pay for it.

But even assuming that ancillary benefits for all ratepayers are adequate to justify current methods for regional transmission cost allocation, PJM only spreads costs among the region's utilities. Each utility then has its own methods, approved by PUCs, for allocating transmission investment to its ratepayers. The PUC-approved methods typically presume that ratepayers share in the benefits of new transmission in proportion to their total energy consumption. This approach causes residential ratepayers in Maryland, which consume more than half of the state's electricity, to pay for the lion's share of Maryland utilities' costs of new PJM-planned transmission. Without reforms, consumers will be paying billions of dollars for regional infrastructure that is designed to address the needs of just a few of the world's wealthiest corporations.[59]

Obsolete PUC cost allocation formulas can also cause ratepayers to pay for transmission costs that are not regionally shared. For instance, in July 2024, Virginia's largest utility applied to the PUC for permission to build infrastructure that would serve a new large data center. PUC staff reviewing the proposal found that but for the data center's request, the project "likely, if not certainly, would not be needed at this time."[60] In its application, the utility told state regulators that the $23 million project would be paid for through its FERC-approved transmission tariff.[61] Under the utility's existing state-approved tariff, about half of all costs assigned through the FERC-regulated tariff are billed to residential ratepayers, and the remaining half are billed to other existing ratepayers.[62] The bottom line is that existing tariffs force the public to foot the bill for the data center's transmission.

2. *Utilities May Be Saddling Ratepayers with Stranded Costs for Unneeded Transmission*

If a utility's data center growth projections fail to materialize, ratepayers could be left paying for transmission that the utility constructed in anticipation of data center development. Claiming that it was addressing this "stranded cost" issue, American Electric Power (AEP) of Ohio proposed a new state-regulated tariff that that would require data center customers to enter into long-term contracts with the utility before receiving service. AEP's proposed contract would require the data center to pay 90 percent of costs associated with its maximum demand for a ten-year period, including FERC-regulated transmission costs.[63] According to the utility, this upfront guarantee protects AEP's other ratepayers from the risk that the utility builds new infrastructure for a data center that never materializes and prevents the utility from offloading all of these "stranded" costs on other ratepayers.

While these long-term contracts would at least partially insulate AEP's ratepayers from data center transmission costs, neighboring utilities pointed out that they could still be left paying for stranded costs through PJM's allocation of transmission investments. Their protests explain that if AEP builds new transmission lines in anticipation of data center load growth, and those lines are paid for via PJM's regional cost allocation, then those costs would be split among all PJM-member utilities. As noted, PJM allocates half the costs of new transmission lines to its utility members based on their share of regional energy sales. If AEP's data center customers commence operations, AEP's own share of regional transmission costs would increase in proportion to its rising share of regional energy sales. In that scenario, other utilities in the region may not overpay for transmission needed for AEP's data center customers.

Protesting utilities in the Ohio PUC proceeding focus on the possibility that AEP's data center customers cancel their projects or consume less energy than anticipated after AEP has spent money developing new transmission to meet projected data center demand.[64] Under that scenario, total regional transmission costs would rise due to AEP's spending, but AEP's share of total costs would not increase proportionally. As a result, other regional utilities would face increasing costs to pay for infrastructure developed to meet AEP's unrealized data center energy demand. How much individual consumers pay for the new infrastructure would depend on how each utility allocates transmission costs to various ratepayer classes pursuant to a PUC rate case decision.

New transmission projects paid for by a single utility can also raise stranded cost concerns. In December 2024, FERC approved a contract that governed the construction of transmission facilities needed to provide service to a new data center.[65] Under the contract, the data center will immediately pay for new infrastructure needed to connect the facility to the existing transmission network but will not directly pay for necessary upgrades to existing transmission facilities. Instead, the utility AES pledged to include those upgrade costs in the transmission rates paid by all ratepayers through a subsequent regulatory process. A separate state-regulated tariff for energy-intensive consumers would require the data center, and not other consumers, to ultimately pay for the upgrades. In addition, the contract requires the data center to pay for the upgrades in the event it does not commence operations or uses less energy than would be required under the state-regulated tariff to pay for the upgrades over the time. Our understanding is that this approach to transmission cost recovery for new energy-intensive consumers is fairly common and not limited to data centers, but ratepayer advocates are concerned that data centers' commitments may be more uncertain than other types of energy-intensive consumers.

The Ohio ratepayer advocate therefore protested the contract, arguing that the language protecting other consumers from paying for the transmission upgrades was "unacceptably ambiguous."[66] The Ohio advocate urged FERC to require "specific language to preclude shifting data center costs" to other consumers.[67] FERC nonetheless approved the contract because it found that these concerns were premature and noted that they may be raised in future proceedings that directly address any proposed cost shifts.[68] In a short concurrence, FERC Commissioner Mark Christie questioned whether the rate treatment proposed by the utility that could burden consumers with stranded costs is justified.

3. *By Slightly Reducing Their Energy Use, Data Centers Can Increase Ratepayers' Transmission and Wholesale Market Charges*

Like other ratepayers, data centers pay an energy price for each unit of energy they consume as well as a monthly flat fee. Data centers, and many non-residential ratepayers, also face utility-imposed demand charges that are tied to their peak consumption during a specified month, year, or other time period. These charges are intended to reflect the costs of building power systems that have sufficient capacity to generate and deliver energy when consumer demand is unusually high. In RTO regions, PUC-regulated data center special contracts and tariffs likely reflect FERC-approved demand charges that incorporate regional transmission costs and may also include costs of procuring sufficient power plant capacity to meet peak demand. By reducing their energy use during just a few hours of the year, data centers may be able to reduce their share of regional costs that are allocated to demand charges and effectively force other ratepayers to pick up the tab.

Electricity use is constantly changing, and it peaks when consumers ramp up cooling and heating systems during exceptionally hot or cold days. Meeting these moments of peak demand is very expensive. Consumers pay for transmission and power plant infrastructure that is mostly unused but nonetheless necessary for providing power during a few peak hours each year. While utilities have employed several methods for assessing demand charges, many energy-intensive consumers are billed based on their own consumption at the moment the regional system reaches its peak demand.[69]

Data centers and other large energy users have significant incentives to forecast when this peak hour will occur and reduce their consumption of utility-delivered power during that hour. To avoid shutting down or reducing their production during hours when the system might hit its peak, energy-intensive consumers may install backup generators that displace utility-provided power. Large power users may already have their own power generators to protect against outages or improve the quality of utility-delivered power.[70] Needless to say, most consumers that face demand charges, such as small businesses, do not have a sufficient incentive to forecast the system peaks or install on-site generation. As data centers' share of regional energy consumption grows, Big Tech will be able to shift an increasingly large share of the region's costs to other ratepayers, particularly if their demand charges are easily manipulable.

PUCs can often prevent these cost shifts among consumers who take service from rate-regulated utilities in their states. Federal law requires only that the total costs allocated through FERC-approved tariffs must be passed on to utilities and then ultimately to consumers through PUC-regulated tariffs or special contracts. PUCs can choose their own methods for allocating those costs among ratepayers. Because data centers' special contracts are confidential, we often do not know whether utilities and PUCs are facilitating cost shifts through demand charges. Whether data centers are taking service under tariffs or special contracts, PUCs should ensure that rate structures are not allowing data centers to shift costs through manipulable demand charges.

That said, as we discuss below in part III.E, cutting peak consumption can reduce costs for everyone if utilities build their systems for a lower peak that accounts for a data center's ability to turn off or self-power. The problem is that utilities are expanding based on an assumption that data centers will operate at full power with utility-delivered power during peak periods. When a data center uses its own generation during peak periods to avoid demand charges, it is shifting the costs of an overbuilt system to the public.

C. Shifting Costs by "Co-Locating" Data Centers and Existing Power Plants

Power plant owners have developed their own scheme for attracting data centers that could shift energy costs from data centers to ratepayers. Under "co-location" arrangements, a data center connects directly to an existing power plant behind the plant's point of interconnection to the utility-owned transmission network. By delivering and taking power without using the transmission network, power plant owners and data centers argue that they ought to be exempt from paying utility-assessed energy delivery fees. Utilities have contested this arrangement because it denies them profitable opportunities to build new infrastructure to connect data centers to their networks.

In their haste to secure power as quickly as possible, data centers are looking to contract with existing generation, particularly nuclear power plants. By connecting directly to a power plant, data centers aim to avoid a potentially lengthy process administered by a utility to connect the data center to the utility's power delivery system. Locating load behind a power plant's point of delivery to the transmission network is not new. But the potential scale of data center growth and possibility that some significant share of that growth will co-locate has spawned disputes between power plant owners and utilities.

We highlight the key points about co-location by focusing on regulatory proceedings that involve Constellation, the largest owner of nuclear plants in the U.S., and Exelon, the largest utility in the U.S. that owns only delivery infrastructure and not power plants. Until 2022, Constellation and Exelon were housed under the same corporate parent. The company's restructuring into separate generation and delivery companies allows each of those businesses to independently pursue policies that best meet their financial interests. Data center growth began to rapidly escalate shortly thereafter and has revealed tensions between utilities and companies that compete in wholesale electricity markets for profits.

Co-location is a vague term. Because financial consequences will follow from any regulatory definition of co-location, utilities and power generators dispute how co-location technically functions. Constellation claims that because a data center co-located with one of its nuclear plants cannot receive power from the grid, it is therefore "fully isolated" from the transmission network.[71] Exelon counters that "as a matter of physics and engineering," the co-located data center is "fully integrated with the electric grid."[72] Utilities and other parties point out that a nuclear plant must operate in sync with the other plants connected to the transmission network and claim that the data center benefits from this arrangement even if the transmission system is not delivering power to it.[73]

This technical distinction could affect whether co-located entities are utility ratepayers that pay for delivery service. Constellation argues that because the utility is not delivering energy to the data center, the data center is not a utility customer, and it should not have to pay any FERC- or PUC-regulated delivery charges. Exelon opposes that result and has estimated that a single proposed co-location arrangement between a nuclear owner and a data center would shift between $58 million and $140 million of transmission and state-regulated distribution charges to other ratepayers.[74]

But Constellation and other generators dispute that calculation, claiming that this "phantom . . . 'cost shift' is, at best, merely a back-of-the-envelope estimate" of the revenue a utility would collect if the data center signed up as its customer.[75] Co-location, according to the nuclear plant owners, does not actually cause other ratepayers to pay higher transmission rates but instead precludes them from receiving lower delivery rates that they might pay when a new energy-intensive customer becomes a utility ratepayer and pays its proportional share of the utility's cost of service (a hypothetical that likely does not occur when the new customer receives a one-off price pursuant to a special contract).

But analysts are concerned that co-location can actually raise prices in interstate power markets. Across much of the country, generators are constantly competing through auction markets to supply power. In a few regions, market operators conduct separate annual, monthly, or seasonal auctions for capacity to procure sufficient resources for meeting peak consumer demand. Each power plant can offer capacity into the auction equivalent to its maximum potential for energy generation. In the PJM region, nuclear plants accounted for 21 percent of total capacity that cleared the most recent auction.[76]

PJM's independent market monitor, who fiercely promotes and defends PJM's markets, recently warned that colocation could "undermine" PJM's markets. He posited that if all nuclear plants in the region attracted co-located customers, "the impact on the PJM grid and markets would be extreme. Power flows on the grid that was built in significant part to deliver low-cost nuclear energy to load would change significantly. Energy prices would increase significantly as low-cost nuclear energy is displaced by higher cost energy . . . Capacity prices would increase as the supply of capacity to the market is reduced."[77] Should this scenario play out, the region's ratepayers could be forced to pay higher prices due to data centers' purchasing decisions. However, as noted, steep increases in demand due to data center growth could increase wholesale market prices regardless of whether data centers co-locate with existing power plants.

For utilities, opposing co-location is not purely about protecting their ratepayers or upholding the integrity of interstate markets. Co-location threatens their control over power delivery by allowing data centers to take energy directly from a large power producer. In some states, utilities might claim that state laws prohibit co-location because they provide the utility with a monopoly on retail sales.[78] Co-location would also reduce the profits that utilities would otherwise stand to gain from constructing new infrastructure to serve data centers.

In an ongoing FERC proceeding, Constellation claims that utilities' opposition to co-location is an anti-competitive ploy to capitalize on their state-granted monopolies.[79] The company alleges that co-location arrangements at two of its nuclear plants are "being held hostage by one or two monopoly utilities . . . [that] have taken the law into their own hands, and are unilaterally blocking co-location projects unless the future data center customers accede to utility demands to take [ ] transmission services . . . from the utility and sign up for retail distribution services."[80] Utilities may be trying to delay Constellation's projects until FERC provides clear guidance on co-location arrangements, including whether data centers and nuclear plants will pay any transmission charges.[81]

Even if FERC sets new rules the two sides are likely to continue squabbling about the details. With billions of dollars on the line, each side might have an incentive to litigate, which would add risk to co-location schemes.

III. Recommendations for State Regulators and Legislators: Strategies for Protecting Consumers from Big Tech's Power Costs

Without systematic changes to prevailing utility ratemaking practices, the public faces significant risks that utilities will take advantage of opportunities to profit from new data centers by making major investments and then shifting costs to their captive ratepayers. The industry's current approaches of luring data centers with discounted contracts or lopsided tariffs are unsustainable.

We outline five recommendations for PUCs to better protect consumers from subsidizing Big Tech's data centers: A) establishing guidelines for reviewing special contracts, B) shifting new data centers from special contracts to tariffs, C) facilitating competition and the development of "energy parks" that are not connected to any utility-owned network, D) requiring utilities to provide more frequent demand forecasts;, and E) allowing new data centers to take service only if they commit to flexible operations.

A. Establish Robust Guidelines for Reviewing Special Contracts

PUCs rarely reject proposed special contracts with data centers. As we discussed, many states' laws provide PUCs with broad discretion to approve special contracts, do not specify a particular standard of review, and even allow the PUC to approve a contract that shifts costs to other ratepayers. Given the unprecedented scale and pace of data center special contracts, PUCs should establish more rigorous guidelines for reviewing special contracts that are aimed at protecting consumers.

In Kentucky, the Public Service Commission must make several findings on the record before approving a special contract.[82] Under the PSC's self-imposed guidelines, special contracts that include discounts are allowed only when the utility has excess generation capacity. The guidelines limit discounts to five years and no more than half the duration of the contract. The PSC must also find that the contract rate exceeds the utility's marginal costs to serve that customer and that the contract requires the customer to pay any of the utility's fixed costs associated with providing service to that customer.

Applying its guidelines, the PSC recently rejected a utility's proposed special contract with a cryptocurrency speculator because it found the contract did not shield consumers from the crypto venture's power costs.[83] The PSC was critical of the utility's projections about regional market and transmission prices and therefore did not find credible the utility's claim that the contract would cover the utility's cost to provide energy to the crypto speculator. Industrial ratepayers, several environmental and local NGOs, and Kentucky's attorney general, acting on behalf of consumers, participated in the proceeding and criticized the proposed contract.

While the PSC's guidelines compel it to address vital consumer protection issues, the rule cannot force regulators to critically analyze the utilities' filing or prevent the PSC from merely rubber-stamping a utility's proposed special contract. Vigorous oversight cannot be mandated by law: it requires dedicated public servants. The effectiveness of any consumer protection guidelines depends on the people who implement it, including PUC staff that review utility proposals and the commissioners who make the ultimate decisions. Nonetheless, we believe that establishing guidelines that require regulators to make specific findings about a proposed special contract would improve upon the status quo.

B. Require New Data Centers to Take Service Under Tariffs

Special contracts are vehicles for shifting special interests' energy costs to consumers. Approved in confidential proceedings by PUCs facing political pressure to approve deals and often with no competing interests participating, special contracts allow utilities to take advantage of the subjectivity and complexity of their accounting practices to socialize energy-intensive customers' costs to the public. The existing guardrails that ostensibly allow regulators to police special contracts are not working to protect consumers.

Guided by their consumer-protection mandate, regulators should stop approving any special contracts and instead require utilities to serve data centers through tariffs that offer standard terms and conditions for all future data-center customers. Unlike a one-off special contract that provides each data center with unique terms and conditions, a tariff ensures that all data centers pay under the same terms and that the impact of new customers is addressed by considering the full picture of the utility's costs and revenue. This holistic and uniform approach ends the race-to-the-bottom competition that incentivizes utilities to attract customers by offering hidden discounts paid for by other ratepayers.

That said, standard tariffs are not a talisman for protecting consumers. As we have emphasized, cost allocation is an imprecise exercise that depends on myriad assumptions and projections. However, tariff proceedings and rate cases are more procedurally appropriate forums than a special contract case to consider and address cost-allocation issues. Unlike special contracts, tariffs are reviewed in open dockets that allow the public and interested parties to scrutinize proposals and understand long-term implications of proposed rates should they go into effect. Once approved, a data-center tariff can be revisited in subsequent rate cases where the utility proposes to increase rates and allocate its costs among ratepayers, including data centers. All ratepayers will have an incentive to participate in those cases and offer evidence that challenge data centers' interests.

Several utilities have already been moving away from special contracts to tariffs. Recent and ongoing proceedings are highlighting issues that demand careful scrutiny, including whether to create new data-center-only tariffs and how to protect existing ratepayers from costs of new infrastructure needed to meet data centers' demands. We briefly canvas these issues.

A threshold issue is whether an existing utility tariff for energy-intensive ratepayers is appropriate for data centers or whether a new tariff is necessary to address issues that are unique to data centers. Ratepayer classes are generally defined by the similar costs that the utility incurs to serve members of that class. Data centers may, of course, oppose new tariffs that impose more expensive prices than they would pay if they took service under existing tariffs for energy-intensive ratepayers.

In Ohio, for instance, AEP proposed to create classes for new data centers and cryptocurrency speculators and require ratepayers in those classes to commit to higher upfront charges and for a longer period of time than other energy-intensive consumers.[84] To justify the new data center class, AEP argued that data centers' unique size at individual locations and in the aggregate, as well as uncertainty about their energy use over the long-term and minimal employment opportunities, distinguish data centers from other energy-intensive consumers.[85] Data center companies responded that AEP had "failed to justify its approach to exclusively target data centers" and claimed that the utilities' costs to serve data centers was no different from other energy-intensive consumers that operate around the clock.[86] As of February 2025, the Ohio PUC has yet to rule on AEP's proposal.

FERC addressed similar issues in August 2024 when a utility proposed a new ratepayer class for energy-intensive cryptocurrency operations. Like AEP, the utility claimed that significant but uncertain demand growth justified approval of the new rate class, and therefore higher upfront payment commitments and longer terms for this new customer class were appropriate.[87] According to the utility, crypto speculators can more easily relocate their operations as compared to other energy-intensive consumers, and this mobility amplifies the risk of stranded assets built for new crypto customers that quickly set up shop elsewhere. FERC rejected the proposal because it found that the utility had provided insufficient evidence that new crypto operations "pose a greater stranded asset risk than other loads of similar size."[88] FERC's finding does not foreclose a utility from creating a crypto or data center ratepayer class, but instead signals that FERC will demand more persuasive evidence to justify approval of a new class.

State legislatures could remove any evidentiary hurdles by requiring large data centers to be in their own ratepayer class. With large data centers in their own class, regulators could more easily understand the effects data centers have on other ratepayers. For instance, parties might introduce evidence in a rate case showing how various cost allocation methods that raise costs for data centers would lower costs for other ratepayers. To avoid any claims of undue discrimination, the new rate class might include any new consumer above a specified capacity threshold that, as a practical matter, would likely capture only data centers.

Separating large data centers from other ratepayers could facilitate more protective cost allocation methods that better isolate data center costs from other ratepayers. Again, state legislatures might have a role to play. In Virginia, a bill proposed in January 2025 would require state regulators to determine whether cost allocation methods “unreasonably subsidize” data centers and to minimize or eliminate any such subsidies.[89] Such clear language would provide the PUC with guidance as it balances its obligations to protect ratepayers and facilitate growth in the state. In addition, it would force PUCs to revisit decades-old methods for dividing FERC-regulated transmission costs, as we discuss above.

As data centers shift to new tariffs, the largest potential cost shift in many states could be from the costs of new power plants built to meet data center growth. In most states, utilities are the dominant generation owners and can earn a PUC-set rate of return that they collect from ratepayers on their investments in new power plants. In general, utility expenses on new power plants are spread among ratepayer classes under the theory that all ratepayers benefit from the utility’s power plants. But the staggering power demands of data centers defy this assumption. Recent tariff proceedings highlight that many utilities are proposing schemes that are not adequately shielding ratepayers from the costs of new generation for data center growth.

In Indiana, the utility Indiana Michigan Power expects new data centers to increase the peak demand on its system from 2,800 to 7,000 megawatts.[90] To facilitate this growth, the utility proposed to create special terms for new customers that demand at least 150 megawatts of power, a threshold that in practice limits their applicability to new data centers.[91] Like AEP Ohio’s proposal, the updated tariff would require a new data center to commit to paying 90 percent of the utility’s costs of new generation and transmission capacity needed to meet the data center’s demand.[92] This 90 percent capacity payment and the tariff’s twenty-year term, according to the utility, would “provide reasonable assurance” that data centers’ payments to the utility “will reasonably align with the cost of the significant investments and financial commitments the Company will make to provide service.”[93]

Consumer advocates generally supported the utility's efforts to insulate ratepayers from data centers' energy costs but argued that the proposed terms were "insufficient for protecting existing customers from large potential cost shifts in the event of the closure" of a large data center.[94] One of their solutions was to "firewall" the costs of new power plants built to meet data center growth from other ratepayers by requiring the utility to separately procure or build generation for data centers, and then allocating all costs solely to data centers.[95] Consumer advocates also urged regulators to require other modifications related to contract termination and other provisions to protect ratepayers from stranded costs if data center growth failed to materialize or decreased following an initial spike.[96]

Data center companies argued the other side, claiming that the terms were too onerous and benefited the utility shareholders who "would be shielded from business risk, while reaping regulated returns on large potentially more risky expansion of rate base" that would be backed by data centers.[97] Amazon observed that the utility's proposed twenty-year term is based on the ordinary approach to cost recovery of utility capital investments. But instead of the utility building its own plants and earning a return on them, Amazon claimed that the utility could more efficiently support data center growth through short-term contracts with non-utility generators or purchases via PJM's regional markets.[98] Amazon argued that rather than "imposing virtually all risks" associated with power plant development on data centers and reaping all of the profits for itself, the utility should instead share the risks of infrastructure development with new data centers.[99]

The Indiana proceeding highlights how utility ownership of generation can exacerbate cost shifts that benefit utility shareholders. The traditional utility business model of decades-long cost recovery of new utility-owned power plants through consumer rates is not designed to address a near-term tripling of a utility's demand due to just a few giant energy-guzzling warehouses. While "firewalling" data centers' power plant costs from other ratepayers is a viable approach, regulators must ensure that utility proposals actually protect consumers.

Under its "Clean Transition Tariff," Nevada Energy claims to insulate other ratepayers from data centers' energy generation costs by contracting with new clean energy resources and then passing those contract costs directly to a specific data center or other customer. In theory, this arrangement could isolate generation costs, but public utility staff and other intervenors concluded that the new tariff would not actually firewall data centers' generation costs from other ratepayers.[100] They found that complex interactions between the new tariff's proposed pricing structure and existing tariffs would shift costs to other ratepayers. For instance, PUC staff focused on the utility's proposal to account for the revenue it would have earned if the data center took service under a standard tariff and then charge other ratepayers for a portion of its “lost” revenue.[101] In February 2025, the utility agreed with intervenors to modify its proposal and defer consideration of some of these complicated cost allocation issues.[102]

A better option for protecting ratepayers from power plant costs would be to allow data centers to purchase energy directly from non-utility retailers but still pay the utility for delivery service. Several states allow for such retail competition for energy-intensive consumers. To even further isolate data center energy costs, regulators could cut the cord entirely between the utility and data centers. Off-the-grid energy parks or energy parks that only export energy to the utility could completely insulate ratepayers from data centers’ energy costs.

C. Amend State Law to Require Retail Competition and Allow for Energy Parks

Competition can protect consumers from utility market power and insulate ratepayers from cost shifts. Starting in the 1970s, a few states began to allow limited competition for electricity service to certain energy-intensive consumers.[103] In the 1990s, about a dozen states permitted all ratepayers to shop for power supply while continuing to require them to pay state-regulated rates for utility-provided delivery service. Additional states allowed energy-intensive consumers to similarly choose a power supplier. To protect ratepayers, states could require new data centers to procure power through competitive processes rather than confining them to utility-supplied power. States could go further and allow or require new data centers to isolate entirely from the utility-owned network by creating new energy parks.

A mandate that new data centers procure power from non-utility suppliers would protect ratepayers from short-term costs and long-term risks. Requiring the data center to contract with a competitive supplier rather than with the utility would ensure that all stranded costs associated with the generation are allocated between the data center and its supplier. In addition, isolating the utility from the deal would obviate the need for the type of complex energy price calculations, integral to Nevada Energy’s proposal, that link the data center’s power price to the costs of the utility’s legacy assets.

The costs of utility-built power plants for data centers could be astronomical. In the Indiana proceeding discussed in the previous section, the utility’s own estimates revealed that if it met data center demand with self-built plants it could spend as much as $17 billion on new power plants over the next several years.[104] The utility’s proposal to require data centers to commit to paying 90 percent of the infrastructure costs over a twenty-year period would improve upon the status quo but would not completely isolate those costs from other ratepayers, particularly if data center demand did not meet the utility's forecasts.

Even with a state prohibition on new utility power plants for meeting data center demand, ratepayers could still face higher bills from cost shifts. A data center procuring energy from the market would still pay utility-imposed delivery charges that could obscure discounts for data centers or include various other cost shifts. Islanding the data center and its power supply from the utility-owned system is a sure-fire approach for protecting ratepayers.

An energy park, according to a recent paper by Energy Innovation, "combines generation assets, complementary resources like storage, and connected customers."[105] Unlike typical behind-the-meter arrangements where a customer installs some on-site generation to complement utility-delivered power, an energy park would provide sufficient power for the connected customers' operations. This arrangement is "particularly compelling for large customers due to the cost advantages of sourcing electricity directly from the cheapest, cleanest sources and due to the challenges of connecting large capacities to the existing grid."[106] Avoiding the protracted utility-run interconnection processes would be a benefit for Big Tech companies who tend to move faster than the lumbering utility industry.[107]

A fool-proof way to insulate utility ratepayers from data center energy costs is to isolate a data center energy park from the utility-owned network. Isolation may be difficult, however, as an interconnected energy park could be more financially attractive to developers, even if it is only able to export power to the transmission system and unable to import utility-delivered power.[108] Connecting an energy park would require a utility-run interconnection process and would likely lead to the utility imposing transmission charges on the energy park. While transmission charges associated with an export-only energy park could facilitate cost shifts, they are likely to be much smaller than those embedded in special contracts and other arrangements for serving data centers with utility-delivered power that we have outlined in this paper.

Both competitive generation and energy park development face the same legal obstacle: state protection of utility monopolies. Under many states' laws, an entity that delivers or sells power to another entity is a "public utility." For instance, if a generation company owns the park's generation assets and Big Tech company owns the data center, the generation company would be regulated as a public utility. This designation could doom the project. States typically prohibit competition for electric service and regulators and courts might enforce the state's monopoly protections by prohibiting a multi-owner energy park located within the territory assigned to the incumbent utility.[109] Even if a state allows the energy park to move forward as a public utility, the PUC may be compelled to regulate its rates and terms of service in a way that render the project unviable.

One potential workaround is to locate an energy park outside a for-profit utility's service territory. But states' laws may nonetheless impose obstacles. In Georgia, for instance, state law allows a new energy-intensive consumer located outside existing utility service territories to choose a supplier but limits the premises to a single customer.[110] An energy park in Georgia could therefore include only one data center owner. Energy parks might also be able to locate within the service territory of a municipal or cooperative utility. The service territories of these non-profit entities may not be protected by state law, or they may not be financially motivated to defend their monopolies and might instead welcome an energy park's investment in their communities.[111] That said, some non-profit utilities may regard an energy park as an infringement on their monopolies.[112]

State legislatures could amend anachronistic laws that prevent energy park development and block data centers taking utility service from procuring non-utility generation. To avoid interminable utility complaints that competition harms consumers,[113] laws could be tailored to apply only to data centers or other energy-intensive consumers that would otherwise require a utility to incur significant costs to procure power or build new generation.

D. Require Utilities to Disclose Data Center Forecasts

For competition to be effective, market participants need information about potential data centers' location and power demands. When utilities withhold that information, they prevent generators and other infrastructure and technology developers from offering data centers solutions that compete with the utility's offering. PUCs could require utilities to file monthly or quarterly load forecasts, which would reduce utilities' informational advantages and better enable other companies to offer solutions that would protect ratepayers from a utility's ability to shift data centers' costs to other consumers.

In the AEP Ohio proceeding, a trade association representing non-utility companies that sell electricity to consumers uncovered that AEP was withholding information. It documented that the utility's demand forecasts it filed in prior proceedings were inconsistent with its projections about data center growth it revealed to justify its data center tariff proposal.[114] The trade association's analyst explained that by holding back information AEP "conferred a *de facto* competitive advantage to build transmission rather than allowing a market response from competitive merchant generation" to meet data center demand.[115] The analyst also conjectured that AEP's concealment might directly harm ratepayers if it delayed development of generation that might be needed to meet growing regional demand, which could lead to increased prices in PJM's capacity auction.[116]

PUCs can order utilities to provide demand projections more frequently and specify that utilities include new energy-intensive consumers at various stages of development. Utilities could also provide potential locations and demands of new energy-intensive consumers with enough specificity to be useful to market participants but sufficiently obscured to protect consumers' potentially confidential business information. Because many utilities have substantially increased their demand forecasts over the past year,[117] new reporting rules would be well justified as a means of protecting consumers, enabling competition, and ensuring reliability.

E. Allow New Data Centers to Take Service Only if They Commit to Flexible Operations that Can Reduce System Costs

State regulators could require utilities to condition service to new data centers on a commitment to flexible operations. This approach could benefit all ratepayers by avoiding or reducing the need for expensive infrastructure that would otherwise be needed when a new data center increases the utility's maximum demand. A study by researchers at the Nicholas Institute for Energy, Environment & Sustainability estimates that 76 GW of data centers could connect to the system if utilities curtail energy delivery for just a few hours per year.[118]

As discussed above, utilities and RTOs plan power system expansion to provide sufficient capacity for meeting consumers' maximum energy demand, which usually occurs on the hottest and coldest days of the year. Because the system is planned for these extreme weather days, a large portion of a power system's generation and delivery infrastructure is underutilized for most of the year. If a data center commits to reducing its consumption of utility-supplied power during peak demand periods, utilities could deliver power to the data center without building new infrastructure.

To implement a flexibility mandate, PUCs could order utilities to modify their tariffs and classify data center loads as interruptible customers whose power can be turned off under specified circumstances. Similarly, regulators could also require utilities to modify their interconnection procedures to designate data centers as controllable loads that must reduce their consumption under certain conditions.[119] These strategies could defer the immediate need for costly infrastructure upgrades to serve new data centers. Utilities, however, have historically been hostile to regulatory attempts to require measures that would defer or avoid the need for costly infrastructure upgrades that drive utilities' profits.

IV. Subsidies Hidden in Utility Rates Extract Value from the Public

Utility rates have always been a means of achieving economic and energy policy goals. By financing favored investments through utility rates, rather than through general government revenue, policymakers can avoid having to raise taxes and instead conceal public spending through complex utility rate increases. From the public's perspective, hiding subsidies in utility rates may be acceptable if the benefits of the favored investments exceed their costs. For data centers deals, however, utilities do not publicly demonstrate that ratepayers pay lower rates as a result of the contract. To the extent data center development offers other benefits, such as expanding the local economy or advancing national security interests, we argue that these secondary effects are either already accounted for through other policies or irrelevant to utility regulators.

The economic harm to ratepayers from data center discounts extends beyond the short-term bill increases that utilities are imposing on the public. We are concerned that meeting data center demand is delaying opportunities to initiate power sector reforms that would benefit all ratepayers. To power new data centers, utilities are proposing more of the same: spending capital on large central-station power plants and transmission reinforcements. These types of projects have been fueling utility profits for generations, but the power sector today can do so much more. Deploying advanced technologies and adopting new operational and planning practices could squeeze more value from existing utility systems, but these low-capital-cost solutions are not profitable for utilities and therefore not pursued.[120] By approving special contracts for data centers and tariffs that do protect ratepayers from Big Tech's energy costs, PUCs may be inadvertently fostering an alliance between utilities and Big Tech that could reinforce the industry's technological status quo.

A. Data Center Subsidies Fail Traditional Benefit-Cost Tests

When a utility spends money to supply a new data center, the data center should pay for those investments. However, if ratepayers ultimately benefit from new infrastructure needed for a data center, it may be reasonable for the utility to charge ratepayers a portion of the costs. The "beneficiary pays" principle, an analogue of the cost causation standard, justifies short-term bill increases when they are offset by longer term benefits that reduce ratepayers' bills. Just as consumers should pay costs that reflect a utility's cost to serve them, a utility may charge consumers for projects that ultimately lower their rates.

PUCs have applied the beneficiary pays approach in numerous contexts. For example, many states fund energy efficiency programs through utility rates. These programs directly benefit the ratepayers that make use of the program's discounts for energy audits, new appliances, and other interventions that can reduce power use. All ratepayers are billed for these subsidies that flow directly to a handful of individual consumers that take advantage of these benefits. PUCs approve of this spending when programs ultimately lower peak system demand or otherwise reduce power system costs more than the costs of funding the efficiency program. We acknowledge, however, that these calculations are premised on assumptions and judgments and can be as imprecise as the cost allocation exercises we critique in this paper. The best regulators can do is conduct these analyses transparently, which allows for judicial review, limits the potential for arbitrary regulatory decisions, and provides a basis for changing the policy in response to new evidence.

In special contract proceedings, utilities and PUCs offer no such transparency about data center deals. Instead, billion-dollar contracts are proposed and approved without public accounting of the costs and benefits. Given the stakes and the incentives of the parties, the burden ought to be on utilities to prove publicly that ratepayers are benefiting from these deals, or at worst are being held harmless.

Ratepayers should not be saddled with costs due to data centers' purported strategic national importance. In January 2025, the Biden administration declared that AI is "a defining technology of our era" that has a "growing relevance to national security."[121] "Building AI infrastructure in the United States on the time frame needed to ensure United States leadership over competitors," according to the Biden administration, will "prevent adversaries from gaining access to, and using, powerful future systems to the detriment of our military and national security."[122] If this frightening scenario proves true — that AI will be a privately owned global weapon — it's not clear what it has to do with utility rates.

Data center proponents also tout the economic benefits of new development, but the public is already paying for local job growth through their taxes. Apart from discounted utility rates, many data centers separately receive generous state and local subsidies that governments rationalize based on the supposed economic and employment benefits of permitting new development. Several states, for instance, offer sales tax exemptions that allow data center companies to purchase computers, cooling equipment, and other components without paying state tax. In Virginia, the exemption saved data center companies nearly a billion dollars in 2023 alone.[123] Data centers may also benefit from one-off incentive packages. Mississippi is providing an Amazon data center with nearly $300 million of workforce training and infrastructure upgrades.[124] Mississippi will also reimburse Amazon for 3.15 percent of the data center construction costs and provide tax exemptions that could be worth more than $500 million. In lieu of taxes, Amazon will pay approximately $200 million in fees to the county over five years.[125]

B. Data Center Subsidies Interfere with Needed Power Sector Reforms

The power sector needs major upgrades. Investment in new high-voltage transmission is historically low,[126] despite an acute need for new power lines that can connect consumers to cheaper and cleaner sources of energy and improve network reliability.[127] With low interconnectivity, the utility industry is siloed into regional alliances that make little engineering or economic sense. Meanwhile, utilities have been sluggishly slow to adopt monitoring, communications, and computing technologies that can improve the performance of existing high-voltage networks.[128] At the local level, utilities are failing to unlock the potential of distributed energy resources to lower prices.[129]

Data center growth provides utilities with an excuse to ignore these inefficiencies. Utilities don't have to innovate to supply Big Tech's warehouses and are instead offering to meet data center demand with transmission reinforcements and gas-fired power plants, which have been the industry's bread-and-butter for decades. Some utilities are even propping up their oldest and dirtiest power plants to meet data center demand.[130] Neither data centers nor regulators are challenging utilities to modernize their systems.

Power sector stagnation is the fault of utilities and the regulatory construct that incentivizes inefficient corporate decisions. Rate regulation enables excessive utility spending that crowds out cheaper alternative investments. Because they are monopolists, utilities do not face competition that might expose their inefficiencies. Regulated rates rarely punish utilities for inefficiencies or reward them for improving their operations through low-cost technologies. Ultimately, regulators must try to align utility performance with consumers' interests, but achieving this straightforward objective is dauntingly complex.

Data center growth now overwhelms many PUC agendas. By law, regulators must respond to utility proposals about rate increases, special contracts, infrastructure development, and other issues. Utilities' messaging to regulators and investors is that meeting data centers' growth targets is an urgent priority. The implication is that there's no time to act differently. With utilities' push for growth dominating their dockets, PUCs may find it even harder to reform inefficient utility practices and block unneeded investments. For ratepayers, beneficial projects will remain unfunded, and wasteful utility practices will persist.

As utilities wring profits from the public through special contract approvals, they may be developing a new alliance with Big Tech. Uniting utilities' influence-peddling experience with the deep pockets of Big Tech could further entrench utility control over the power sector. Utilities are already among the largest donors to state elected officials and have a century of experience navigating state legislatures and agencies to protect their monopoly control and otherwise advance their interests. A long-term partnership to push the common interests of utilities and data centers at statehouses, PUCs, and other forums could undermine reform efforts and harm ratepayers.

While energy-intensive consumers typically have a financial incentive to participate in PUC proceedings and argue for their own self-interest by opposing wasteful utility spending, we are concerned that a different scenario may play out for data centers. If utilities' growth predictions are realized, some utilities will have invested billions of dollars to serve data centers that will consume *a majority of all power* delivered by the utility. Under this scenario, the utility will be dependent on its data center customers for revenue and will need to retain them in order to justify its prior and future expansion. To prevent data center departures and attract new data center customers, utilities might continue to offer discounted rates. Rather than acting as watchdogs in PUC proceedings, data center companies may instead focus on securing more discounts. Insulated by special contract deals and favorable tariffs with friendly utilities, data center companies would focus on defending their discounts rather than disciplining the utility's spending in rate cases.

Outside of formal proceedings, utility-Big Tech alliances could amplify pro-utility political messages. Utilities have a pecuniary interest in the laws that govern PUC decisionmaking and push for changes that benefit their bottom lines. Utilities formally lobby state legislators and also pursue an array of public relations strategies to secure favorable legislative and regulatory outcomes. Big Tech has the financial capacity to significantly increase the amount of money supporting of pro-utility bills and regulatory actions.

An alternative approach — which requires data centers to power themselves outside of the utility system — sets up a formidable counterweight to utilities' monopoly power. If Big Tech is forced to power itself, it might defend against utility efforts to limit competition and return to the pro-market advocacy that characterized the Big Tech's power-sector lobbying efforts prior to the ChatGPT-inspired AI boom.

Appendix A

Big Tech Companies and Data Center Developers Testifying that Utility Prices Inform Where They Build New Facilities

- AEP Ohio Proposed Tariff Modifications, *supra* note 2, Motion to Intervene and Memorandum in Support of Sidecat, an Affiliate of Meta (Jun. 10, 2024) ("The applicable electricity rates and corresponding electric service tariffs for AEP Ohio will be a significant consideration for Meta when evaluating possible sites for new facilities, expansions at existing facilities, and otherwise operating its data center assets.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz in Opposition of the Second Joint Stipulation and Recommendation, at 4 (Nov. 8, 2024) ("the terms and conditions in Schedule DCT are far more restrictive and burdensome than those imposed by investor-owned utilities in other states, which could prompt some data center customers to consider investing outside of Ohio").
- AEP Ohio Proposed Tariff Modifications, Second Supplemental Direct Testimony of Michael Fradette, on Behalf of Amazon Data Services, Inc., at 18 (Nov. 8, 2024) ("By rejecting a stipulation that unfairly discriminates against data centers, the Commission can help ensure that Ohio continues to be a leader in attracting investment from this vital industry.").
- AEP Ohio Proposed Tariff Modifications, Motion to Intervene of Data Center Coalition, at 4 (May 24, 2024) ("AEP Ohio's proposals, and potential proposals made by intervenors in the case, may have a significant impact on existing and planned data centers in AEP Ohio's service territory.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz, at 11 (Oct. 18, 2024) ("If AEP Ohio's proposal is adopted, it would create an unfavorable environment for data center development in the state, potentially causing companies to reconsider their investment plans.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 (Oct. 18, 2024) ("If approved, the DCP tariff will adversely impact planned data center development in the Company's service territory."); *id.* at 11 ("At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms.").
- Indiana Michigan Power Proposed Tariff Modification, *supra* note 15, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 6 (Oct. 15, 2024) ("If

approved, the IP Tariff changes could adversely impact planned data center development in the Company's service territory.").

- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Justin B. Farr on behalf of Google, at 23 (Oct. 15, 2024) ("Modifications . . . have the potential to limit opportunities for . . . the development of shared solutions that can provide significant benefit to I&M's system by removing the financial incentive for I&M to collaborate with its customers to pursue innovative solutions to support their growth.").
- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Michael Fradette on behalf of Amazon Data Services, Inc., at 37 (Oct. 15, 2024) ("The proposed [tariff] is not reasonable and in fact has a negative impact on Amazon's view for future investment actions within I&M's service territory. I&M has offered no reasonable justification for revising Tariff I.P. as proposed.").
- Contracts for Provision of Electric Service to a New Large Customer's Minnesota Data Center Project, Minn. Pub. Util. Comm'n Docket No. 22-572, Petition, at 28 ("The customer has made clear that the CRR Rate is critically important to its decision to select a site in Minnesota for its new data center. Without the CRR Rate, the economic feasibility of this new data center would be jeopardized.").
- In re Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract, Pub. Util. Comm'n of Colorado Proceeding No. 23A-0330E, Direct Testimony & Attachment of Travis Wright on behalf of Quality Technology Services, at 8 (Jun. 23, 2023) ("QTS selects its new locations extremely carefully. Electricity is one of the major costs to operating a data center, so the low EDR rate provided by Public Service, and the term of the EDR agreement, is a critical factor in determining to locate in Aurora."); *id*. at 10–11 ("Given that approximately 40 percent of the Aurora QTS Campus's operational expense will be attributable to utilities, with electric being the largest component, the cost per kWh can easily make or break a project, or drive QTS or its customers to invest resources elsewhere. The EDR ESA that we have negotiated with Public Service and are requesting approval of in this Proceeding, is a critical component of our business model for the Aurora QTS Campus."); *id*. at 16 ("Was the cost of electricity a critical consideration for QTS in deciding where to site its new operations? Yes. 40 percent of the operational cost of a data center is electricity, and this will usually be the largest line item on the budget. Additionally, this cost will continue for 40 years, and will scale the business. In contrast, real estate and development costs are one-time, up-front expenditures that are watered down as the

volume of business increases. The largest and fastest growing operations in our portfolio are in markets where electricity costs are competitive.”).

- In re Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement, Pub. Util. Comm’n of Ohio Case No. 23-0891-EL-AEC, Joint Application, at 7 (Sep. 28, 2023) (“Without this reasonable arrangement, NADC could construct its own dedicated substation and take lower-cost service under AEP Ohio’s transmission voltage tariff – to the extent it would decide to develop its facilities in AEP Ohio’s service territory.”).
- Application of Nevada Power Company for Approval of an Energy Supply Agreement with Lumen Group, Pub. Util. Comm’n of Nev. Docket No. 19-12017, Application, Attachment A: Long Term Energy Supply Agreement White Paper, at 17 (Dec. 19, 2019) (“The ESA provides Google with important benefits . . . the blended rate provided for in the ESA is cost-effective and competitively priced compared to other available options, the fixed-price nature of the agreement provides Google with important cost-certainty into its energy expenditures . . .”).

Endnotes

* Eliza Martin is a Legal Fellow in the Environmental and Energy Law Program at Harvard Law School. Ari Peskoe is the Director of the Electricity Law Initiative. We thank Kent Chandler, Josh Macey, Abe Silverman, and Megan Wachspress for thoughtful feedback on our draft.

[1] *See, e.g.*, JOHN D. WILSON, ZACH ZIMMERMAN & ROB GRAMLICH, STRATEGIC INDUSTRIES SURGING: DRIVING US POWER DEMAND 8 (Grid Strategies, Dec. 2024) [hereinafter Grid Strategies Report]; Alastair Green et al., *How Data Centers and the Energy Sector Can Sate AI's Hunger for Power*, MCKINSEY & CO., ("Much of data center growth — about 70 percent — is expected to be fulfilled directed or indirectly (via cloud services, for instance) by hyperscalers by 2030"); EPRI, POWERING INTELLIGENCE: ANALYZING ARTIFICIAL INTELLIGENCE & DATA CENTER ENERGY CONSUMPTION 7 (May 2024) [hereinafter Powering Intelligence]; Jennifer Hiller & Katherine Blunt, *Inside the Audacious Plan to Reopen Three Mile Island's Nuclear Plant*, WALL ST. J. (Nov. 10, 2024), ("Analysts at Jefferies estimate Microsoft will pay between $110 and $115 per megawatt hour of electricity").

[2] *See, e.g.*, In re *Application of Ohio Power Company for New Tariffs Related to Data Centers*, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 ("If approved, the [proposed] tariff will adversely impact planned data center development in the Company's service territory."); *id.* at 11 ("At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms."). *See* Appendix A for additional evidence.

[3] *See, e.g.*, Rich Miller, *Skybox Plans 300-Megawatt Campus South of Dallas*, DATA CENTER FRONTIER (Nov. 20, 2023); City of Cleveland, Office of Sustainability & Climate Justice (noting that the city has a 300-megawatt system).

[4] Palo Verde is the largest nuclear power station in the U.S. Its three reactors produce approximately 3.3 gigawatts. Meta announced a two-gigawatt data center development in December 2024. *See* Dan Swinhoe & Zachary Skidmore, *Meta Announces 4 Million Square Foot, 2 GW Louisiana Data Center Campus*, DATA CENTER DYNAMICS (Sep. 5, 2024).

[5] *See generally* Powering Intelligence; Alastair Green et al., *How Data Centers and the Energy Sector Can Sate AI's Hunger for Power*, MCKINSEY & CO.

[6] *See, e.g.*, Grid Strategies Report ("[A]nnual peak demand growth will average 3% per year over the next five years. While 3% growth may seem small to some, it would mean six times the planning and construction of new generation and transmission capacity.").

[7] *See* FED. ENERGY REG. COMM'N, SUMMER ENERGY MARKET & ELECTRIC RELIABILITY ASSESSMENT 46 (May 23, 2024) (showing 19 GW actual demand in 2023); Newmark, 2023 U.S. DATA CENTER MARKET OVERVIEW & MARKET CLUSTERS 7 (Jan. 2024) (projecting 35 GW in 2030); *AI is Poised to Drive 160% Increase in Data Center Power Demand*, Goldman Sachs (May 14, 2024).

[8] *See* Grid Strategies Report, at 12.

[9] *See* Georgia Power Company, Georgia Pub. Serv. Comm'n Docket No. 56002, Budget 2025: Load and Energy Forecast 2025 to 2044 (Jan. 31, 2025); Drew Kann and Zachary Hansen, *Data Centers Use Lots of Energy: Georgia Lawmakers Might Make Them Pay More*, THE ATLANTA JOURNAL CONSTITUTION (Feb. 13, 2025) (stating that Georgia Power executives stated that 80 percent of the company's forecasted electricity demand growth is due to data centers).

[10] Press Release, *Oncor Electric Delivery Company, Oncor Reports Third Quarter 2024 Results* (Nov. 6, 2024),.

[11] Robert Walton, *ERCOT Successfully Navigates Heat Wave, New Peak Demand Record*, UTILITY DIVE (Aug. 26, 2024).

[12] *See* Ethan Howland, *AEP Faces 15 GW of New Load, Driven by Amazon, Google, Other Data Centers: Interim CEO Fowke*, UTILITY DIVE (May 1, 2024); American Electric Power, 4th Quarter Earnings Presentation (Feb. 13, 2025).

[13] See, e.g., In re Application of Ohio Power Company for New Tariffs Related to Data Centers, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Matthew S. McKenzie on Behalf of Ohio Power Company [hereinafter Ohio Power Company Testimony], at 2 (May 13, 2024)

[14] Indeed, investors are taking note. The authors have on file numerous reports from utility stock analysts that tout the potential of data center growth. Utilities' presentations to investors claim that data center growth will drive future earnings. *See, e.g.,* AEP 4th Quarter Earnings Presentation, *supra* note 13, at 13 (stating that "Load Growth Supports Financial Strength" and noting it is being driven by data centers).

[15] *See, e.g.*, In re *Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Tariff*, Indiana Util. Reg. Comm'n Cause No. 46097 [hereinafter Indiana Michigan Power Proposed Tariff Modifications], Testimony of Indiana Consumer Advocates, at 4 (Oct. 15, 2024) ("There has been a significant lack of transparency with these new loads . . . For example, with respect to new large loads coming to I&M's service territory, Google and Microsoft refused to answer CAC data requests about their anticipated load and electricity consumption, and Microsoft also refused to identify its forecasted load factor. CAC counsel reached out to counsel to these parties and requested to execute a non-disclosure agreement with each respective company so that CAC could obtain this pertinent information, but thus far, we have not received a proposed non-disclosure agreement or the confidential information."). Most of the figures in the Georgia Power filing cited at note 9 are redacted.
[16] *See, e.g.*, AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, *supra* note 13, at 2 ("Currently, AEP Ohio has limited ability to distinguish customers who are merely speculating on potential data center investments from customers who are willing to make long-term financial *commitments* to data center investments.") (original emphasis); *Large Loads Co-Located at General Facilities Technical Conference*, FERC Docket No. AD24-11-000, Transcript, at 26 (Aubrey Johnson, Vice-President, Systems & Resource Planning for the Midcontinent Independent System Operator explaining that "in many cases, these data centers are showing up in multiple places, so I have many members submitting loads that are all the same. So how do we have more clarity . . . to understand what the actual true load is?").
[17] *See generally* Powering Intelligence, at 7.
[18] *See, e.g.*, David Uberti, *AI Rout Sends Independent Power Stocks Stumbling*, WALL ST. J. (Jan. 27, 2025), ("DeepSeek's efficient approach have 'created panic among investors who question the sustainability of US data center and AI investments,' Guggenheim analysts wrote in a note"); JONATHAN KOOMEY, TANYA DAS & ZACHARY SCHMIDT, ELECTRICITY DEMAND GROWTH AND DATA CENTERS: A GUIDE FOR THE PERPLEXED (Bipartisan Policy Center & Koomey Analytics, Feb. 2025).
[19] The Grainger College of Engineering, *Why DeepSeek Could be Good News for Energy Consumption*, (Feb. 6, 2025); James O'Donnell, *DeepSeek Might Not be Such Good News for Energy After All*, MIT TECH. REVIEW (Jan. 31, 2025).
[20] *See* Deepa Seetharaman and Tom Dotan, *Tech Leaders Pledge Up to $500 Billion in AI Investment in the U.S.*, WALL ST. J. (Jan. 21, 2025).
[21] Jordan Novet, *Microsoft Expects to Spend $80 Billion on AI-Enabled Data Centers in Fiscal 2025*, CNBC (Jan. 3, 2025).
[22] Press Release, State of Ohio, *Governor DeWine Announces $10 Billion Investment Plan from Amazon Web Services in Greater Ohio* (Dec. 16, 2024).
[23] Dan Swinhoe & Zachary Skidmore, *Meta Announces 4 Million Sq Ft, 2 GW Louisiana Data Center*, DATA CENTER DYNAMICS (Dec. 5, 2024).
[24] *See generally* Aneil Kovvali & Joshua C. Macey, *Hidden Value Transfers in Public Utilities*, 171 PENN. L. REV. 2129 (2023).
[25] KEN COSTELLO, ALTERNATIVE RATE MECHANISMS & THEIR COMPATIBILITY WITH STATE UTILITY COMMISSION OBJECTIVES, NATIONAL REGULATORY RESEARCH INSTITUTE 2 (Apr. 2014).
[26] See U.S. Energy Information Administration, *Electric Power Monthly, Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector* (showing average residential, commercial, and industrial rates in each state).
[27] Alabama Elec. Co-op., Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982).
[28] Co. Interstate Gas Co. v. Fed. Power Comm'n, 324 U.S. 581, 590 (1945).
[29] JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 338 (1961).
[30] *See, e.g.,* Off. of Consumer Counsel v. Dep't of Pub. Util. Control et al., 905 A.2d 1, 6 (Conn. 2006) ("In the specialized context of a rate case, the court may not substitute its own balance of the regulatory considerations for that of the agency, and must assure itself that the [department] has given consideration of the factors expressed in [the statute]."); Iowa-Ill. Gas & Elec. Co. v. Ill. Com. Comm'n, 19 Ill. 2d 436, 442 (Ill. 1960) (explaining that deference to the Commission is "especially appropriate in the area of fixing rates"); Farmland Ind., Inc. v. Kan. Corp. Comm'n, 37 P.3d 640, 650 (Kan. App. 2001) (providing that the Kansans Corporation Commission "has broad discretion in making decisions in rate design types of issues"); Ohio Consumers' Counsel v. Pub. Util. Comm'n, 926 N.E.2d 261, 266 (Ohio 2010) ("The lack of a governing statute telling the commission how it must design rates vests the commission with broad discretion in this area.").
[31] *See 2024 FERC Rep. on Enforcement*, FERC Docket No. AD07-13-018, at 51 (Nov. 21, 2024) ("Most audits find that public utilities recorded non-operating expenses and functional operating and maintenance expenses

in [Administrative and General] expense accounts, leading to inappropriate inclusion of such costs in revenue requirements produced by their formula rates"); *see also infra* note 34.
[32] *FirstEnergy Corp.,* FERC Docket No. FA19-1-000, Audit Report, at 48 (Feb. 4, 2022).
[33] *Id.* at 16.
[34] *See, e.g.*, *Application of Southern California Gas Company for Authority to Update its Gas Revenue Requirement and Bas Rates*, California Pub. Util. Comm'n Application 22-05-015, Decision 24-12-074, at 7 (Dec. 19, 2024) ("The decision [to use one-way balancing accounts] highlights a pattern of misclassification of costs at Sempra Utilities, where the company has charged ratepayers for lobbying, political activities, and expenses related to outside legal firms. These costs have been improperly booked as above-the-line expenses when forecasting future costs."); *Order Instituting Rulemaking*, California Pub. Util. Comm'n Rulemaking 13-11-005, Decision 22-04-034 (Apr. 7, 2022) ("As an experienced utility, SoCalGas should have known that its billing of lobbying against reach codes implicates several basic legal principles that are central to its duties to the Commission and to customers . . . Thus, aside from billing ratepayers for lobbying contrary to the intent of the Commission, SoCalGas appears on the face of the record to have misled staff about the direction of its lobbying…."). *See also 2024 FERC Rep. on Enforcement*, FERC Docket No. AD07-13-018, at 58 (Nov. 21, 2024) (summarizing that FERC audits revealed "improper application of merger-related costs; lobbying, charitable donation, membership dues, and employment discrimination settlement costs; improper labor overhead capitalization rates….").
[35] Costello, *supra* note 25, at 44. *See also Investigation into the Reasonableness of Rates & Charges of PacifiCorp*, Utah Pub. Serv. Comm'n Docket No. 99-035-10, 2000 WL 873337 (2000) ("[E]ach class of service does not pay precisely its 'share' of costs. This is true, for example, of the large customer groups, or special contract customers, according to some views of allocations.").
[36] *See, e.g.*, MINN. STAT. § 216B.162, subd.7 (2024); COLO. REV. STAT. ANN. § 40-3-104.3 (West 2018); MICH. COMP. LAWS § 460.6a(3).
[37] KAN. STAT. ANN. § 66-101i.
[38] *See* MISS. CODE ANN. § 77-3-271(3) ("A public utility may enter into a large customer supply and service agreement with a customer, which may include terms and pricing for electric service without reference to the rates or other conditions that may be established or fixed under Title 77, Chapter 3, Article 1, Mississippi Code of 1972. No approval by the commission of such agreement shall be required. With respect to such an agreement…the agreement, including any pricing or charges for electric service, shall not be subject to alteration or other modification or cancelation by the commission, for the entire term of the agreement….").
[39] *See* Appendix A.
[40] *See, e.g.*, *Application of El Paso Electric Company for an Economic Development Rate Rider for a New Data Center*, Pub. Util. Comm'n Texas Docket No. 56903, Order No. 1 (Aug. 2, 2024) (issuing standard protective order with no analysis); *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm'n Cause No. 45975, Order (Nov. 20, 2023) (granting Duke Energy's motion for confidential treatment); In re *Cheyenne Light, Fuel & Power Co. Petition for Confidential Treatment of a Contract with Mineone Wyoming Data Center LLC*, Wyoming Pub. Serv. Comm'n Docket No. 20003-238-EK-24 (Record No. 17600), Letter Order (Oct. 9, 2024) (authorizing confidential treatment); In re *Xcel Energy's Petition for Approval of Contracts for Provision of Service to a New Large Customer's Minnesota Data Center Project*, Minn. Pub. Util. Comm'n Docket No. E-002/M-22-572, Order (excising significant portions of the proposed service agreement and staff analysis because it is a "highly confidential trade secret"); *Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm'n Case No. 2022-00387, Order (Dec. 4, 2024), at 3 (granting confidential treatment for utility filing and providing that the information "shall not be placed in the public record or made available for public inspection for five years or until further order[ed]").
[41]*See id; see also* Daniel Dassow, [*University of Tennessee Professor Sues TVA for Records of Incentives to Bitcoin Miners*](), KNOXVILLE NEWS SENTINEL (Oct. 29, 2024) (explaining how there was no information about the incentives that TVA gave a cryptocurrency company to build within its footprint, but that the company used 9.4 percent of all Knoxville Utilities Board electricity in 2023 while employing just thirty people).
[42] *See* Costello, *supra* note 25, at 21.
[43] *See* Peter Lazare, *Special Contracts and the Ratemaking Process*, 10 ELEC. J. 67, 68–70 (1997) (quoting a Commonwealth Edison filing that argues long-run costs are appropriate for rate cases and short-term costs are appropriate for special contract proceedings and explaining the implications of using different metrics).
[44]*See, e.g.*, In re *Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement*, Pub. Util. Comm'n of Ohio Case No. 23-0891-EL-AEC, Order Approving the Application with Modification ("The proposed arrangement meets the burden of proof for obtaining a

reasonable arrangement under Ohio Adm. Code Chapter 4901:1-38. Furthermore, we find that the proposed arrangement, as modified by Staff, is reasonable and should be approved.”). Occasionally, a state PUC applying its public interest standard will gesture at a utility’s static marginal cost analysis or no-harm analysis for analytical support. *See, e.g.*, *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm’n Cause No. 45975, Order of the Commission (Apr. 24, 2024) (“In making such a determination [that the proposed agreement satisfies Indiana Code], two considerations are important: whether the rates negotiated between the utility and its customer are sufficient for the utility to cover the incremental cost of providing the service to the customer and still make some contribution to the utility’s recovery of its fixed costs, and whether the utility has sufficient capacity to meet the customer’s needs. As explained by [Duke Energy’s Vice President of Rates and Regulatory Strategy], the Agreement requires that Customer cover the incremental costs of providing service to it, as well as contributing to Petitioner’s recovery of fixed costs…Based on the evidence of record, we find and conclude that the terms and conditions contemplated in the Agreement are just and reasonable…Therefore, we find that the Agreement is in the public interest and is, therefore, approved….”); In re *Idaho Power Company’s Application for Approval of a Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC’s Data Center Facility*, Idaho Pub. Util. Comm’n Case No. IPC-E-21-42, Order No. 35958 (“Commission Discussion and Findings: The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502, and -503…We have reviewed the record in this case and find the Company’s August 30, 2023, Filing including an amended ESA, revised Schedule 33, and additional modifications is consistent with the Commission’s directive in Order No. 3577.”).

[45] See Duke Energy Carolinas, LLC v. NTE Carolinas II, LLC, 111 F.4th 337, 344–46 (4th Cir. 2024).

[46] *Id.* at 347.

[47] *Id.* at 349.

[48] *See* Appendix A.

[49] *See generally* Kovvali & Macey, *supra* note 24.

[50] Cross-Subsidization Restrictions on Affiliate Transactions, 73 Fed. Reg. 11,013 (2008) (codified at 18 C.F.R. pt. 35).

[51] *See, e.g.,* Nantahala Power & Light Co. v. FERC, 476 U.S. 953 (1986).

[52] *See, e.g.*, Nat’l Ass’n of Reg. Util. Comm’rs v. FERC, 475 F.3d 1227, 1285 (D.C. Cir. 2007); Entergy Services, Inc. v. FERC, 319 F.3d 536 (D.C. Cir. 2003); South Carolina Pub. Serv. Auth. V. FERC, 762 F.3d 41 (D.C. Cir. 2014).

[53] PJM, *PJM Board of Managers Approves Critical Grid Upgrades*, PJM INSIDE LINES (Dec. 11, 2023).

[54] Sami Abdulsalam, Senior Manager, PJM Transmission Planning, Reliability Analysis Update at Transmission Expansion Advisory Committee Meeting (Dec. 5, 2023). *See also PJM Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades*, FERC Docket No. ER24-843, Protest and Comments of Maryland Office of People’s Counsel (Feb. 9, 2024) [hereinafter Maryland People’s Counsel Protest].

[55] *See generally PJM Interconnection*, 187 FERC ¶ 61,012 at P 6 (2024); Maryland People’s Counsel Protest, Affidavit of Ron Nelson, at 5.

[56] *See* Maryland People’s Counsel Protest, Affidavit of Ron Nelson, at 5.

[57] *See Delmarva Power & Light Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm’n Case No. 8890, Revised Tariff, Attachment E (Jul. 2, 2024) (allocating 68 percent of transmission costs to residential customers); *Potomac Electric Power Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm’n Case No. 8890, Revised Tariff, Attachment F (Jul. 2, 2024) (allocating 53 percent of transmission costs to residential customers); *Baltimore Gas & Elec. Co. Updated Market-Priced Service Rates, Administrative Charges, and Retail Transmission Rates under Rider 1*, Maryland Pub. Serv. Comm’n Case Nos. 9056/9064, Attachment 2: Development of the Retail Transmission Rates (Apr. 30, 2024) (allocating 78 percent of transmission costs to residential customers).

[58] *Application of Virginia Electric and Power Co.*, Virginia Corp. Comm’n. Case No. PUR-2021-00102, Report of Chief Hearing Examiner Alexander F. Skirpan, Jr., at 9–10 (Jul. 14, 2021).

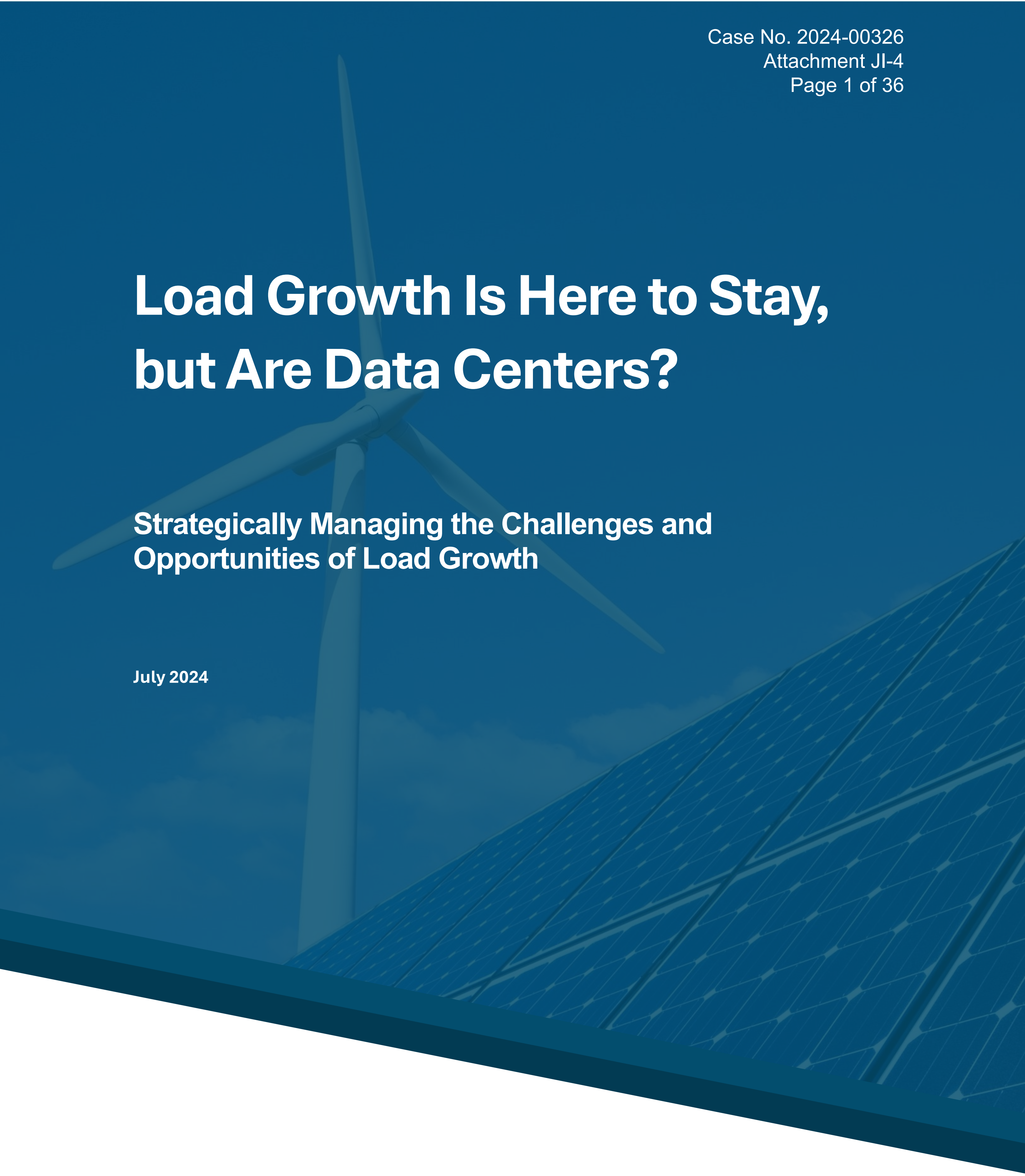
[59] The cost causation principle could require a shift from transmission rates based on average — or static marginal — costs, to dynamic marginal cost analyses. *See* In re *Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract*, Colorado Pub. Util. Comm’n Proceeding No. 23A-0330E, Commission Decision Denying Exceptions to Decision No. R24-0168 and Adopting Recommended Decision with Modifications, at 11–12 (May 15, 2024) (“[W]e emphasize that the Commission’s review of future Non-Standard EDR contracts must entail detailed examination of how the addition of large loads to the Public Service’s system may create a dynamic need for multi-billion new generation and transmission capacity investments that unpredictably show up with no meaningful notice to this Commission and may not be easily

captured in a static marginal cost analysis . . . To that end, the marginal cost analysis that Public Service applied to the EDR ESA with [the data center customer] may not be adequate in future proceedings where the Commission reviews a similar Non-Standard EDR contract especially in light of the rapidly evolving and dynamic interaction between rising demand and the potential costs of serving that growth.").
[60] *Application of Virginia Electric Power,* Virginia Corp. Comm'n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 47 (Feb. 14, 2025).
[61] *Application of Virginia Electric Power,* Virginia Corp. Comm'n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 23 (Feb. 14, 2025).
[62] *Supra* note 58.
[63] *See* AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 18–20 (May 13, 2024).
[64] *See* AEP Ohio Proposed Tariff Modifications, Prepared Direct Testimony of Dennis W. Bethel on Behalf of Buckeye Power, Inc. and American Municipal Power [hereinafter Buckeye Power Comments], at 18–19 (Aug. 29, 2024).
[65] *Dayton Power & Light Co.*, 189 FERC ¶ 61,220 (2024).
[66] *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Protest of the Office of the Ohio Consumers' Counsel [hereinafter Protest of the Office of Ohio Consumers' Counsel], at 4 (Nov. 13, 2024); *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Limited Comments of Buckeye Power (Nov. 21, 2024).
[67] Protest of the Office of the Ohio Consumers' Counsel at 5.
[68] *Dayton Power and Light Co.*, 189 FERC ¶ 61,220 at P 23 (2024).
[69] *PJM Interconnection and Virginia Electric and Power Company*, 169 FERC ¶ 61,041 (2019).
[70] *See, e.g.,* Walker Orenstein, *Amazon Wants to Limit Review of 250 Diesel Generators at Its Minnesota Data Center,* MINNESOTA STAR TRIBUNE (Feb. 17, 2025) (noting that Amazon wants to install 600 megawatts of on-site diesel-powered generators at its new data center).
[71] *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Complaint Requesting Fast Track Processing of Constellation Energy Generation, LLC [hereinafter Constellation Complaint], at 20–21 (Nov. 22, 2024).
[72] *Constellation Energy Generation v. PJM*, Docket No. EL25-20, Exelon Comments in Opposition to the Complaint, at 3 (Dec. 12, 2024) ("Constellation refers to Co-Located Load as being 'Fully Isolated' and repeats that term again and again, but it remains untrue. If the loads at issue were truly 'isolated,' the PJM Tariff would not apply to them; no FERC-jurisdictional tariff would. And there would be no reason for this proceeding. As further discussed . . . the loads — whether they are what Constellation labels 'fully isolated' or not — unavoidably rely upon and use grid facilities and grid services in multiple ways. As a matter of physics and engineering, the load is fully integrated with the electric grid — this is the opposite of 'Fully Isolated.'").
[73] *See, e.g.*, *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 12–13 (Dec. 12, 2024); *Large Loads Co-Located at General Facilities*, FERC Docket No. AD24-11-000, Post Technical Comments of the Organization of PJM States, Inc., at 4 (Dec. 9, 2024) (stating that "[t]ransmission customers have paid the costs of supporting the grid necessary to allow [ ] nuclear facilities to operate").
[74] *PJM Interconnection, LLC*, FERC Docket No. ER24-2172 [hereinafter Susquehanna Nuclear Interconnection Agreement], Protest of Exelon Corporation & American Electric Power Service Corporation, Declaration of John J. Reed & Danielle S. Powers, at 4 (Jun. 24, 2024).
[75] Susquehanna Nuclear Interconnection Agreement, Motion for Leave to Answer and Answer of Constellation Energy Generation and Vistra Corp., at 11 (Jul. 10, 2024).
[76] *See* PJM, *2025/2026 Base Residual Auction Report*, at 11 (2024).
[77] *See* *2024 Quarterly State of the Market Report for PJM: January Through September*, MONITORING ANALYTICS 3 (2024). *See also* Buckeye Power Comments, at 15 (Aug. 29, 2024) ("Co-location of data centers at existing multi-unit generators (nuclear plants are considered ideal) appears, at first blush, to be attractive as it can 'free-up' transmission capacity by reducing the net output of the generators that the transmission system must deliver. But co-location is a complicated scenario that can disrupt power markets and shift costs by removing large blocks of reliable base load power that will need to be replaced by other sources that will likely require transmission expansion elsewhere."); *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 3–4 (Dec. 12, 2024) ("The OAG's primary concern regarding co-location arrangements is the impact on resource adequacy and electricity energy and capacity prices . . . . The effect of removing the Illinois nuclear power plant capacity from the ComEd zone and from the PJM market generally can be expected to drive up prices . . . . In light of these multiple factors that are currently putting pressure on prices, co-location arrangements that reserve large blocks of power for discrete customers and prevent them from serving the grid as a whole can be expected to affect the 2027/2028 [capacity prices] . . .

. The OAG is concerned that co-location arrangements that abruptly remove large resources with high capacity values from the grid will cause further devastating price increases while the PJM markets struggle to respond.").
[78] *See infra* Section III.C.
[79] *See Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Constellation Complaint, at 6–7 (Nov. 22, 2024) ("competition to serve data center loads [is] a threat to [utilities] bottom line").
[80] *Id.* ("Exelon's utilities already have taken the position that this Commission has decreed that Fully Isolated Co-Located Load is 'impossible' — and shut down any attempt by customers to co-locate data center load in their utility systems. As detailed in their petition for declaratory order filed in Docket No. EL24-149, Exelon is refusing to process necessary studies on these grounds, demanding expensive upgrades under their unified interconnection procedures, delaying agreed-upon work which will force a nuclear plant to take additional outages, and forcing additional services to be procured.").
[81] *See PJM Interconnection, LLC*, 190 FERC ¶ 61,115 (Feb. 20, 2025) (instituting a show cause proceeding pursuant to section 206 of the FPA, and directing PJM and the Transmission Owners to either (1) show cause as to why the Tariff "remains just and reasonable and not unduly discriminatory or preferential without provisions addressing the sufficient clarity or consistency the rates, terms, and conditions of service that apply to co-location arrangements; or (2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential, and therefore, proceeds to establish a replacement Tariff").
[82] *See In the Matter of: Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm'n Case No. 2022-00387, at 2–4 (Aug. 28, 2023) (citing *Investigation into the Implementation of Economic Development Rates by Electric & Gas Utilities,* Kentucky Pub. Serv. Comm'n Admin. Case No. 327 (Sep. 24, 1990), *aff'd*, Kentucky Power Co. v. PSC of Kentucky, Franklin Circuit Court, Div. 1, Civil Action No. 23-CI-00899 (Dec. 30, 2024)).
[83] *Id.*
[84] *See* AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 2 (May 13, 2024). AEP Ohio requested PUC approval to create two new customer classifications: data centers with a monthly maximum demand of 25 MW or greater, and mobile data centers (cryptocurrency miners) with a monthly maximum demand of 1 MW or greater. AEP's proposed tariff would include new obligations for these customer classes, including a minimum demand charge of 90 percent for data centers, and 95 percent for cryptocurrency facilities, as opposed to the standard 60 percent minimum demand charge for other customers in the general service rate class. AEP Ohio would also require: the two customer classes enter into energy service agreements (ESAs) for an initial term of at least ten years, as opposed to the typical term of one to five years; requirements to pay an exit fee equal to three years of minimum charges should the customer cancel the ESA after five years; collateral requirements tied to the customer's credit ratings; requirements to reduce demand on AEP Ohio's system during an emergency event; and requirements to participate in a separate energy procurement auction than standard offer service customers
[85] *Id*. at 7–8.
[86] AEP Ohio Proposed Tariff Modifications, Initial Comments of Data Center Coalition, at 9–12 (Jun. 25. 2024).
[87] *Basin Electric Power Cooperative*, 188 FERC ¶ 61,132 at PP 15–16, 61 (2024).
[88] *Id.* at P 95.
[89] *See* H.B. 2101, 2025 Gen. Assemb., Reg. Sess. (Va. 2025).
[90] *See* Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Andrew J. Williamson on Behalf of Indiana Michigan Power Company, at 5 (Jul. 19, 2024).
[91] *Id*. at 3, 6–7.
[92] *Id.* at 14.
[93] *Id.*; *id.* at 16 (tariff terms ensure data center provides "reasonable financial support for the significant transmission and generation infrastructure needed to serve large loads").
[94] Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Benjamin Inskeep on Behalf of Citizens Action Coalition of Indiana, Inc. [hereinafter Citizens Action Coalition of Indiana Testimony], at 25 (Oct. 15, 2024).
[95] *Id.* at 36.
[96] *Id.* at 24–31.
[97] Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Carolyn A. Berry on Behalf of Amazon Web Services, at 16 (Oct. 15, 2024).
[98] *Id.*
[99] *Id.*

[100] *See generally Application of Nevada Power Company to Implement Clean Transition Tariff Schedule*, Nevada Pub. Util. Comm'n Docket No. 24-05023 [Nevada Power Clean Transition Tariff], Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff (Jan. 16, 2025); Nevada Power Clean Transition Tariff, Direct Testimony of Jeremy I. Fisher on Behalf of Sierra Club, Docket No. PUCN 24-05023, at 10–20 (Jan. 16, 2025).
[101] *See generally* Nevada Power Clean Transition Tariff, Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff, at 7–8 (Jan. 16, 2025).
[102] Nevada Power Clean Transition Tariff, Stipulation (Feb. 7, 2025).
[103] *See, e.g.,* GA. CODE ANN. § 46-3-8 (allowing utilities to compete to provide service to certain new customers demanding at least 900 kilowatts).
[104] *See* Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Citizens Action Coalition of Indiana Testimony, at 11 (Oct. 15, 2024) ("Using I&M witness Williamson's example portfolio that has an average resource cost of $2,000/kW and has an average accredited capacity of 50%, I&M will also need to make $17.6 billion in new generation investments to serve 4.4 GW of new hyperscaler load.").
[105] ERIC GIMON, MARK AHLSTROM & MIKE O'BOYLE, ENERGY PARKS: A NEW STRATEGY TO MEET RISING ELECTRICITY DEMAND 7 (Energy Innovation Policy & Technology, Dec. 2024).
[106] *Id*. at 8.
[107] *See id.* at 19.
[108] *See id.* at 8–21.
[109] *See, e.g.,* State ex rel. Utilities Commission v. North Carolina Waste Awareness and Reduction Network, 805 S.E.2d 712 (N.C. Ct. App. 2017), *aff'd per curiam*, 371 N.C. 109, 617 (2018).
[110] See Sawnee Electric Membership Corporation v. Public Service Comm'n, 371 Ga. App. 267, 270 (2024) (". . . [T]he text of the Act assigns each geographic area to an electric supplier but also includes the large load exception to allow customers to choose their electric supplier if certain conditions exist . . . the premises must be 'utilized by one consumer and have single-metered service").
[111] *See generally* David Roberts, *Assembling Diverse Resources Into Super-Powered "Energy Parks:" A Conversation with Eric Gimon of Energy Innovation*, VOLTS (Jan. 15, 2025) (featuring an Energy Innovation author describing energy parks in rural cooperative territory in Texas).
[112] *See, e.g.,* Paoli Mun. Light Dept. v. Orange County Rural Elec. Membership Corp., 904 N.E.2d 1280 (Ind. Ct. App. 2009) (ruling in favor of a cooperative utility that sued to prevent a municipal utility from providing electric service to a facility owned by that municipality but located within the cooperative's service territory).
[113] *See, e.g.,* Power for Tomorrow (last visited Jan. 29, 2025), which claims to be "the nation's leading resource" about the "regulated electric utility model" and generally opposes competition with utilities, in part by claiming that competition harms residential consumers. The effort is funded by utilities. *See* Energy and Policy Institute, *Power for Tomorrow* (last visited Jan. 29, 2025).
[114] AEP Ohio Proposed Tariff Modifications, Testimony of Paul Sotkiewicz on Behalf of the Retail Energy Supply Association, at 9–10 (Aug. 29, 2024).
[115] *Id.* at 15.
[116] *Id.* at 14–15.
[117] The trade group's analyst observed that in January 2023 AEP projected only 248 megawatts of data center growth through 2038, but one year later AEP projected 3,700 megawatts of data center growth by 2030. *Id.* at 10 (citing PJM reports).
[118] TYLER NORRIS ET AL., RETHINKING LOAD GROWTH: ASSESSING THE POTENTIAL FOR INTEGRATION OF LARGE FLEXIBLE LOADS IN U.S. POWER SYSTEMS 18 (Nicholas Institute for Energy, Environment & Sustainability, 2025).
[119] *Id*. at 5–6.
[120] See Ari Peskoe, *Replacing the Utility Transmission Syndicate's Control*, 44 ENERGY L. J. 547 (2023).
[121] Exec. Order No. 14,141, 90 FR 5469 (2025).
[122] *Id*.
[123] Va. J. Legis. Audit & Rev. Commission 2024-548, Report to the Governor & the General Assembly of Virginia: Data Centers in Virginia, at viii (2024).
[124] Brody Ford & Matt Day, *Price Tag Jumps for Amazon's Mississippi Data Centers Jump 60% to $16 Billion*, BLOOMBERG (Jan. 31, 2025).
[125] *Id.*
[126] *See generally* NATHAN SHREVE, ZACHARY ZIMMERMAN & ROB GRAMLICH, FEWER NEW MILES: THE US TRANSMISSION GRID IN THE 2020S, GRID STRATEGIES (Jul. 2024).
[127] U.S. Department of Energy, *National Transmission Needs Study* (Oct. 30, 2023).
[128] See Ari Peskoe, *Replacing the Utility Transmission Syndicate's Control*, 44 ENERGY L. J. 547 (2023)

[129] Sonali Razdan, Jennifer Downing & Louise White, *Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update*, U.S. Department of Energy Loan Programs Office (Jan. 2025).
[130] *See, e.g,* Mississippi Power Company's Notice of IRP Cycle, Mississippi Public Service Comm'n Docket No. 2019-UA-231 (Jan. 9, 2025) (stating that because the utility has entered into two contracts with 600 MW of new load it will keep at least one coal plant open that had been slated for retirement); Mississippi Power Special Contract Filing, Mississippi Public Service Comm'n Docket No. 2025-UN-3 (Jan. 9, 2025) (showing that at least one of the two special contracts is with a data center).



Load Growth Is Here to Stay, but Are Data Centers?

Strategically Managing the Challenges and Opportunities of Load Growth

July 2024

Energy+Environmental Economics

This whitepaper is prepared by:

Isabelle Riu, Senior Managing Consultant

Dieter Smiley, Senior Consultant

Stephen Bessasparis, Associate

Kushal Patel, Senior Partner

Recommended Citation:

I. Riu, D. Smiley, S. Bessasparis, K. Patel, "Load Growth Is Here to Stay, but Are Data Centers?: Strategically Managing the Challenges and Opportunities of Load Growth," Energy and Environmental Economics, Inc., July 2024. Available at: https://www.ethree.com/

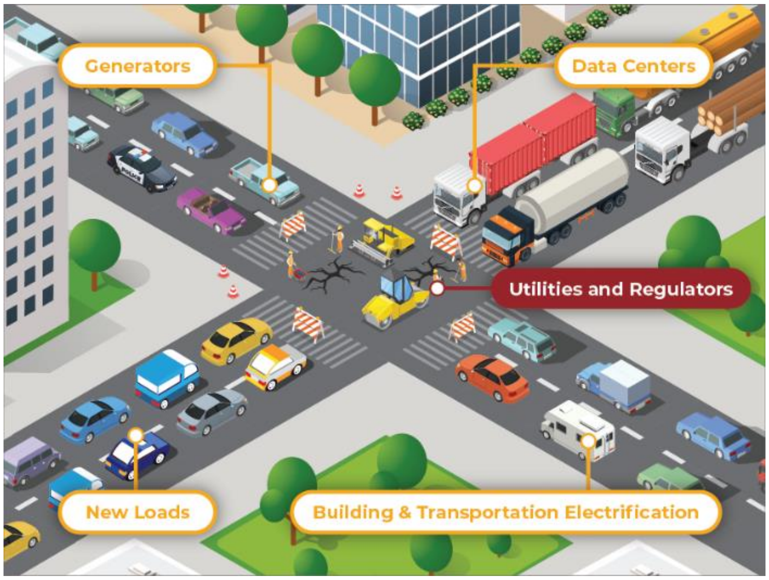
Until recently, the focus of the energy transition has primarily been on retiring legacy fossil generators and adding more renewables and energy storage that can sustain electrification-driven load growth in the longer-term. Now, rapid near-term load growth is underway, driven by large loads like data centers for artificial intelligence (AI) as well as a resurgence of U.S. industry due to industrial policy and manufacturing reshoring. This surge has surprised utilities and regulators across the country as they steer an aging grid through the challenges of an already ambitious energy transition. While the suddenness of these new large loads may seem unexpected, careful analysis highlights strategies to understand and mitigate risks as well as taking advantage of the opportunities they may enable.

Data center demand growth poses three primary challenges:

- Data centers are highly incentivized to interconnect as quickly as possible but face significant congestion and delays.
- Large new point loads can require substantial grid upgrades, forcing utilities to make potentially risky decisions about allocating scarce capital and managing ratepayer impacts.
- Data centers may consume large quantities of energy (both from existing and new electricity generators), which may challenge grid reliability if unmanaged.

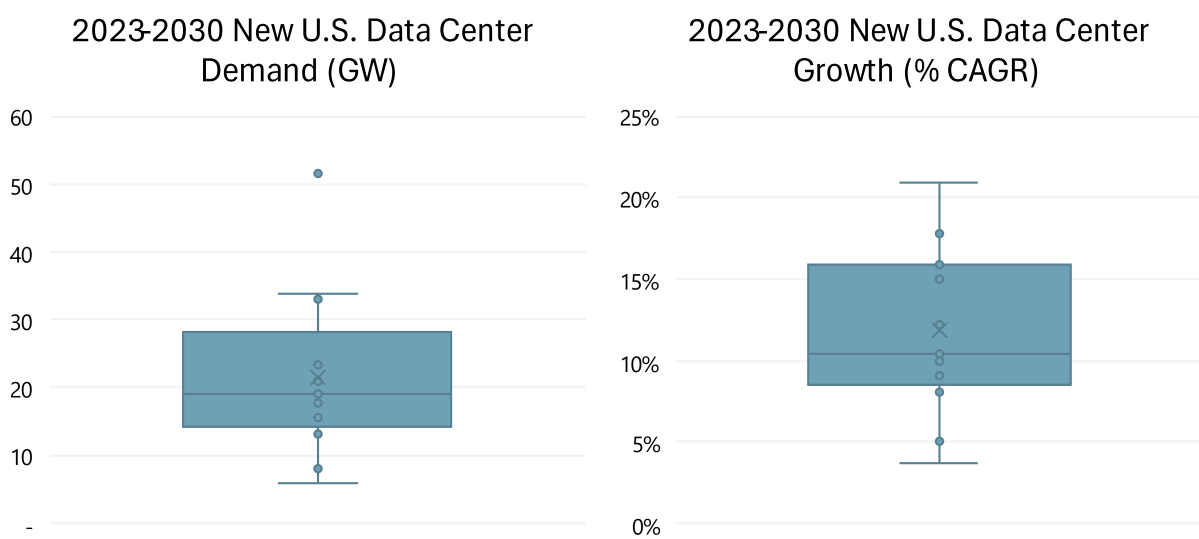
If the transforming grid is a traffic jam during highway construction, then data centers are a large convoy of trucks with urgent deliveries pulling into the on-ramp. This confluence of factors creates a gridlock, where utilities and regulators are overwhelmed working to modernize and decarbonize the grid, while managing queues of generators and new loads seeking interconnection, all bottlenecked at the same constraint. This may lead to suboptimal outcomes if grid decision makers only see limited near-term options such as delaying new large loads interconnections and/or delaying retirement of existing fossil fuel generators.

Figure ES-1: "Gridlock"



In this context, data center demand forecasts may be over-estimated, or "hyped." If this is the case, it would likely be from limits to interconnect the demand, not the volume of near-term demand itself. AI is the much publicized and discussed cause of recent data center growth, given the level of large investments being made by several technology companies. As can be seen in Figure ES-2, many data center demand forecasts reflect large growth over the next several years albeit over a wide range. This range reflects several uncertainties such the fundamental demand for more computing power (or "compute") as well as supply of data centers which can be constrained by available power.

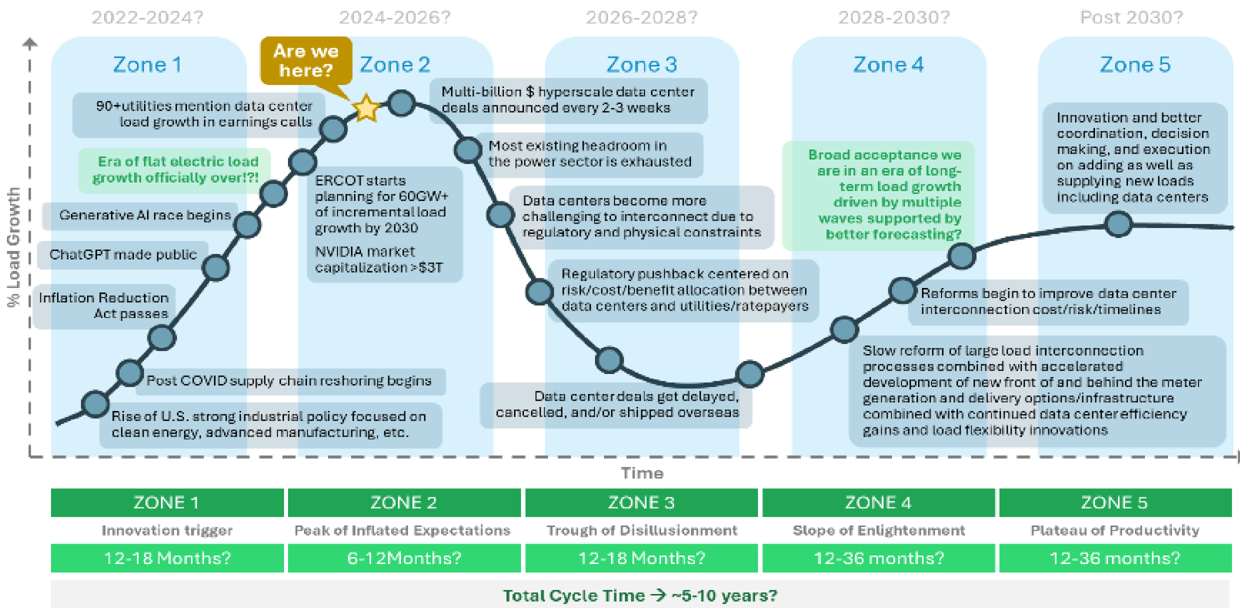
Figure ES-2: Range of Select Projections for U.S. Data Center Growth[1]



Even if the promise of AI falls short, general computing load is still likely to grow, due to factors like population growth and demographic shifts to more tech savvy generations, along with increased digitization of the economy. Figure ES-3 shows one way data center demand may change and evolve assuming we are currently near the top of a "hype" cycle.

[1] Projections from JLL, McKinsey, EPRI, IEA, BCG, Mordor and Goldman Sachs (total n = 13). E3 estimates data center capacity from energy estimates using an assumed 86% data center load factor and, as needed, linearly extrapolates projections to estimate changes from 2023 to 2030. BCG's "US Data Center Power Outlook" report issued in July 2024 provides its more updated view, projecting new data center demand growth ranging from 60 to 90 GW in 2023-2030. More detail provided in Appendix 1.

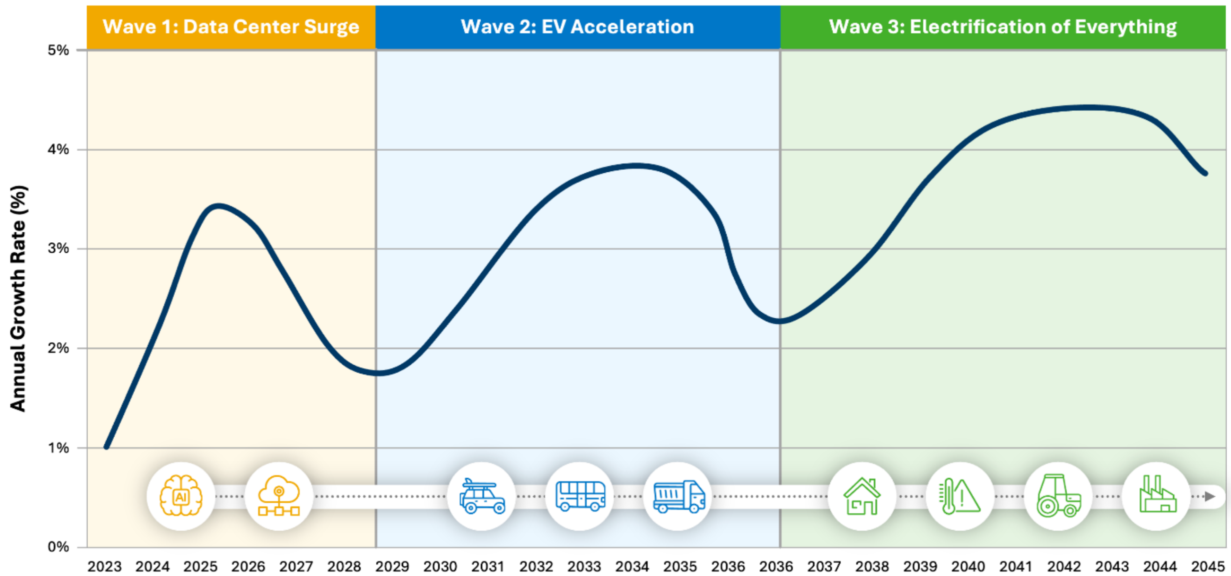
Figure ES-3: Are we in a Power Sector Data Center Hype Cycle? Illustrative Visualization based on Gartner Hype Cycle[2]



And if the near-term AI-driven load growth does flatten or even reverse, this is likely only the first wave of major U.S. load growth; the energy sector should prepare itself for the subsequent waves driven by strong industrial policies and electrification of transportation, buildings, and industry as seen in Figure ES-4. This is not the first time the U.S. power system has experienced this magnitude of demand growth, and we can learn from the past to make proactive decisions. A near-term rush of data center buildout and aggressive longer-term demand forecasts can put pressure on energy affordability and decarbonization efforts if not managed proactively. Establishing priorities is critical, and it will require all stakeholders to collaborate on demand- and supply-side solutions to avoid near-term unintended consequences and optimally capture long-term benefits. While data center load forecasts are inherently uncertain, uncertainty is no reason for paralysis nor a reason to avoid making proactive decisions.

[2] "Gartner Hype Cycle" Wikipedia.com. Accessed 21 June 2024. https://en.wikipedia.org/wiki/Gartner_hype_cycle

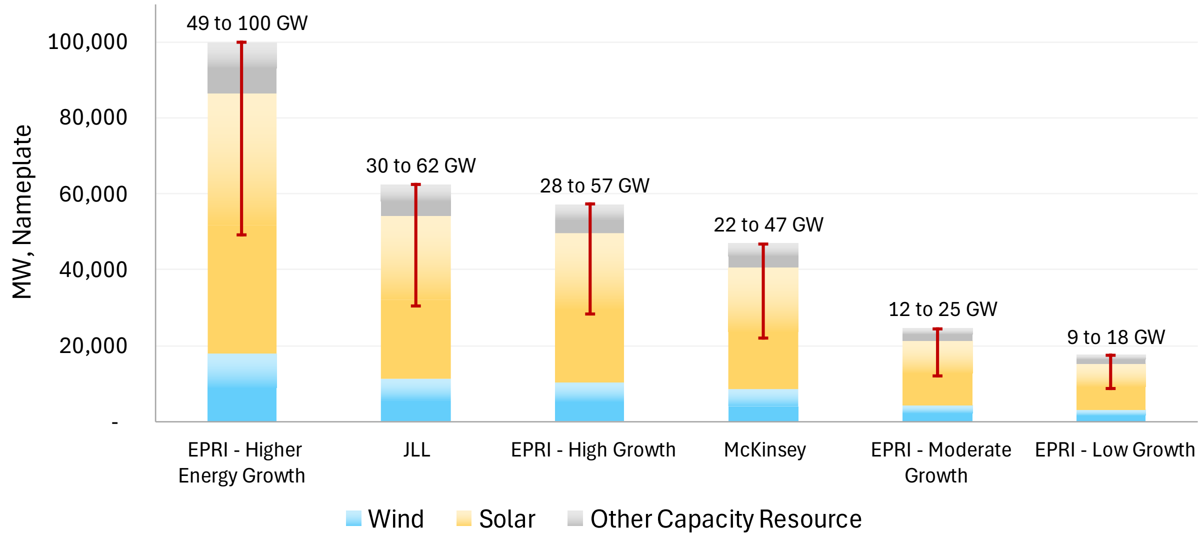
Figure ES-4: Waves of Load Growth (Illustrative Load Growth)



This paper seeks to ground the conversation around large load growth in some basic facts, offer historical context, and propose innovative ideas for large load developers, power industry planners, and investors to mitigate risks and take advantage of potential opportunities. We believe the decades-long work E3 has been doing on future load growth in the context of the energy transition, combined with a number of active engagements across our diverse client base, ranging from public sector regulators and agencies to utilities as well as private investors and developers, gives us a 360-degree understanding of the challenges, issues, and potential solution to help unjam the current gridlock between electric supply and demand.

There is still much uncertainty regarding the scope and scale of data center growth, but the key question should not be “How much will load grow?”, but instead, “Where and what kind of load growth can be accommodated?”. As we enter a “new build” era with multiple waves of load growth, planners must innovate and scale both demand and supply to navigate this evolving landscape effectively. Figure ES-5 shows initial, high-level E3 estimates on the level of new generation resources needed to meet the energy and grid reliability needs of data center demand, which can range from 20 GW to 100 GW of incremental new generation by 2030, reflecting the large uncertainty with demand and supply. It also includes error bars to indicate how uncertainty around potential energy efficiency improvements could impact builds, further emphasizing the need for adaptable resource planning.

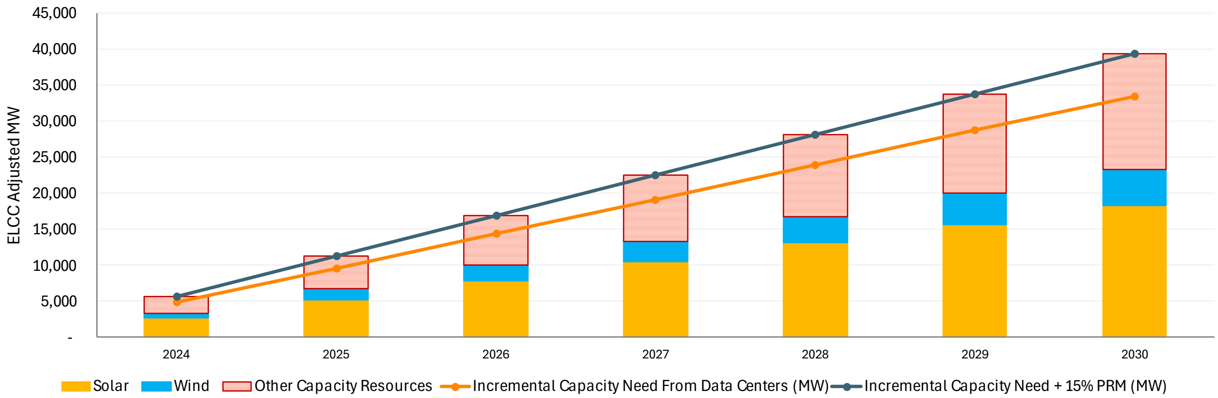
Figure ES-5: 2030 Resource Capacity with 75% Renewables to Meet Data Center Energy Demand with Varying Efficiency Improvements[3]



Electric grid planners and operators will need to ensure data center electricity needs are met reliably especially given many data centers need power supply at higher reliability standards than typical utility criteria, which means capacity resources will be required on top of resources that provide energy under average conditions to maintain service under peak (i.e. highest-need) conditions. Figure ES-6 illustrates E3's high-level analysis of what that need could be. We estimate that anywhere from 5 to 15 GW of additional capacity resources will be needed on top of assumed new renewables for reliability. These "other capacity" resources can take the form of currently commercial energy storage technologies, like lithium-ion batteries or pumped storage hydropower along with new peaking gas generation and customer demand response, as well as emerging technologies, such as long duration energy storage, low carbon fuels (such as hydrogen or renewable natural gas), enhanced geothermal systems, small modular nuclear reactors, and potentially others over time. Note that this analysis is for illustrative purposes using relatively simple heuristics and Appendix 1 provides additional detail on methodology.

[3] Uses EPRI Higher Energy Growth Scenario from "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf.

Figure ES-6: Effective Capacity Contribution of Renewables and Other Capacity Resources to Meet Incremental Data Center Peak Demands



Planning for load under uncertainty is nothing new, but the scale and speed of this load growth, combined with today's supply side constraints, is unprecedented. These unique circumstances require a new paradigm to avoid near-term unintended consequences and optimally capture long-term benefits. For example, data center load growth could be a positive for the industry if leveraged effectively. Well-resourced large baseload customers can help fund much-needed grid upgrades, support the adoption of emerging technologies, and drive new clean energy supply, potentially reducing costs for other customers and the system as a whole. For utilities and regulators, shifting away from traditional planning approaches to an integrated systems planning model would optimize existing resources, improve energy affordability, and support decarbonization efforts, all while enabling long-term strategic planning.

For more detailed information on proactive options and potential solutions see the "Options by Stakeholder" section of this paper. We provide a detailed set of options and their associated impacts on costs and risks, but this list is non-exhaustive. We expect each region in the U.S. to chart its own unique path in how best to manage near and longer-term load growth tailored to the local market structure and historical context. For example, large power users can manage energy needs through utility supply, self-generation, demand response, direct negotiation with generators, and infrastructure acquisition, while utilities and regulators can improve proactive planning, streamline interconnection, and implement cost-sharing and risk mitigation mechanisms to ensure grid reliability and affordability.

Key Takeaway: Load growth is likely here to stay, even if the exact nature, timing, and scale is unclear. This means that utilities, regulators, and customers – both large and small – should proactively work together to realize the potential benefits and avoid the hazards of this new paradigm.

<u>About Us:</u>

E3 works on hundreds of projects a year exclusively in the energy sector for a diverse range of clients, ranging from public sector regulators and agencies, to utilities, to private investors and developers. We believe this broad work gives us a unique perspective on the challenges, issues, and potential solutions needed to address rapid load growth.

We have already incorporated data center impacts into E3's custom North American–wide PLEXOS market model to support investors, developers, utilities, and system operators. E3 has been working with a variety of clients on data center related issues such as supporting utilities on load forecasting, rate design, load interconnection process improvement, and resource planning related to data center growth. For big technology companies, data center companies, and various investors, E3 has advised and built in-house models to support both the siting and interconnecting data centers, procuring clean energy, and assessing power supply options including demand response.

For more insights into how E3 can support stakeholders across the industry on the impacts and opportunities presented by new large loads, email Kushal.Patel@ethree.com.

The rest of this paper is organized into the following sections:

- Historical Context
- Scale and Shape of Demand
- Supply Challenges
- Options by Stakeholder
- Conclusion
- Appendix

Load growth over the past ten years in the United States has been relatively flat, with a national peak power demand growth of only 0.5% annually.[4] However, in 2023 peak power demand growth sharply increased to 0.9%, driven by data centers and other large new loads.[5] Data centers were estimated to account for 4% of total US electricity consumption in 2023 and are expected to continue to grow, possibly up to 9.1% by 2030.[6] Grid planners are adjusting their forecasts accordingly. They have nearly doubled the U.S. 5-year load growth forecast (from 2.6% to 4.7%), and many expect a peak demand growth of 38 GW through 2028.[7] This would require rapid planning and buildout of new generation and transmission and could threaten the planned retirements of fossil fuel power plants if not executed quickly enough.

This cycle is not without precedent, however. The post-WWII era saw rapid load growth as economic prosperity and the population both surged, homes electrified, and new industrial manufacturing facilities centers grew out of wartime production. The subsequent decades had largely flat load, although there were pockets of regional high load growth driven by local manufacturing and/or population growth, such as in the Sunbelt, offset by de-industrialization and population loss in other regions. We are now seeing a return to a rapid growth era with the development of new digital industries along with advanced manufacturing and supply chain reshoring.

However, the landscape for growth is much different today, both in terms of the sheer volume of load growth being contemplated in absolute terms and today's more challenging environment to build large new infrastructure from a cost, regulatory, and timing perspective. Figure 1 shows the electricity usage growth rate averaged over 5-year periods to illustrate this historical context; grid planners and utilities have rapidly built out infrastructure in response to steep load growth in the past and need to revive these capabilities again.

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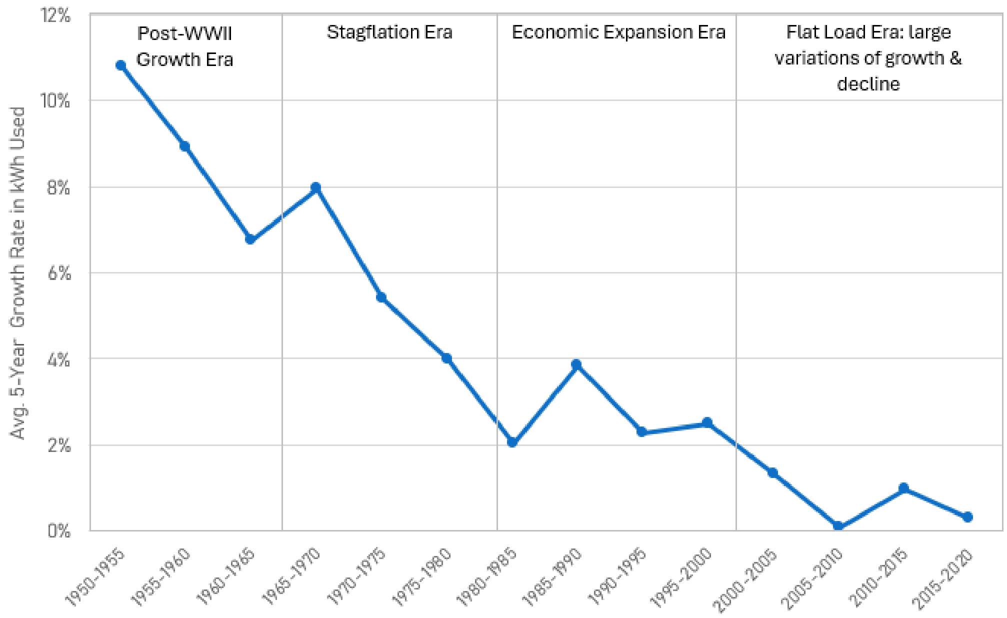
[4] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

[5] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

[6] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." Electric Power Research Institute. 2024. https://www.epri.com/research/products/3002028905

[7] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Figure 1: 5-Year Avg. Growth Rate in Electricity Usage 1950-2020[8]



The initial decades of digitally-driven load growth were not as large as initially anticipated due to efficiency gains and microchip development trends in line with Moore's Law, i.e. the observed doubling of transistors in an integrated circuit roughly every two years. Subsequently, the average power usage effectiveness[9], a measure of the inefficiency of transforming electrical energy into server processing time, in U.S. data centers decreased from an average of 2.5 in 2007 to about 1.5 in 2022. This has tempered a demand spike from data centers, i.e. more compute for less energy.

It is unclear if these trends will continue through the current phase of data center construction, but observers note that gains in data center efficiency have slowed in recent years.[10] This trend, combined with the unique demands of AI data centers, could lead to new demand significantly exceeding future efficiency gains and driving a stark increase in system-wide electrical load.

The potential scale of this new load is bound by the system's ability to supply power and the ability of demand to effectively use said power.

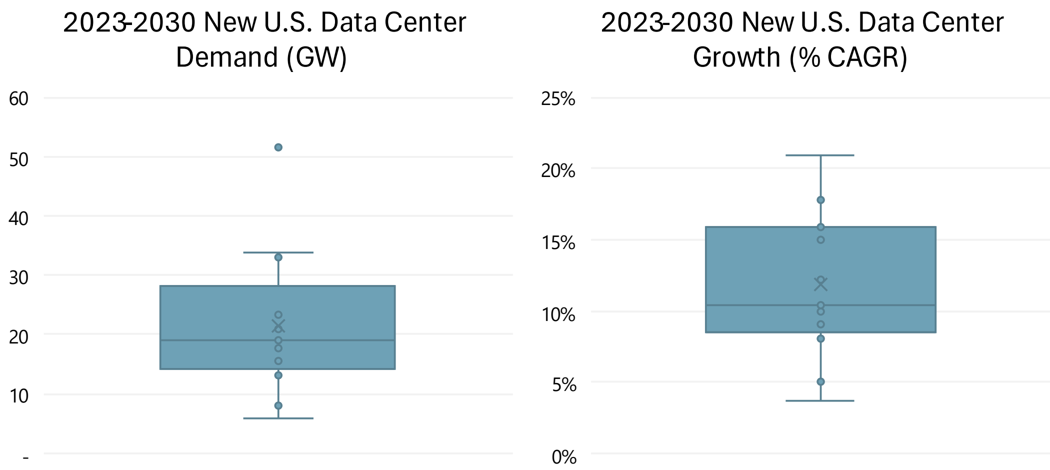
[8] "Monthly Energy Review." U.S. Energy Information Administration. May 2024. https://www.eia.gov/totalenergy/data/monthly/

[9] Power Usage Effectiveness (PUE) is a data center industry-preferred metric that represents the infrastructure energy efficiency for data centers. It divides the facility's total energy usage by the IT equipment's energy usage. A lower PUE indicates a more efficient data center using less energy to run secondary functions like cooling.

[10] Daniel Bizo. "Global PUEs – are they going anywhere?". 04 December 2023. https://journal.uptimeinstitute.com/global-pues-are-they-going-anywhere/

Estimates vary, but most agree the potential scale of data center demand is extremely large. Many observers forecast at least 15 GW to 30 GW of new data center demand will be added to the U.S. system by 2030, with a theoretical upper limit[11] of 70 GW based on worldwide microprocessor fabrication limitations.[12] The growth of AI is expected to be a major driver; AI has represented half of data center power demand growth since 2016, and this share is predicted to increase through 2030.[13]

Figure 2: Range of Select Projections for U.S. Data Center Growth[14]



AI energy demand can be categorized into the two major phases of an AI's lifetime: training and utilization (also known as inference).[15] During the training phase, the AI program is digesting vast amounts of data to build the associations needed for the model to work. This typically has consistently high power requirements. During the utilization phase, the completed model is responding to user queries and performing its actual task. The exact scale of this growth depends on several independent factors in the energy-to-AI value chain, which is a multi-step process of transforming energy into compute and ultimately into completed AI tasks with economic value. Forecasts are sensitive to changes in these factors, as a modification to a step in the process, such as an efficiency improvement, can have a significant impact on total energy demand.

[11] As NVIDIA's servers could be sold anywhere globally, the upper end of the forecast assumes the US has the lion's share of the growth.

[12] Alex de Vries. "The growing energy footprint of artificial intelligence." Cell: Joule. 10 October 2023. https://doi.org/10.1016/j.joule.2023.09.004A

[13] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

[14] Select projections from JLL, McKinsey, EPRI, IEA, BCG, Mordor and Goldman Sachs, including low, medium, and high scenarios (total n = 13). E3 estimates data center capacity from energy estimates or vice versa using an assumed 86% data center load factor and, where applicable, linearly extrapolates projections to estimate changes from 2023 to 2030. BCG's "US Data Center Power Outlook" report issued in July 2024 provides its more updated view, projecting new data center demand growth ranging from 60 to 90 GW 2023-2030. More detail provided in Appendix 1.

[15] Michael Copeland. "What's the Difference Between Deep Learning Training and Inference?". NVIDIA. 22 August 2016. https://blogs.nvidia.com/blog/difference-deep-learning-training-inference-ai/

The Impact of Energy Efficiency on Demand Growth

Each of the steps in the energy-to-AI value chain has an associated transformation efficiency, with both physical factors (e.g., power plant heat rate) and financial factors (e.g., the cost of acquiring new data center capacity) acting on those efficiencies. For example, an increase in microchip energy or cooling efficiency would enable more compute to be extracted from an energy input, decreasing the energy needed to run the same amount of AI capacity. Conversely, creating a new AI model that can accomplish new, high-value tasks (e.g., interpreting radiological scans in healthcare or mass consumer adoption of AI assistants) would incentivize greater production of AI capacity with associated increases in energy demand.

Toggling just the variable of efficiency improvements can have significant impacts on the total energy needed to meet this new AI-driven demand. Suppose NVIDIA's recently announced Grace CPU Superchip, which reportedly consumes 50% less power than other chips of its type, becomes the new standard for efficiency in transforming energy into compute.[16] If compute is roughly half of a data center's energy consumption, this breakthrough may reduce 20 GW of anticipated new demand down to 15 GW and obviate the need for potentially one-third of new solar additions based on E3 analysis. Figure 3 shows a wide range of potential data center load growth trajectories (normalized to today's data center demand levels) across several high-level scenarios focused on efficiency improvements.[17]

There could be a wide range of demand growth outcomes solely on the variable of efficiency improvements, with the low end still significant at 50% growth from today's level.

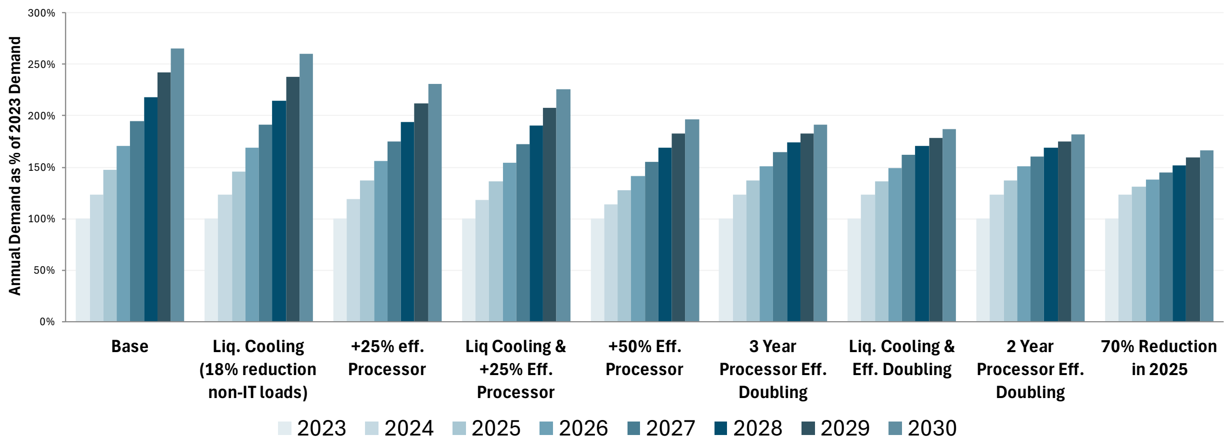
Figure 3: Illustrative Data Center Energy Demand Growth Under Efficiency Improvement Scenarios

Scenario	Description
No Assumed Efficiency	No incremental efficiency. Assumes energy demands consistent with EPRI's U.S.-wide Higher Energy Growth projections (cumulative 250 TWh of new energy demand by 2030) and power usage effectiveness (PUE) of 1.2
Liquid Cooling (10% Reduction)	Liquid Cooling, rather than air cooling, is assumed to result in 10% facility wide energy reductions. Applied to all years
+25% Efficiency Processor Improvement	25% improved efficiency is assumed for processing power. Applied to all years

[16] Ivan Goldwasser. "Green Light: NVIDIA Grace CPU Paves Fast Lane to Energy-Efficient Computing for Every Data Center." NVIDIA. 21 March 2023. https://blogs.nvidia.com/blog/grace-cpu-energy-efficiency/https://blogs.nvidia.com/blog/grace-cpu-energy-efficiency/

[17] E3 modeled incremental efficiency gains on top of the projected energy amounts. As a result, any energy efficiency measures that may have already been included in the source material were not taken into account.

Liquid Cooling and +25% Efficiency Processor Improvement	25% improved efficiency is assumed for processing power and subsequent 10% efficiency gain is applied facility wide. Applied to all years
+50% Efficiency Processor Improvement	50% improved efficiency is assumed for processing power. Applied to all years
3 Year Processor Efficiency Doubling	Processor efficiency is assumed to double every 3 years (first improvement in 2025)
Liquid Cooling and Efficiency Doubling	Processor efficiency is assumed to double every 3 years (first improvement in 2025) and subsequent 10% efficiency gain is applied facility-wide
2 Year Processor Efficiency Doubling	Processor efficiency is assumed to double every 2 years (first improvement in 2025)
70% Reduction in 2025	Facility wide energy reductions of 70% assumed beginning in 2025

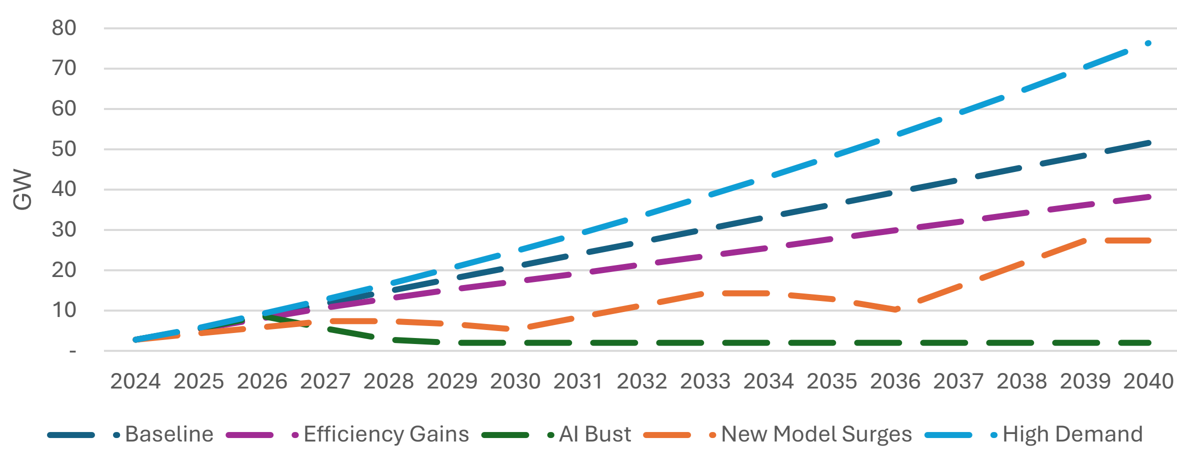


The Impact of the AI Use Case on Demand Growth

This framing also illustrates the main incentive behind AI data center load growth: the value of the tasks AI can accomplish. In an efficient market, the cost of acquiring the fuel, energy, compute, and AI capacity to create an AI model should not exceed the value of the tasks it can accomplish. Theoretically, this limits the amount of energy to be dedicated to the AI. For example, consider the value of interpreting radiological scans. There are approximately 32,000 radiologists in the U.S. with a mean annual wage of $354,000. If AI replaced 10% of the value of their labor, then that AI would have a value of about $1.1 billion. The cost of the supporting inputs, including the infrastructure needed to produce and deliver the electrical energy, would be significantly less than this for the creation of that AI to make economic sense. Conversely, if AI demand flatlines or even declines due to fundamental challenges with the technology, such as a barrier to further AI model development, then flatline or declining growth could occur, especially if the near-term demand represents a "boom" or overinvestment cycle to “win” the AI race. Estimating the value of AI tasks and the costs of each step of the conversion process can provide a fundamentals-based estimate for the amount of energy dedicated to AI.

These different factors informing how AI is used in society could play out in a range of different growth trajectories as illustrated in Figure 4. For example, if there are high demand drivers consistent with discovering more profitable uses for AI, we would expect data center load growth to increase over time. In contrast, if market saturation decreases demand, marginal inputs become prohibitively expensive, or the load becomes increasingly flexible (by moving computing loads in time and/or utilizing data center on-site generation), we would expect load growth to slow over time. If a significant portion of load comes from the training phase of AI model development and new models are trained on a periodic basis, then we would expect periodic surges in demand to train new energy-intensive models followed by relative troughs as those models are utilized by consumers. Finally, if AI turns out to not have very many market applications and stops improving, then we would expect the load growth from AI data centers to drop back down to pre-2023 baselines. In short, there is a wide range of potential load growth shapes hinging on how AI evolves and is used, creating a large cone of uncertainty and it is important to consider these factors when developing data center load forecasts.

Figure 4: Projected AI Load Growth Under Various AI Growth Scenarios

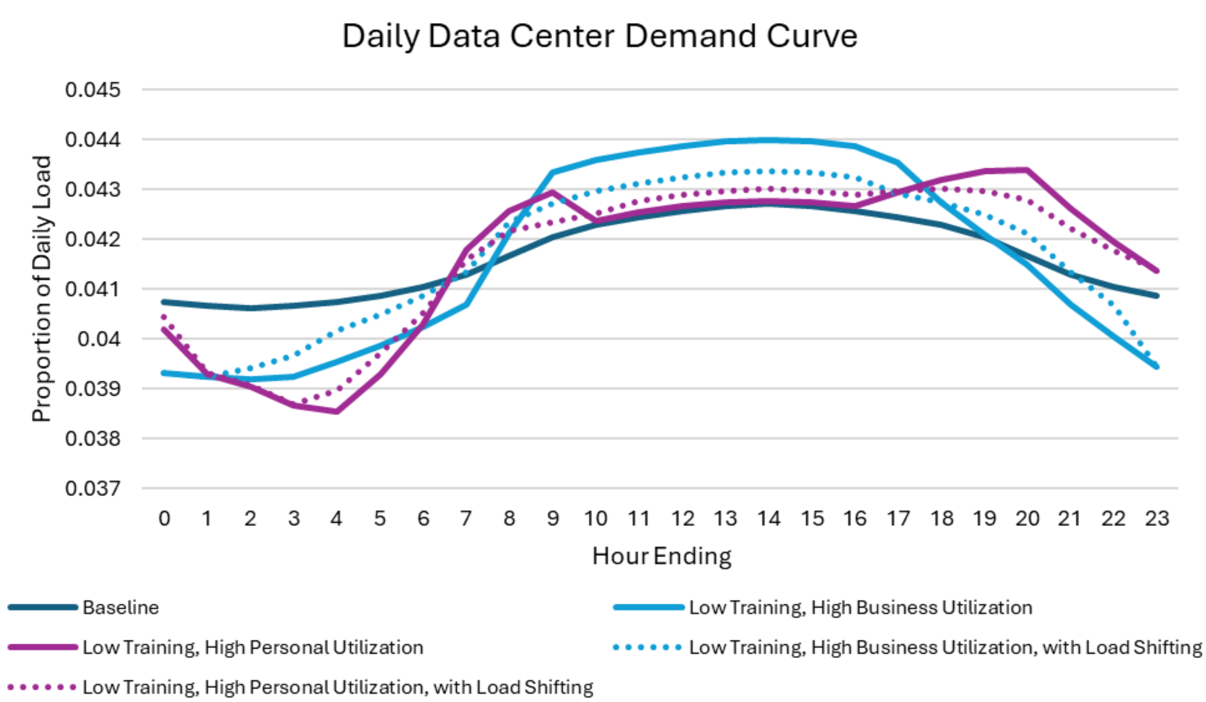


The Role of AI’s Daily Use Case on Demand Growth

The use case and level of demand for AI may also affect the shape of the daily data center load curve. Data centers are capital intensive, from building sites to buying servers, which incentivizes the facilities to run at high utilization, which is also aligned to the underlying business need. Currently, data centers, which are high load factor i.e. mostly baseload facilities, have a relatively flat shape, reflecting baseload computing needs, but also have some seasonal variation due to significant weather-dependent cooling needs. This load shape could continue if new AI models are in constant development and therefore the majority of AI data center load is dedicated to model training.

However, if usage overtakes training as the dominant load source, then the daily peak would be more dependent on usage time and type. If AI is primarily a business tool, then peak demand may mostly coincide with business hours. If AI is mostly a personal tool, then twin morning and evening peaks may be more likely, resembling today's residential load shapes. Figure 5 illustrates these possible load shapes. There may be additional possible load shapes that reflect having more flexibility around AI computing, such as batching AI queries and running them flexibly during the day, moving other computing loads optimized around variables such as clean energy availability, and utilizing on-site behind-the-meter generation. Similar to the overall load growth trajectories to 2040, there is substantial uncertainty around future load shape, but it is unlikely to be truly flat, which has significant ramifications for grid planners and system operators on how to serve this demand.

Figure 5: Projected AI Daily Load Curve Under Various Usage Scenarios



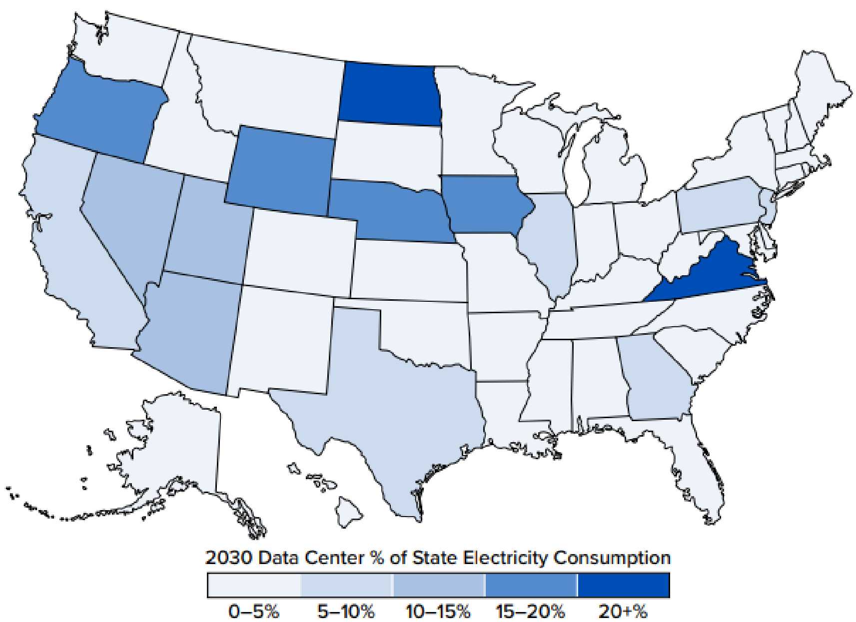
Geographically, this demand is and will likely continue to be highly uneven. In 2023, 80% of national data center load was concentrated in 15 states which can lead to localized grid stress.[18] These clusters occur because developers are attracted to areas that have large population centers, strong internet connections, low electricity and land costs, potentially strong economic development policy incentives, skilled labor forces, and/or low disaster risk. But if primary markets saturate, development prices increase, and local community pushback grows, then new builds may transfer to other markets. These new markets may eventually see a significant proportion of their electricity

[18] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

generation consumed by data centers, especially if the markets already had relatively low electricity consumption levels.

Data centers tend to operate in discrete geographic markets; the eight primary markets contain five times the data center volume as the eight secondary markets, and the top market, Northern Virginia, contains half of all primary market data center capacity.[19]

Figure 6: EPRI's Projected Data Center Share of Electricity Consumption in 2030[20]



[21]

In sum, data center demand is forecasted to be extremely large, but the exact scale, shape and geographic distribution of the growth are uncertain and depend on a number of variables. Planning for load under uncertainty is nothing new but the scale and speed of this new demand class combined with historic supply side constraints are unprecedented and have exacerbated the power system's gridlock.

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[19] "North America Data Center Trends H2 2023." 06 March 2024. CBRE. https://www.cbre.com/insights/reports/north-america-data-center-trends-h2-2023

[20] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

[21] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

While the U.S. generation system is robust, new data center load is growing during a time of major transition. E3 has developed high level analyses to illustrate how this new demand could be met amidst today's supply challenges by contextualizing the load against existing grid capacity and illustrating potential generation buildouts, reflecting historic thermal retirements, varying renewable energy goals, and reliability constraints. Appendix 1 provides additional detail on methodology but the purpose of these simplified calculations is to illustrate the potential scale of buildout needed and to underscore important planning considerations to serve this demand reliably and cleanly.

Utilizing Existing Grid Headroom

A key metric for the system's ability to absorb new load is the system's projected headroom. In this paper, headroom is defined as the difference between the grid's hypothetical generation potential and grid demand. It exists for a variety of reasons, but mostly reflects the margin needed to provide electricity at least cost while maintaining reliability.[22]

From a power perspective, the grid has a peaking headroom of approximately 100 GW. The 20 GW of new data center load alone would consume a significant portion of this headroom, but with baseline growth, the expected total additions of 38 GW lay an even heavier burden on the system.[23] This would occur during a time when firmer thermal generation is being retired in favor of cleaner, but more intermittent renewable generation. How exactly the headroom need is changing to reflect adding more intermittent renewables and batteries (which have lower reliability value compared to nameplate capacity) combined with lower levels of fossil fuel generators (which usually having higher reliability value compared to nameplate capacity) in the face of more extreme weather events is outside the scope of this paper but represents another important variable. Figure 7 and Figure 8 illustrate key scenarios, and additional sensitivities and details can be found in the appendix. Note that this analysis is for illustrative purposes using relatively simple heuristics based on E3 work to show potential impacts to headroom.

[22] Our calculations assume thermal fossil plants have an average forced outage rate of 10%, and therefore with sufficient demand could operate at 90% capacity factor.

[23] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

Figure 7: EIA Forecast Power Headroom by 2030 Under a Static 15% Planning Reserve Margin (PRM)

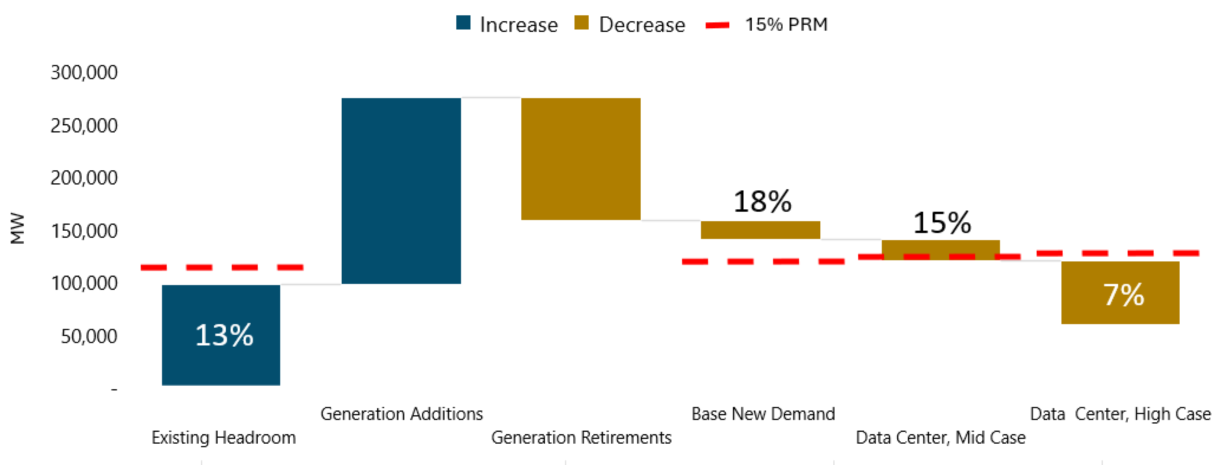
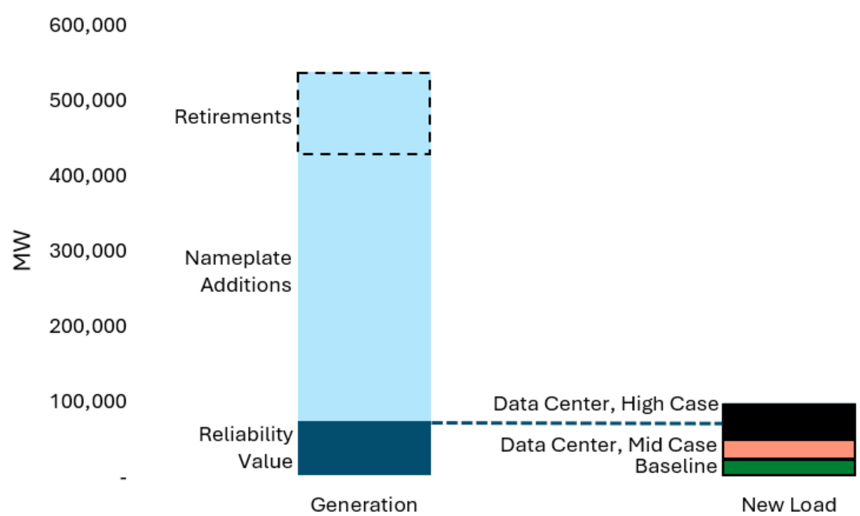


Figure 8: EIA Forecast Generator Additions and New Load by 2030



Planned additions will exceed planned load and increase overall headroom, but this is contingent upon sufficient system energy storage being able to shift intermittent renewable generation to peak times. Without long duration energy storage to enable a clean and reliable stream of power from these renewable additions and/or breakthroughs in clean firmer generation technologies (e.g., small modular nuclear reactors, advanced geothermal, and others), finding firmer and relatively cheap power for data centers that are reluctant to curtail operations during peak reliability periods may become complex. This increases the likelihood that data center load will need to be met with additional renewable generation with short-duration batteries. If this generation is not present, data centers may opt to build generation on-site or grid planners may need to delay fossil fuel generator retirements.

To meet this demand cleanly without reducing existing headroom, the system would need to add about 57 GW of solar and 15 GW of wind of nameplate capacity along with 10 GW of effective capacity from other technologies like energy storage or gas (this analysis uses basic calculations outlined in more detail in Appendix 1 and is meant for illustrative purposes). Meeting 75% of this energy demand with renewables would require 42 GW of solar and 11 GW of wind nameplate capacity with almost 14 GW of other effective capacity. While 61 GW of wind and 66 GW of solar were added to the grid in the past six years, thermal plant retirements exceeded thermal additions as aging fossil plants continue to shut down.

In 2023, 16 GW of capacity was retired from the grid – more than the lower estimate of data center load additions by 2030.

The overall conclusion is that headroom will likely be challenged by 2030, but there is a wide range of potential outcomes given 1) the uncertainty around future demand; 2) the uncertainty on the ability to keep pace with that demand with new generation additions that will predominantly be intermittent renewables and energy storage; and 3) the uncertainty around retiring existing generation (e.g. coal) as scheduled or even under an accelerated schedule.

Potential New Generation Buildouts

E3 performed analyses to illustrate the potential new resource builds required to meet incremental annual energy demands driven by data center development as informed by growth projections from Jones Lang Lasalle Incorporated (JLL),[24] McKinsey & Company (McKinsey),[25] and Electric Power Research Institute (EPRI).[26] Using simplified assumptions[27] to account for a mix of new renewable resources meeting 75% of incremental energy demands, E3 demonstrates that by 2030, required new builds could range from 20 GW to 100 GW of additional generation capacity, translating to 3 to 17 GW of new generator additions per year. Over the past six years, a record high deployment of renewables has been achieved, with an average of 21 GW of wind and solar being added annually. Our estimated range of required generators highlights the significant uncertainty in projected energy demand and the challenges of scaling supply to accommodate new data center growth, other load

[24] Kari Beets. "North America Data Center Report." JLL. 28 February 2024. https://www.us.jll.com/en/trends-and-insights/research/na-data-center-report

[25] Srini Bangalore, Arjita Bhan, Andrea Del Miglio, Pankaj Sachdeva, Vijay Sarma, Raman Sharma, and Bhargs Srivathsan. "Investing in the rising data center economy." McKinsey & Company. 17 January 2023. https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy

[26] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

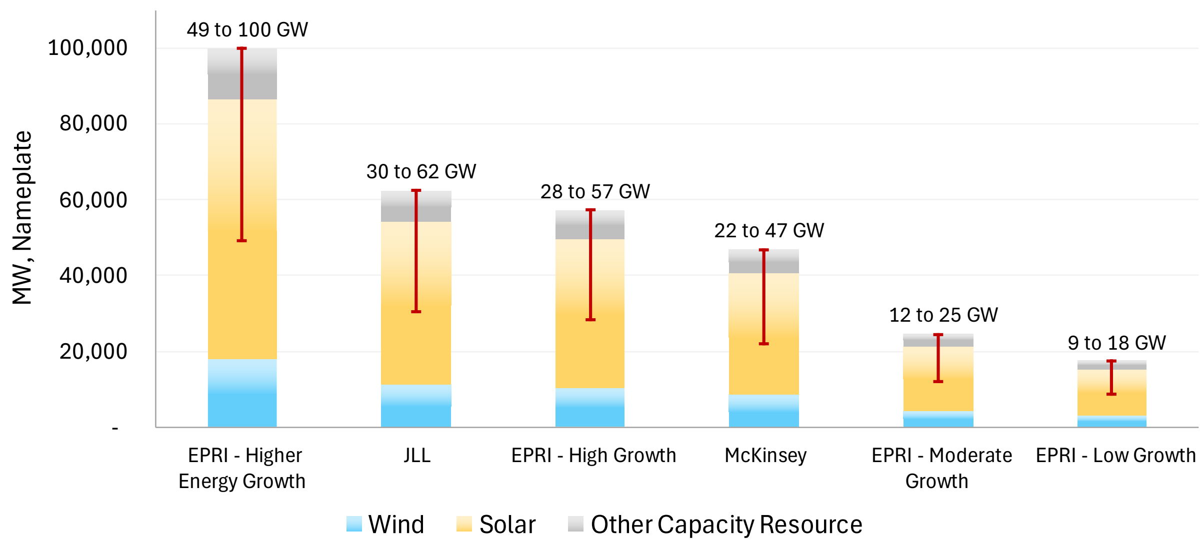
[27] New renewables generation is comprised of 70% solar and 30% wind, with respective capacity factors of 22% and 36%; generic gas generation assumes a 54% capacity factor. For public reports that provide data center projections in terms of capacity (MW), energy demand is estimated assuming consumption profiles have a load factor of approximately 86%. More information in Appendix.

growth and replacing retiring fossil fuel units. Note these illustrative estimates depicted in Figure 9 only consider balancing energy demands with the generation potential of new resource builds.

E3 estimated new resource builds under a range of sensitivities, examining lower energy demands from incremental energy efficiency gains to computing and cooling data center operations. Figure 9 shows errors bars to indicate the range of uncertainty based on E3's hypothetical energy efficiency scenarios outlined in Figure 3. The efficiency analysis indicates that significant advances in data center operations could result in a large range of builds, further emphasizing the need for adaptable resource planning.

The sensitivities applied are illustrative but exhibit the additional uncertainty in forecasting load requirements of data centers in a sector uniquely sensitive to hardware and software technology improvements as well as rapidly shifting business models and demand drivers vs. other more "traditional" industries.

Figure 9: 2030 Resource Capacity with 75% Renewables to Meet Data Center Energy Demand with Varying Efficiency Improvements[28]



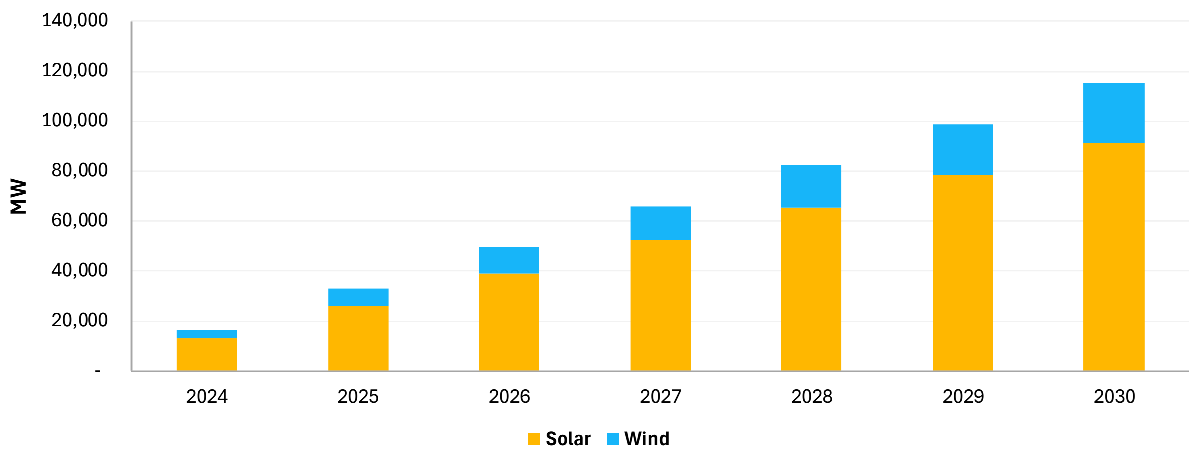
In addition to ensuring a sufficient annual energy supply, maintaining grid reliability at all times remains a crucial factor in grid operations as well as in resource and reliability planning. Addressing resource adequacy and reliability across various markets may necessitate different combinations of transmission, distribution, and generation builds and capacities, especially firmer resources, to meet projected growth in annual energy consumption and peak demand. A significant increase in

[28] Uses EPRI Higher Energy Growth Scenario

large high load factor demands, such as those from data centers, could further intensify build requirements, underscoring the need for proactive and comprehensive resource planning processes.

Building from the energy supply analysis above, E3 demonstrates the Effective Load Carrying Capability (ELCC)[29] (i.e. reliability or capacity value) of renewables needed to meet 100% of projected annual energy demands under EPRI's "Higher Energy Growth" scenario. This analysis highlights the potential magnitude and mix of resources required to maintain acceptable levels of reliability. To meet 100% of the incremental energy demand for data centers, 115 GW of nameplate renewables capacity would need to be built by 2030 as illustrated in Figure 10. However, to ensure reliable service, an additional 15 GW of additional firm capacity would still be necessary.

Figure 10: Renewables Nameplate Capacity to Meet 100% of Incremental Data Center Energy (EPRI - Higher Energy Growth)



Using static ELCC assumptions for solar and wind to estimate each technology's contribution to grid reliability, E3 estimated that the effective capacity contribution of renewables in 2030 would be nearly 23 GW, as shown in Figure 11. From EPRI's projected energy demands, E3 estimates the capacity needs of new data centers assuming an 86% load factor and a 15% planning reserve margin. The remaining 16 GW gap to meet estimated capacity requirements indicates the need to consider other capacity resources in planning efforts to maintain grid safety and reliability, whether that be energy storage, geothermal, nuclear, demand response, or thermal resource options.

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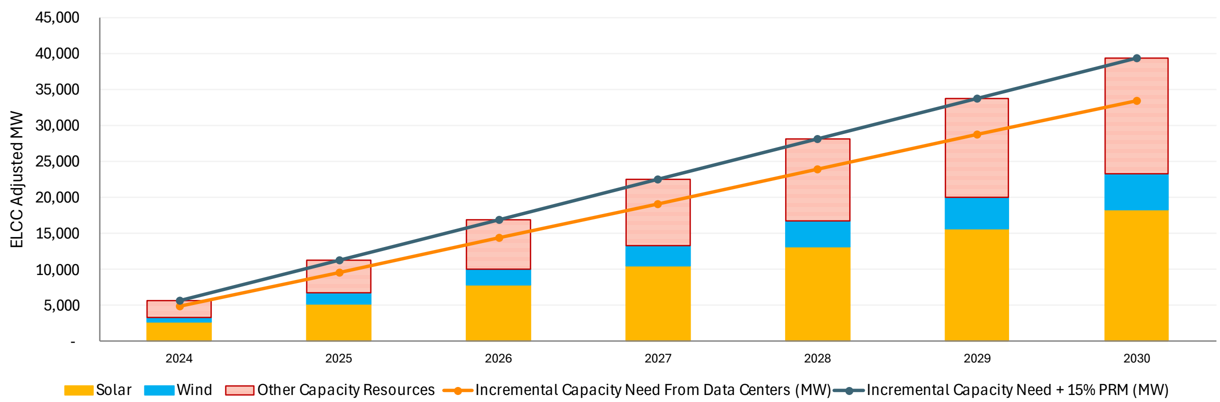
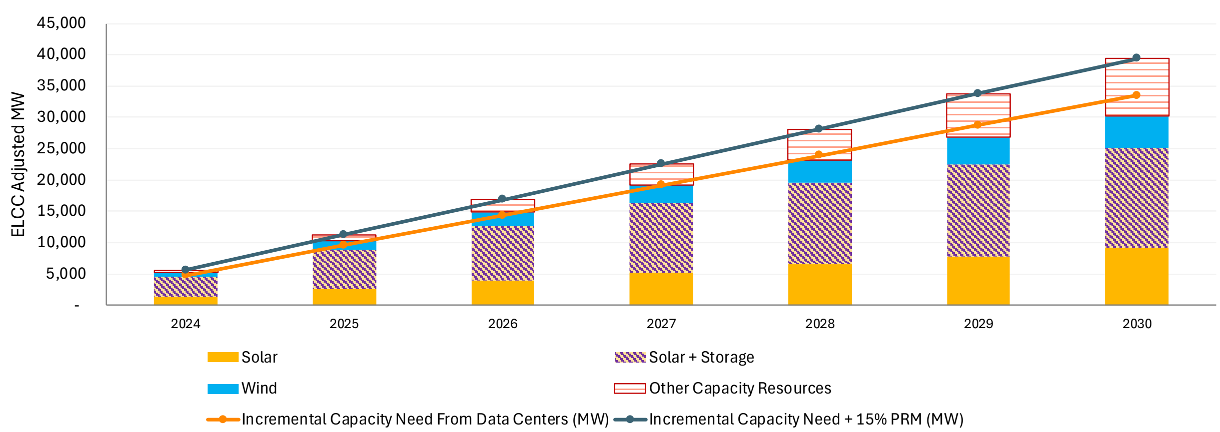
[29] See here for more information on ELCC: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf

Figure 11: Effective Capacity Contribution of Renewables and Other Capacity Resources to Meet Incremental Data Center Peak Demands



If half of the built solar nameplate capacity in Figure 11 is assumed to be paired with short duration storage,[30] renewables become much more effective in their reliability contributions, diminishing the need for incremental capacity resources. As illustrated in Figure 12, the effective capacity need from other capacity resource declines more than 40% from Figure 11 when half of the solar resources are assumed to be paired with short-duration storage.

Figure 12: Effective Capacity Contribution of Renewables with Storage and Other Capacity Resources to Meet Incremental Data Center Peak Demands.



Transmission and distribution infrastructure limitations may further complicate efforts to meet this new load. According to the Department of Energy's National Transmission Needs Study, a quintupling of transmission capacity is needed to meet a high load growth future by 2035.[31] But supply chain delays and multi-year planning processes continue to slow the deployment of new infrastructure, with transformer lead times increasing from 10 to 16 weeks pre-pandemic to 48 to 62

[30] Solar with storage is assumed to have an ELCC that declines linearly from 0.5 in 2024 to 0.35 in 2030.
[31] "National Transmission Needs Study." U.S. Department of Energy. October 2023. https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

weeks or more.[32] Generators waiting to come online to meet this demand are facing increasingly long interconnection timelines, growing from an average of 2.1 years in 2000-2010 to 3.7 years in 2011-2021; ultimately, 72% of projects withdraw.[33]

Critical to these supply challenges is the significant difference in development timelines between data centers and electric infrastructure. Data centers can be developed and connected in one to two years while new generation and transmission can take four years or more.[34] Given these long timelines to develop more supply, grid operators and utilities have postponed the retirement of fossil fuel power plants for reliability.[35] [36] These rollbacks clash with the customers' environmental goals and investments, and they threaten state and utility emission reduction targets. For example, delaying a coal plant retirement by just one year would have significant carbon emissions ramifications. A one-gigawatt coal plant with the average 42.1% capacity factor[37] and 2,300 lbs/MWh CO_2 emission rate[38] would emit 3.8 million metric tons of CO_2 in that year – equal to deploying nearly three gigawatts of utility-scale solar from an average avoided emissions perspective.[39] This example illustrates how any delay in coal retirements must be avoided from a carbon reduction perspective as it dwarfs most solar or wind additions.

Moreover, these operating challenges and large required investments pose major customer affordability, safety, and reliability concerns. While the rapid load growth from data centers is one cause of these challenges, strategically leveraging the resources of data center investors can also help derisk and finance many long-needed grid upgrades if there is an ability to appropriately balance costs, risk, and timing by all the stakeholders which is non-trivial.

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[32] Susan Partain. "Guessing Game; how Uncertainty in the Supply Chain is Affecting Utilities." American Public Power Association. 15 February 2023. https://www.publicpower.org/periodical/article/guessing-game-how-uncertainty-supply-chain-affecting-utilities

[33] Joseph Rand, Ryan Wiser, Will Gorman, Dev Millstein, Joachim Seel, Seongeun Jeong, Dana Robson. "Queued Up; Characteristics of Power Plants Seeking Transmission Interconnection." Lawrence Berkeley National Laboratory. April 2022. https://eta-publications.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf

[34] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

[35] Brand Plumer and Nadja Popovich. "A New Surge in Power Use Is Threatening U.S. Climate Goals." The New York Times. 14 March 2024. https://www.nytimes.com/interactive/2024/03/13/climate/electric-power-climate-change.html

[36] Nicole Jao. "US grid operator PJM asks Talen Energy to postpone fossil fuel plant retirements." Reuters. 11 January 2024. https://www.reuters.com/business/energy/us-grid-operator-pjm-asks-talen-energy-postpone-fossil-fuel-plant-retirements-2024-01-10/

[37] "Monthly Energy Review." U.S. Energy Information Administration. May 2024. https://www.eia.gov/totalenergy/data/monthly/

[38] "How much carbon dioxide is produced per kilowatthour of U.S. electricity generation?". U.S. Energy Information Administration. 07 December 2023. https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

[39] "AVERT v4.3 Avoided Emission Rates 2017-2023 (April 2024) xlsx." U.S. Environmental Protection Agency. https://www.epa.gov/avert/avoided-emission-rates-generated-avert

These unprecedented circumstances require a new paradigm—one that prioritizes proactive planning, collaborative partnerships, and innovative solutions. By embracing this approach, both power system planners and customers can navigate the challenges posed by large load growth while advancing towards a more sustainable, strategic, and reliable energy future. Listed below are avenues stakeholders can pursue in the face of these challenges and become critical parts of the solution.

What can large load customers do, besides taking a scattershot approach to development leading to potential abandonment of sites as they wait for interconnection?

Large load customers prioritize fast interconnections and relatively low-cost reliable electricity. If waiting in interconnection queues is unacceptable, these customers have several options to minimize their missed opportunities, risks, and revenue losses, and even become a grid asset.

+ Historically, data centers have been passive loads, drawing continuous power from the grid. They generally have backup diesel or natural gas generators to maintain uptime during grid outages but rarely use them as they are located in highly reliable areas. Other technologies can provide clean back up and serve as grid assets, such as on-side battery storage, and can help manage peak demand more sustainably and affordably while helping to integrate renewables. Viewing back up power as a strategic asset deployment could transform the industry from being a “sink” (inflexible flat load, demanding specific power level at specific time frame) to a partner or potential “source” in a sustainable future. In exchange for the project providing valuable grid services, utilities can more effectively and quickly enable access to power.
+ Data centers can commit to flexible load plans to accommodate grid limitations and avoid lengthy upgrade timelines. For example, facilities can leverage the temporal and spatial flexibility of certain AI workloads (e.g., model training) and schedule batch data processing to optimize power usage around renewable energy availability and total system load.
+ Collaborating directly with utilities and/or market operators (depending on the region) can drive innovative solutions. For example, coordinating during peak periods can position data centers as large-scale, flexible grid assets. While this might under-utilize rapidly depreciating high-cost servers, it may be a worthwhile trade-off if it enables a faster interconnection, which may have significant strategic business value to data centers, in addition to providing compensation for their flexibility and a reduced carbon footprint.[40] [41]

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[40] “Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption.” EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

[41] Data centers should also continue to work on in reducing overall energy footprint by investing in energy efficient computational hardware (which represents 40-50% of data center energy consumption) and cooling technology (30-40%). For example, a recent study examining a shift from 100% air cooling to 25% air and 75% liquid cooling observed a 15.5% decrease in the data center’s energy usage.

- Data centers can also leverage their relative flexibility in siting their loads, which is a new advantage as fossil fuel generation has historically been more geographically flexible than load.[42] While still considering proximity to fiber networks and low natural disaster risk, data centers are generally able to seek out areas with low-cost land, renewables, access to water, and sufficient grid capacity to meet their needs. Data center planners should expand their search areas beyond the traditional primary markets to take advantage of these new opportunities and could acquire existing infrastructure or support new transmission lines to minimize interconnection time.

Table 1 outlines options for large load customers along with some examples in action.

Table 1: Summary of Options for Large Load Customers

Option	Examples in action
Self-generate to bridge the gap until full service is available or use for flexibility (e.g., interruption or demand response)	Enchanted Rock has its "Bridge-to-Grid" offering, building microgrids for facilities awaiting firm grid connection. Once interconnected, the resource can provide flexible capacity back to the grid and serve as backup power.[43]
Leverage flexible load via batch processing, task shifting, demand response, interruptible service tariffs	Google can shift compute tasks based on clean energy availability[44] and participates in demand response.[45]
Work with energy suppliers directly to bypass/minimize interconnection timelines	Microsoft deal with Brookfield for 10.5 GW of renewables.[46]
Work with specific utilities on innovative solutions	Amazon, Google, Microsoft and Nucor signed MOUs with Duke Energy to develop "Accelerating Clean Energy" tariffs that would lower the costs of investing in clean energy technologies through early commitments, facilitate beneficial on-site generation and participation in load flexibility programs.[47] Arizona Public Service has an Extra High Load Factor rate for customers that can demonstrate 50% of its annual energy consumption within APS is carbon free.[48]

[42] It is easier for a planner to decide the location of a natural gas power plant than move an entire city as an extreme example. However, current renewable generation is more geographically constrained than data centers.

[43] "Enchanted Rock Bridge-to-Grid Solution Addresses Power Demand Growth from AI and Electrification." Enchanted Rock. 16 May 2024. https://enchantedrock.com/enchanted-rock-bridge-to-grid-solution-addresses-power-demand-growth-from-ai-and-electrification/

[44] Ross Koningstein. "We now do more computing where there's cleaner energy." Google: The Keyword. 18 May 2021. https://blog.google/outreach-initiatives/sustainability/carbon-aware-computing-location/

[45] Varun Mehra and Raiden Hasegawa. "Supporting power grids with demand response at Google data centers." Google: Cloud. 03 October 2023. https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption

[46] "Brookfield and Microsoft Collaborating to Deliver Over 10.5 GW of New Renewable Power Capacity Globally." Brookfield. 01 May 2024. https://bep.brookfield.com/press-releases/bep/brookfield-and-microsoft-collaborating-deliver-over-105-gw-new-renewable-power

[47] "Responding to growing demand, Duke Energy, Amazon, Google, Microsoft and Nucore execute agreements to accelerate clean energy options." Duke Energy: News Center. 29 May 2024. https://news.duke-energy.com/releases/responding-to-growing-demand-duke-energy-amazon-google-microsoft-and-nucor-execute-agreements-to-accelerate-clean-energy-options

[48] Arizona Public Service Company. Extra High Load Factor Rate Schedule. Accessed July 9, 2024, from https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Business-NonResidential-Plans/ExtraHighLoadFactor.ashx?la=en

Acquire infrastructure that already has interconnection (e.g., former industrial site, underperforming load)	Amazon buys nuclear-powered data center from Talen.[49] Skybox Datacenters converted a vacant Prologis-owned distribution center in IL into a 30 MW data center. QTS Realty Trust purchased 400 acres previously planned as a $1.5B logistic park in AZ.[50]
Support new transmission lines looking to interconnect low-cost renewables	None public yet; emerging as existing transmission/generation headroom becomes constrained

What can utilities, system planners, and regulators do?

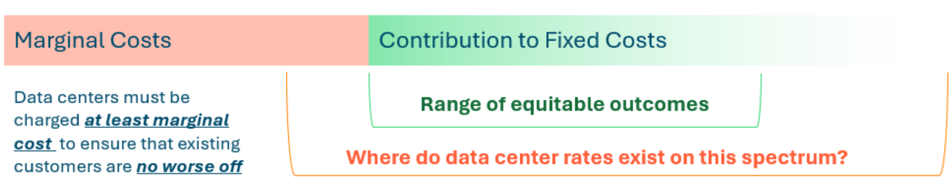
Given the scale of these projects and the relative novelty of these innovative opportunities, regulators need to develop the proper structure to appropriately value and compensate for these resources. More broadly, as these stakeholders think about proactive grid planning decisions, it is important to distinguish different categories of investments.

+ Growth-related investments that work to support near-term large loads, medium term electric vehicle growth, and longer-term building and industrial electrification
+ Investments with potential stranding and/or underutilization that may not benefit additional current and future customers, but ways to minimize risk
+ Investments that spread too much risk and/or cost to utility ratepayers that may not directly benefit from the investments

The options below can help maximize the value of the growth-related investments, suggest structures to minimize risk in utility investments, and manage potential ratepayer impacts. These options can have neutral to positive impacts on costs for other customers across utility rate classes as outlined in Figure 13. Accordingly, determining the appropriate level of investment to collect from large loads versus other customers will be key to ensuring an long-term equitable outcome.

Figure 13: Potential Spectrum of Utility Rates for New Data Center Customers

Cost Recovery Outcome	Description	Notes	Impact on Costs for Other Classes
Revenue < marginal costs	The utility does not fully recover marginal costs.	May be perceived as inequitable, as costs for other customer classes would increase but may be acceptable in the context of economic development.	↑
Revenue = marginal costs	The utility exactly recovers marginal costs.	May be perceived as equitable.	—
Revenue > marginal costs	The utility recovers marginal costs plus a fair allocation to non-marginal costs.	May be perceived as equitable.	↓
Revenue >> marginal costs	The utility recovers *more than* marginal costs plus a fair allocation to non-marginal costs.	May be perceived as an inequitable "overcollection" that benefits other customers at the expense of new data centers.	↓↓



[49] "Amazon buys nuclear-powered data center from Talen." Nuclear Newswire. 07 March 2024. https://www.ans.org/news/article-5842/amazon-buys-nuclearpowered-data-center-from-talen/

[50] Dan Rabb. "Industrial Sites Start Flipping to Data Centers Amid Fears Of Logistics Slowdown." Skybox Data Centers. 22 July 2022. https://www.skyboxdatacenters.com/news/industrial-sites-start-flipping-to-data-centers-amid-fears-of-logistics-slowdown

Table 2 below provides further detail on potential options and their cost and risk impacts.

Table 2: Summary of Options for Utilities, System Planners and Regulators

Goal	Option	Examples in action	Cost / Risk Impacts
Increase Proactive Planning	Identify and share data on where there is existing headroom and bring large loads into the long-term planning process.	California utilities: supported the combined IRP and transmission planning process, in which local network constraints are directly incorporated into the capacity expansion modeling framework	Identifying areas where investments to serve loads in the short-term would also support anticipated electrification in the long-term would yield savings.
Reform Interconnection Process from "First Come, First Serve" to Reduce Timeliness	Create a "fast track" by requiring upfront payment / long-term commitments to reduce timelines for credible (vs. speculative) loads.	Emerging	Collecting upfront payment would help the utility de-risk and improve cost-sharing.
	Allocate capacity via a competitive economic process e.g., auction or a "first ready, first serve" process.		Using an economic mechanism should increase efficiency and revenue.
Facilitate Large Loads Developing Own Resources and Leveraging Flexibility	Design tariffs that allow for flexibility and innovation on the load side such as on-site generation or being compensated for taking interruptible/non-firm service as well as promoting emerging generation technologies.	Duke Energy's proposed Accelerating Clean Energy tariffs would facilitate large customers' on-site generation, participation in load flexibility programs, and investments in clean energy.[51] NV Energy's Clean Energy Transition Tariff supporting large customers like Google's desire to adopt new clean energy technologies like enhanced geothermal.[52]	Flexible load management can provide cost savings to the utility and customer. De-risking as an early adopter emerging technologies for the clean energy transition like long duration energy storage, advanced nuclear, enhanced geothermal, carbon capture, and other technologies.
	Utilities could off-take or manage the unused energy or purchase in the future.	Omaha Public Power District to access 600 MW of wind capacity from NextEra's facility, which is part of Google's clean energy portfolio.[53]	Innovative procurement could help utilities meet regulatory requirements and ensure reliability more cost-effectively.
Implement Cost-Sharing Mechanisms to Avoid Inequitable Cost-Shift	Require large load customers to provide upfront investment or other risk mitigants such as long-term commitments.	AEP Ohio's proposed data center rate category would require 10-year contracts and a minimum demand charge payment based on 90% of contract capacity, up from 60%.[54] Duke Energy proposed a rate structure that would have a "minimum take" clause.[55]	Requiring upfront and/or additional investment could help fairly allocate risk and costs.
	Design large load tariffs based on incremental cost of service.	Emerging and there may already be examples from previous eras of growth.	Designing rates that more closely reflect cost structures would help minimize cost-shift.

[51] "Responding to growing demand, Duke Energy, Amazon, Google, Microsoft and Nucore execute agreements to accelerate clean energy options." Duke Energy: News Center. 29 May 2024. https://news.duke-energy.com/releases/responding-to-growing-demand-duke-energy-amazon-google-microsoft-and-nucor-execute-agreements-to-accelerate-clean-energy-options

[52] Amanda Peterson Corio and Briana Kobor. "How we're working with utilities to create a new model for clean energy." Google: The Keyword. 11 June 2024. https://blog.google/outreach-initiatives/sustainability/google-clean-energy-partnership/

[53] "OPPD Welcomes Clean Capacity Collaborations as part of its Reliable Growth Plans." Omaha Public Power District. 14 May 2024. https://www.oppd.com/news-resources/news-releases/2024/may/oppd-welcomes-clean-capacity-collaboration-as-part-of-its-reliable-growth-plans/

[54] Ethan Howland. "AEP Ohio proposes data center, crypto financial requirements amid 30 GW in service inquiries." UtilityDive.com. 15 May 2024. https://www.utilitydive.com/news/aep-ohio-data-center-crypto-rates-puc/716150/

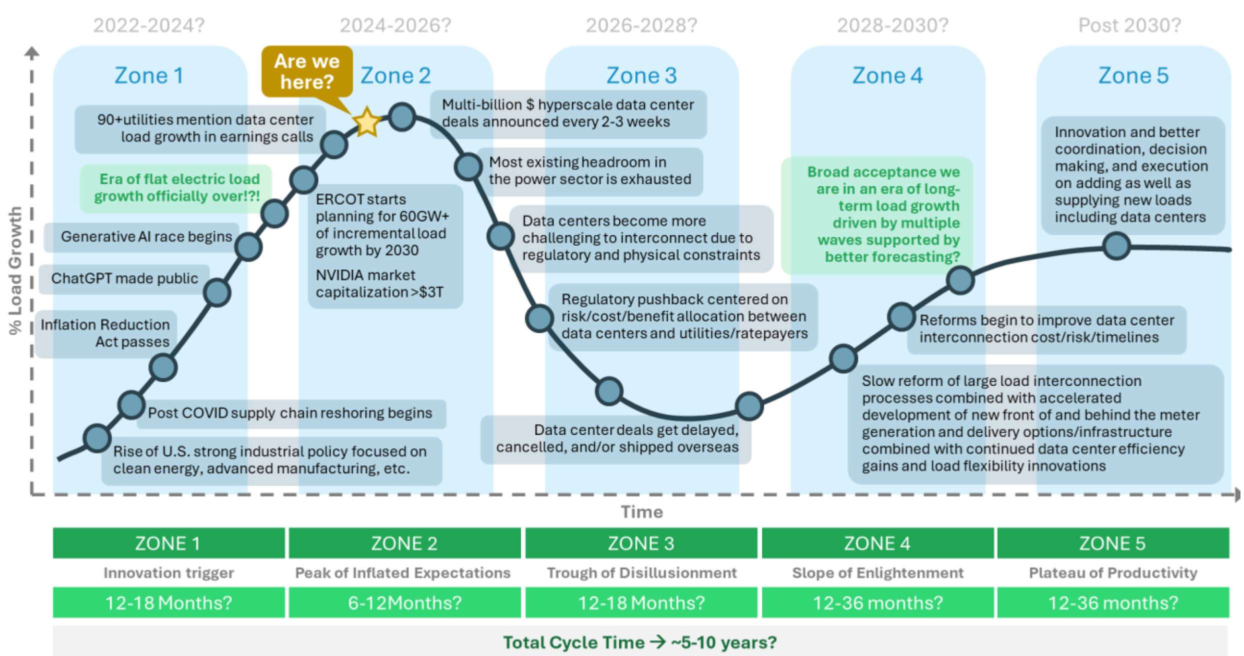
[55] Laila Kearney. "Duke Energy seeks take-or-pay power contracts for data centers." Reuters. 07 May 2024. https://www.reuters.com/business/energy/duke-energy-seeks-take-or-pay-power-contracts-data-centers-2024-05-07

E3's View

E3 works on hundreds of projects a year exclusively in the electric and gas sectors for a diverse range of clients, including state and federal agencies, utilities and market operators, regulators, and private industry, developers and investors. We believe this gives us a nuanced perspective on the challenges, issues, and potential solutions around near to longer-term load growth. The many questions we have been getting from our clients on the topic of data center load growth along with our current work on the topic motivated the creation of this whitepaper.

There is still much uncertainty at the macro and micro level regarding the scope and scale of data center growth. However, the key question should not be "How much will load grow?", but instead "Where and what kind of load growth can be accommodated in different jurisdictions?". As we crest the initial wave of a potential "hype" cycle shown in Figure 14 and growth expectations may reach their peak, stakeholders must begin to take hard looks at their abilities to meet different load scenarios and their options for doing so. Growth will occur, and its potential may ultimately be shaped by the energy sector's ability to accommodate that growth.

Figure 14: Are we in a Power Sector Data Center Hype Cycle? Illustrative Visualization based on Gartner Hype Cycle [56]



[56] "Gartner Hype Cycle" Wikipedia.com. Accessed 21 June 2024. https://en.wikipedia.org/wiki/Gartner_hype_cycle

Amidst this uncertainty, a coordinated approach with a clear understanding of cost and risk sharing and mitigation is essential. The integrated systems planning[57] approach with a different market construct is well-suited to matching supply and demand in systems with hard constraints on both. This would entail transitioning away from traditional planning approaches, which focus on incremental growth and a serial one-off or limited duration perspective, into a longer term and collaborative planning and execution model.

This type of approach would help realize optimal existing headroom allocation, increase energy affordability, and aid decarbonization efforts, all while enabling long-term strategic planning. As we enter a “new build” era with multiple waves of load growth, planners may need to adapt to operating in a constrained environment for the foreseeable future where scalable and innovative solutions on both the demand and supply side will be required.

Data center load growth could be a positive for the industry if leveraged effectively. Well-resourced customers with high load factors can help fund much-needed transmission grid upgrades and drive new clean energy supply. This could lead to cost savings for other customers if higher incremental sales are used to pay down the fixed costs (both existing and incremental) of the system. Furthermore, these customers can mitigate the risks and costs of bringing emerging technology generators (e.g. small modular reactors, advanced geothermal) to market and accelerate their adoption by becoming early customers for their power as well as anchoring other needed grid investments.

The surge in new electricity demand poses challenges, but also offers a unique opportunity to accelerate the transition to a cleaner, more reliable, and affordable energy future. The traditional paradigm of short-term incremental planning and reactive infrastructure development is no longer sufficient, especially in the face of continual waves of new load growth. A new approach is needed, one that embraces proactive planning, collaborative partnerships, and innovative solutions. Market participants and power planners should adapt and work together to develop a comprehensive and sustainable approach to meeting the nation's growing energy needs. The growth of data centers is not just a challenge to be overcome; it is an opportunity to build a better electric system for all.

[57] Integrated system planning (ISP) utilizes a cohesive integrated set of data, processes, and models to integrate generation and customer resource planning with transmission and distribution grid planning. This integration is critical to making decisions that balance making the right investments, in the right places, at the right times. As technology and participatory models advance, customers will increasingly be involved participants in this transition, requiring utilities and regulators to know when to support customer investments or behavioral changes over their own historical “wires” investments, while ensuring sufficient reliability and operational control over the broad and powerful set of emerging customer resources.

Appendix 1: Demand and Supply Forecasting Methodology and Sensitivities

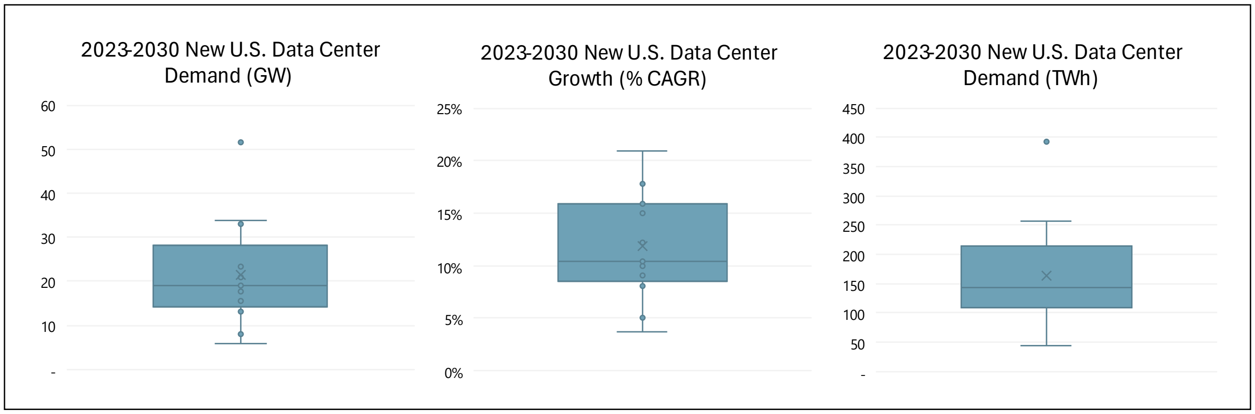
E3 used published data center projections to analyze and illustrate the potential new resource builds required to meet incremental annual energy demands driven by new data center development. E3 estimated new resource builds under a range of sensitivities examining lower energy demands from assumed incremental energy efficiency gains to computing and cooling data center operations.

Key assumptions for the analysis include:

- Load profile of a data center has an 86% load factor (average MWh/peak)
- 1.2 Power Usage Effectiveness (PUE) of new data centers is used as the starting point for further energy efficiency improvements
- 75% or 100% of new data center energy demand is met by renewables (wind and solar) in any year with gas meeting the remainder
- Any new renewables generation is comprised of 70% solar and 30% wind, with respective capacity factors of 22% and 36%; other capacity generation assumes a 54% capacity factor
- For the effective capacity analysis, E3 makes simplified assumptions of Effective Load Carrying Capability (ELCC) values (*Note: the use of ELCC values in this analysis is for illustrative purposes only and does not provide a comprehensive assessment for true reliability planning*)
    - Solar, Wind, and Firm Capacity resources assume respective ELCC values of 0.2, 0.21, and 0.95 for all years
    - Solar + Storage resources assume an ELCC value of 0.5 in 2024, declining linearly to 0.35 in 2030;
    - assumes half of solar nameplate capacity is paired with short-duration battery storage

E3's Data Center Demand Projections Using Various Public Sources

The estimates of new data center demand, compound annual growth rate (CAGR), and energy demand are based on a review of data center projections from JLL[58], McKinsey[59], EPRI[60], IEA[61], BCG[62], Mordor[63] and Goldman Sachs[64] illustrated below. The box-and-whisker plots compile 13 projections, including four sensitivities from EPRI (Low, Moderate, High, and Higher scenarios) and three from Goldman Sachs (Bear, Base, Bull scenarios). Sources provide projections in terms of forecasted data center capacity (e.g. MW) or energy demand (e.g. MWh). Where applicable, E3 estimates data center capacity from energy estimates or vice-versa using an assumed 86% load factor.



[58] Kari Beets. "North America Data Center Report." JLL. 28 February 2024. https://www.us.jll.com/en/trends-and-insights/research/na-data-center-report

[59] Srini Bangalore, Arjita Bhan, Andrea Del Miglio, Pankaj Sachdeva, Vijay Sarma, Raman Sharma, and Bhargs Srivathsan. "Investing in the rising data center economy." McKinsey & Company. 17 January 2023. https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy

[60] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." EPRI. 2024. https://www.wpr.org/wp-content/uploads/2024/06/3002028905_Powering-Intelligence_-Analyzing-Artificial-Intelligence-and-Data-Center-Energy-Consumption.pdf

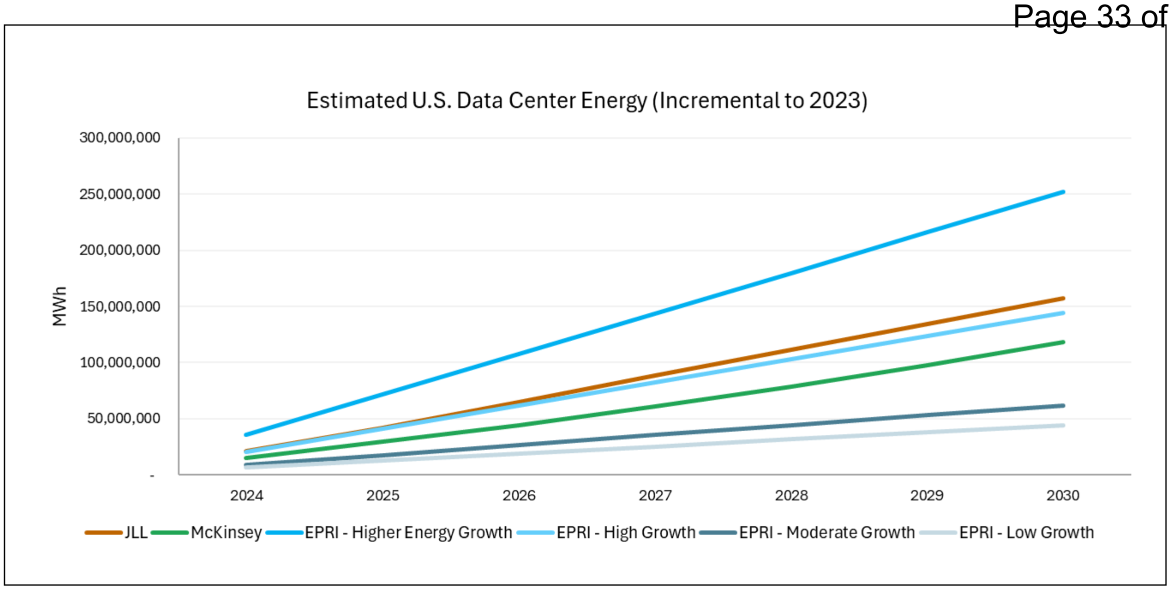
[61] "Electricity 2024: Analysis and forecast to 2026." IEA. 19 January 2024. https://iea.blob.core.windows.net/assets/6b2fd954-2017-408e-bf08-952fdd62118a/Electricity2024-Analysisandforecastto2026.pdf

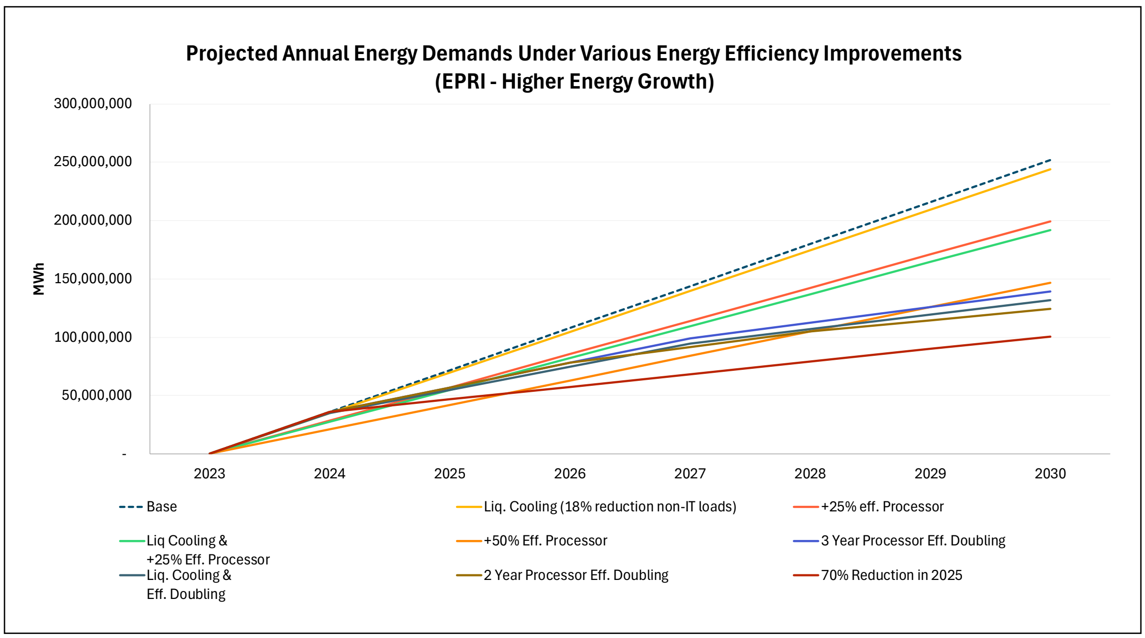
[62] "The Impact of GenAI in Electricity." Boston Consulting Group. 2024. https://www.linkedin.com/posts/bcg-on-energy_the-impact-of-genai-in-electricity-activity-7112787574032674816-uDEX/

BCG's "US Data Center Power Outlook" report issued in July 2024 provides its more updated view, projecting new data center demand growth ranging from 60 to 90 GW in 2023-2030.

[63] "United States Data Center Market Size & Share Analysis – Growth Trends & Forecasts Up to 2029." Mordor Intelligence. https://www.mordorintelligence.com/industry-reports/united-states-data-center-market

[64] "Generational Growth: AI, data centers and the coming US power demand surge." The Goldman Sachs Group, Inc. 28 April 2024. https://www.goldmansachs.com/intelligence/pages/gs-research/generational-growth-ai-data-centers-and-the-coming-us-power-surge/report.pdf.





Energy Efficiency Demand Sensitivities

Assuming a new interconnected data center has a power usage effectiveness (PUE) of 1.2, this means the facility's total energy use is divided into 83% for IT demand and 17% for non-IT demand (such as cooling). E3 applied various improvements to IT power consumption, non-IT power consumption, or both.

Processor efficiency is assumed to impact all IT energy loads. Therefore, a 25% gain in processor efficiency reduces the IT load share of the facility-wide demand from approximately 83% to 63%. When combined with non-IT loads, which maintain their 17% share of the base case facility-wide energy demands, the new facility-wide demand is estimated to be around 80% of the base case (63% + 17%).

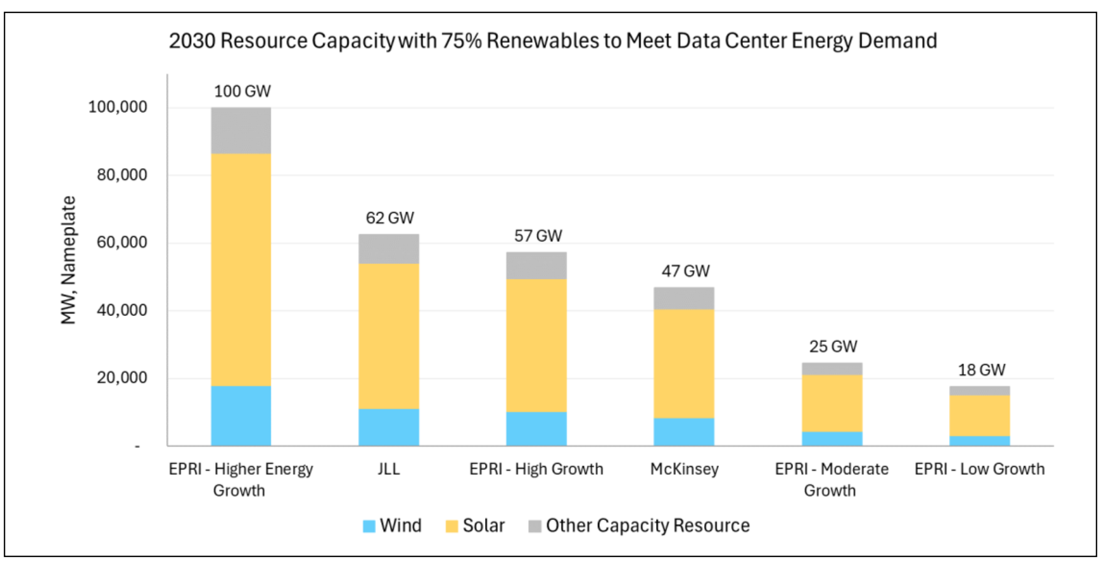
Interactions between IT and non-IT energy demands resulting from improvements to processor efficiency are not explicitly accounted for. This analysis also assumes that the end-use computing demands remain constant despite improved efficiency. This means the base case energy use serves a fixed amount of computing tasks and the possibility that enhanced IT efficiency could lead to induced computing and power demand, as facility operators seek to maintain high utilization, is not considered.

Under these hypothetical efficiency improvements and assumed schedules, facility-wide power demand of newly interconnected data centers are reduced relative to the base case (100%) as shown in the following table. Not all energy efficiency scenarios are depicted in the resource builds.

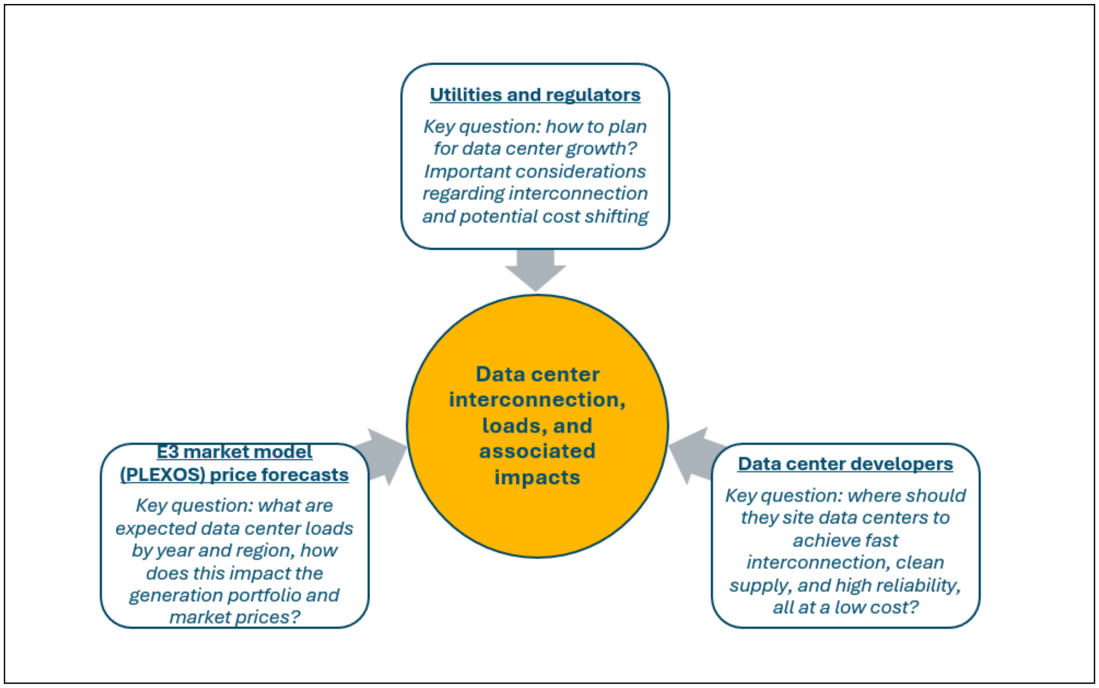
Energy Efficiency Demand Sensitivities: New Data Center Facility-Wide Energy Consumption Relative to Base Case

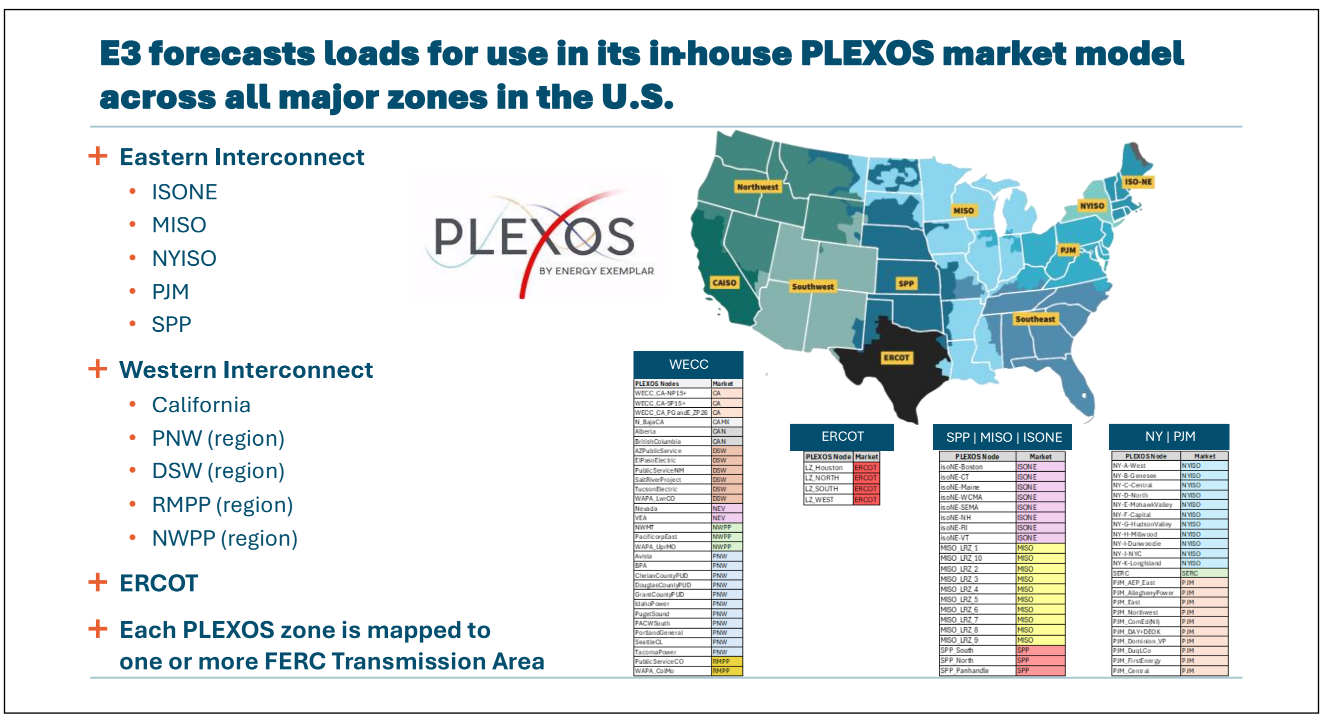
	2024	2025	2026	2027	2028	2029	2030
Base	100%	100%	100%	100%	100%	100%	100%
Liq. Cooling (18% reduction non-IT loads)	97%	97%	97%	97%	97%	97%	97%
+25% eff. Processor	79%	79%	79%	79%	79%	79%	79%
Liq Cooling & +25% Eff. Processor	76%	76%	76%	76%	76%	76%	76%
+50% Eff. Processor	58%	58%	58%	58%	58%	58%	58%
3 Year Processor Eff. Doubling	100%	58%	58%	58%	38%	38%	38%
Liq. Cooling & Eff. Doubling	97%	55%	55%	55%	35%	35%	35%
2 Year Processor Eff. Doubling	100%	58%	58%	38%	38%	27%	27%
70% Reduction in 2025	100%	30%	30%	30%	30%	30%	30%

The figure below depicts the estimated nameplate capacity of resources necessary to provide sufficient annual energy demand across various data center growth projections. Figure 9 in the report shows the same builds but also indicates the range of build uncertainty accounting for the following hypothetical energy efficiency improvement scenarios: base, liquid cooling, +25% efficient processor, liquid cooling & +25% efficient processor, +50% efficient processor, and 2-year processor efficiency doubling.

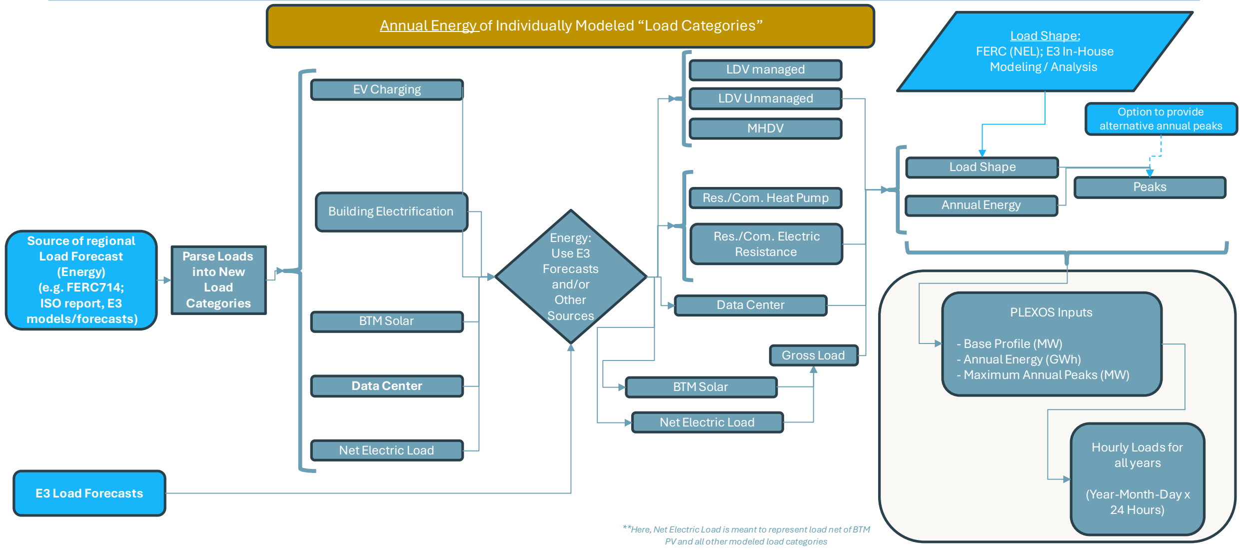


Appendix 2: E3's Load Forecasting Approach Currently Incorporated in Our U.S. Wide PLEXOS Market Model





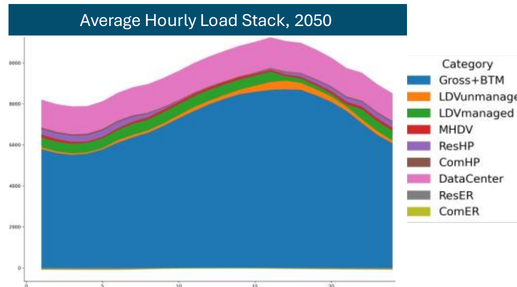
General E3 Process Flow for Modeling Major New Future Loads including Data Centers



Example Total Load Buildup for a Data Center Heavy Utility

- **PLEXOS generates hourly loads for each load category, in each zone**
  - E3 models baseload as gross load net of electrical resistance heating load to account for fuel switching to heat pumps in the future
- **Each load type is summed for each hour to assess total energy, peaks, system shape**

Average Hourly Load Stack, 2050



Get a Load of This

Regulatory Solutions to Enable Better Forecasting of Large Loads

Report / February 2025

Authors and Acknowledgments

Authors

Jeffrey Sward
Lauren Shwisberg
Katerina Stephan
Jacob Becker

All authors are from RMI unless otherwise noted.

Contacts

Jeffrey Sward, jsward@rmi.org
Lauren Shwisberg, lshwisberg@rmi.org

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Jeffrey Sward, Lauren Shwisberg, Katerina Stephan, and Jacob Becker, *Get a Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads*, RMI, 2025, **https://rmi.org/insight/get-a-load-of-this**.

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Acknowledgments

The authors would like to thank the following individuals for their contributions to this work as reviewers:

Madison Bolton, Public Utilities Commission of Oregon
Edward Burgess, Current Energy Group
Ben Deitchman, Georgia Public Service Commission
Mark Dyson, RMI
Tyler Fitch, RMI
Anson Justi, Public Service Commission of Maryland
Taylor McNair, GridLab
Steve Olea, Arizona Corporation Commission
Maria Roumpani, Current Energy Group

In addition, the authors would like to acknowledge the faculty and public utility commission staff who participated in the second Regulatory Collaborative (**Reg Lab**) cohort, Near-Term Responses to Potential Load Growth. Although much of the content for this report was inspired by the presentations, conversations, and discussions in the cohort, this report is solely the responsibility of the authors and does not reflect the perspectives of participants or their organizations.

About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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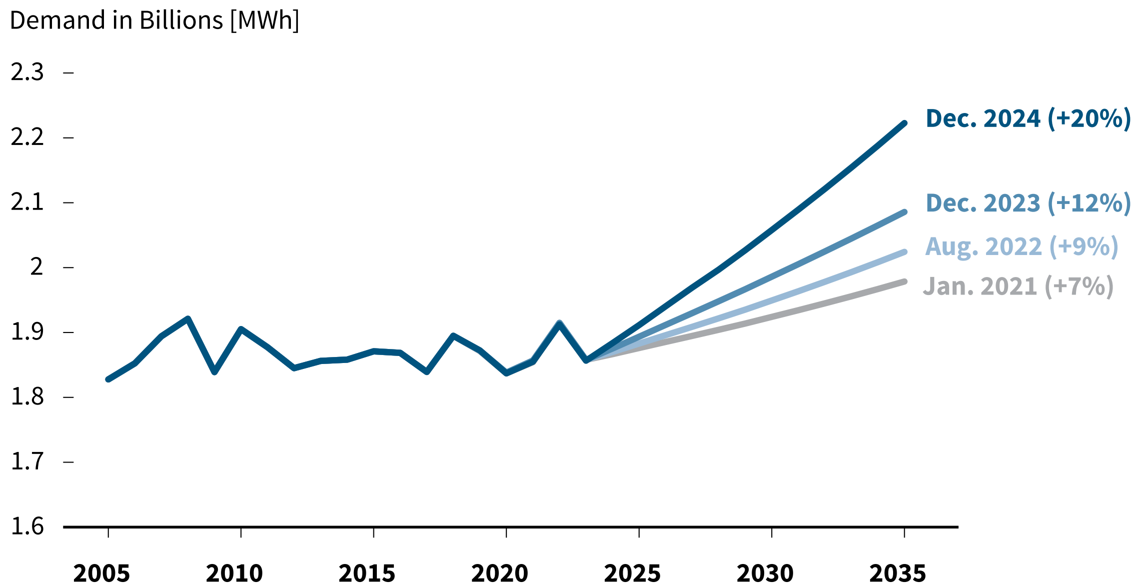
Executive summary

In the United States, electricity demand, or load, has begun to grow following several decades without growth. Utility integrated resource plans (IRPs) from utilities covering 48% of sales to US customers expect load to grow 20% from 2023 through 2035, and utilities continue to make upward revisions in their load forecasts (see Exhibit ES1).

Exhibit ES1 Projected electricity demand (load) in IRPs



Note: Data includes projections from 121 IRPs, covering 48% of electricity delivered to US customers. The percent of change is for 2023 to 2035.

RMI Graphic. Source: RMI Engage & Act, https://rmi.org/our-work/climate-finance/engage-and-act/

Load forecasting is the process of predicting the time, location, and scale at which loads will materialize and how they will operate. This report focuses primarily on long-term (10-plus year) forecasts that utilities use for planning. Long-term load forecasts are the backbone of utility investment plans. The IRP forecasts in Exhibit ES1 are the basis for billions of dollars of proposed investments between 2023 and 2035, including 260 gigawatts (GW) of wind and solar additions, 84 GW of gas additions, and 74 GW of coal retirements, which are subject to regulatory approval.

Improving load forecasting can create two main benefits. It can:

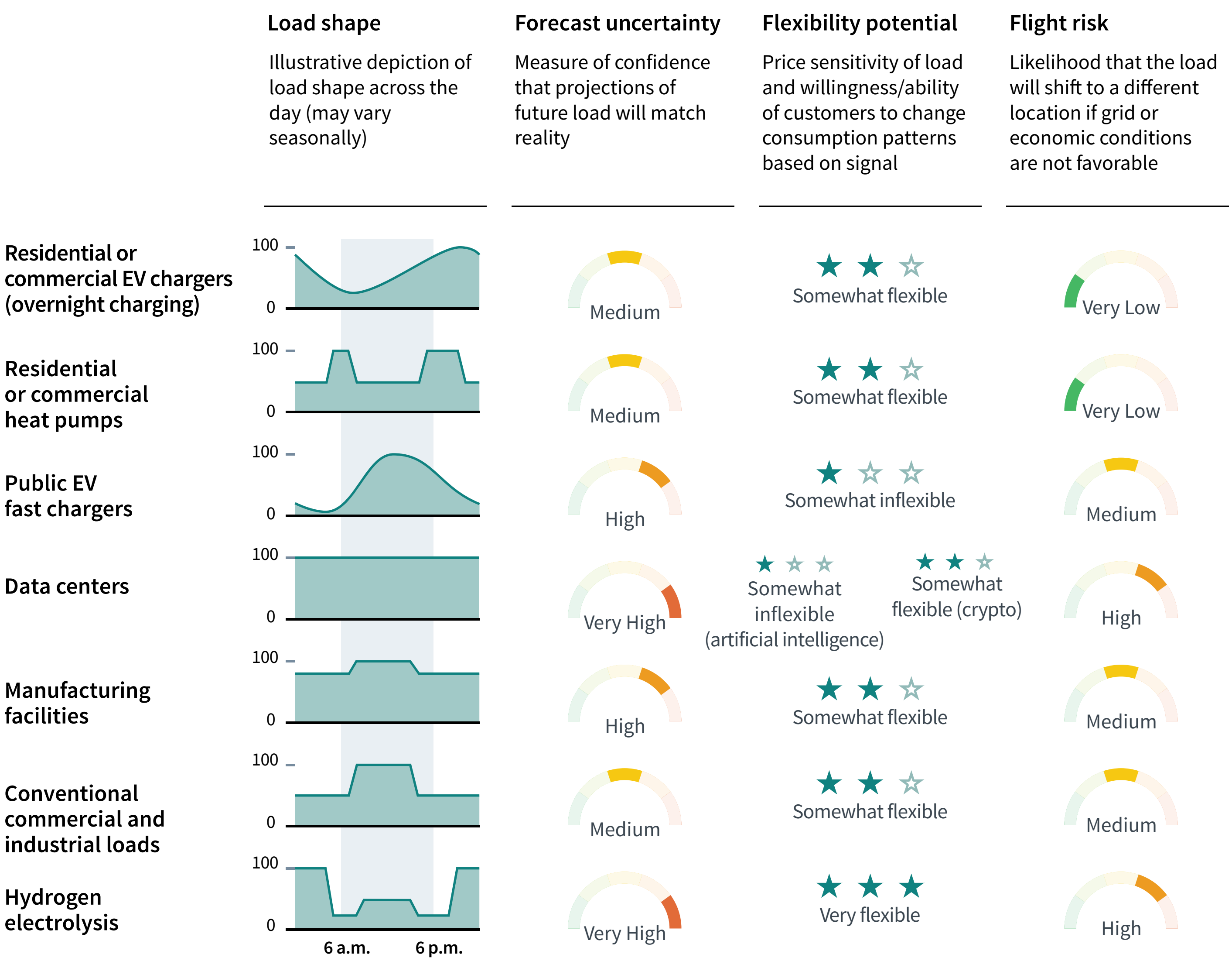
- Mitigate affordability and reliability risks. Good forecasting is the first line of defense in managing the major risks of systemic forecasting error. Customer affordability is the main risk of over-forecasting, and reliability is the main risk of under-forecasting.

- Create an opportunity to consider all available investment options. When utilities are caught off guard by under- or over-forecasts, investment options become more reactive and limited.

Given their rapid rise and massive capacities relative to existing systems, drivers of new large loads (e.g., data centers, advanced manufacturing, heavy transportation, industrial electrification) have unique characteristics that should be captured in modern forecasting processes: their load shape, forecast uncertainty, flexibility potential, and flight risk (see Exhibit ES2).

Exhibit ES2 **Not all load is equal: key characteristics of how load types affect the grid can vary significantly**

Key characteristics of how load types impact the grid can vary significantly



RMI Graphic. Source: RMI analysis

Forecasters can apply several best practices to improve forecasts regardless of the characteristics of coming loads:

- Employ scenario-based or stochastic load forecasting methods to better understand the range of possible futures and identify major sources of uncertainty, rather than relying on a single forecast to get it right.
- Integrate end-use forecasting with econometric forecasting to adjust forecasts based on economy-wide trends and historical data. This helps to more adequately capture the adoption and operation of loads that have not yet reached market saturation or do not correlate with typical macroeconomic indicators (e.g., electric vehicle [EV] adoption).
- Ensure load forecasts are used consistently across planning processes so that decisions in different processes are based on the same underlying set of data and assumptions.

Approaches to integrating new large loads into forecasts are nascent, with examples in regions that are projecting rapid growth, such as Georgia, North Carolina, and Virginia. New large loads exacerbate three major forecasting challenges, as depicted in Exhibit ES3.

Exhibit ES3 Goals for modernizing forecasts to integrate large loads

Challenges with load forecasts today	Goals for load forecasts
Limited: Load forecasts may not include the relevant characteristics of large loads.	**Thorough:** Ensure load forecasts accurately reflect the unique characteristics of large loads to their best ability.
Outdated: Load forecasts that are updated annually do not match the current pace of change.	**Up-to-date:** Increase the frequency of updating both load forecasts and load forecasting processes.
Opaque: Load forecasts can rely on inaccessible data, making bias tracking infeasible.	**Validated:** Make load forecast data and processes visible to other stakeholders and create opportunities for accountability.

RMI Graphic

While utilities and grid operators develop forecasts, regulators have three critical roles with respect to forecasts: (1) establish guidelines for forecasting, (2) review and approve utility forecasts, and (3) ultimately approve or deny cost recovery for investments made based on forecasts.

Regulators can take several actions to align forecasts toward the goals in Exhibit ES4. These actions were informed by discussions with regulators, industry experts, and RMI staff in RMI's second Regulatory Collaborative (**Reg Lab**) cohort.[i]

Exhibit ES4 Actions for regulators

Goals for load forecasts	Actions regulators can take
Thorough	• Increase commission and utility understanding of new loads by initiating technical conferences or investigatory proceedings or by engaging informally with stakeholders. • Revise planning guidelines to incorporate emerging forecasting practices for new loads, such as establishing a separate large load forecast and processes to avoid double counting (see *Appendix: Discovery questions for load forecasting*). • Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads.
Up-to-date	• Require more frequent reporting of long-term load forecasts, such as quarterly. • Iterate forecasting processes as new practices and end uses emerge so that forecasts remain current.
Validated	• Encourage utilities to leverage transparent external data and forecasting tools where possible so that stakeholders and the commission can play an active role in vetting assumptions. • Make forecasts and actuals accessible and learn from past forecasts to assess past forecast accuracy and identify sources of error. • Explore monetary incentives or penalties for forecasts based on accuracy, including tariffs that shift risk to the specific large customers driving load growth or to the utility.

RMI Graphic

i Reg Lab is a cohort-style initiative that builds regulatory staff capacity and develops cutting-edge solutions to today's pressing issues. Regulators from 15 states joined experts from across the country to explore near-term options to potential load growth in seven virtual workshops. For more information on previous and future cohorts, please see: **https://rmi.org/reg-lab/**.

Even when best practices are adopted, all forecasts remain uncertain. However, with rapid load growth projected, utilities and commissions must be able to make decisions despite significant forecast uncertainty. Regulators can refine their decision-making toolkit to mitigate the risks of forecast uncertainty. They can:

- Prioritize "least-regrets" capital investments, including investments that are currently fast, affordable, and flexible (e.g., energy efficiency, virtual power plants [VPPs], grid-enhancing technologies, reconductoring, and clean repowering) and that are robust and provide benefits under a wide range of possible futures (e.g., interregional transmission).

- Use tariff design or other contractual commitments to allocate risk and shore up uncertainty, by implementing tariff structures or rate changes that allocate some of the risk back onto large customers driving growth.

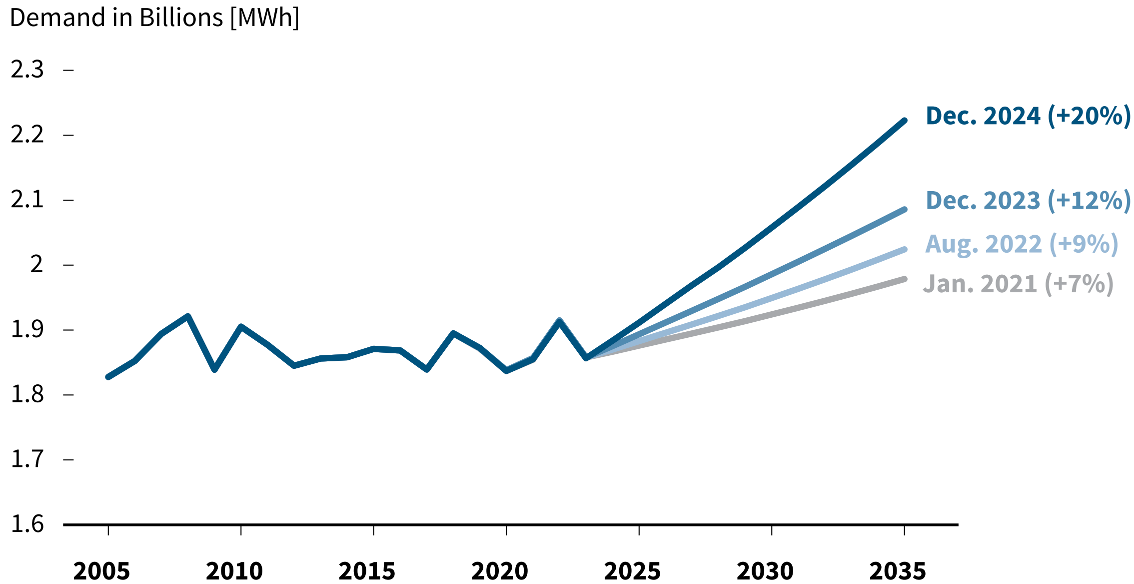
These actions are the first steps utilities and commissions can take to mitigate the affordability and reliability risks of forecasting, but there is a need for more research. More publicly available and easily accessible data characterizing the developmental timelines and operational patterns of these loads would improve forecasting accuracy. New research can help identify methods to better deconflict economy-wide forecasts and end-use forecasts and propose new processes that go beyond econometric modeling. Even though all forecasts are wrong, the scale of projected load growth and its potential risks create an imperative to ensure that forecasts remain useful in guiding consequential regulatory decisions.

Load is growing and projections are growing faster

Between 2022 and 2024, grid planners increased the five-year peak load forecast from 23 GW of projected new load to 128 GW.[1] As of December 2024, utility IRPs representing 48% of electricity sales in the United States expected load to grow 20% through 2035, up from 7% in January 2021.[2] Today's forecasts are flipping the classic North American Electric Reliability Corporation (NERC) fan upside down[3] — in place of consistent downward revisions in forecasts, utilities are currently making consistent upward revisions in forecasts (see Exhibit 1).

Exhibit 1

Projected electricity demand (load) in IRPs

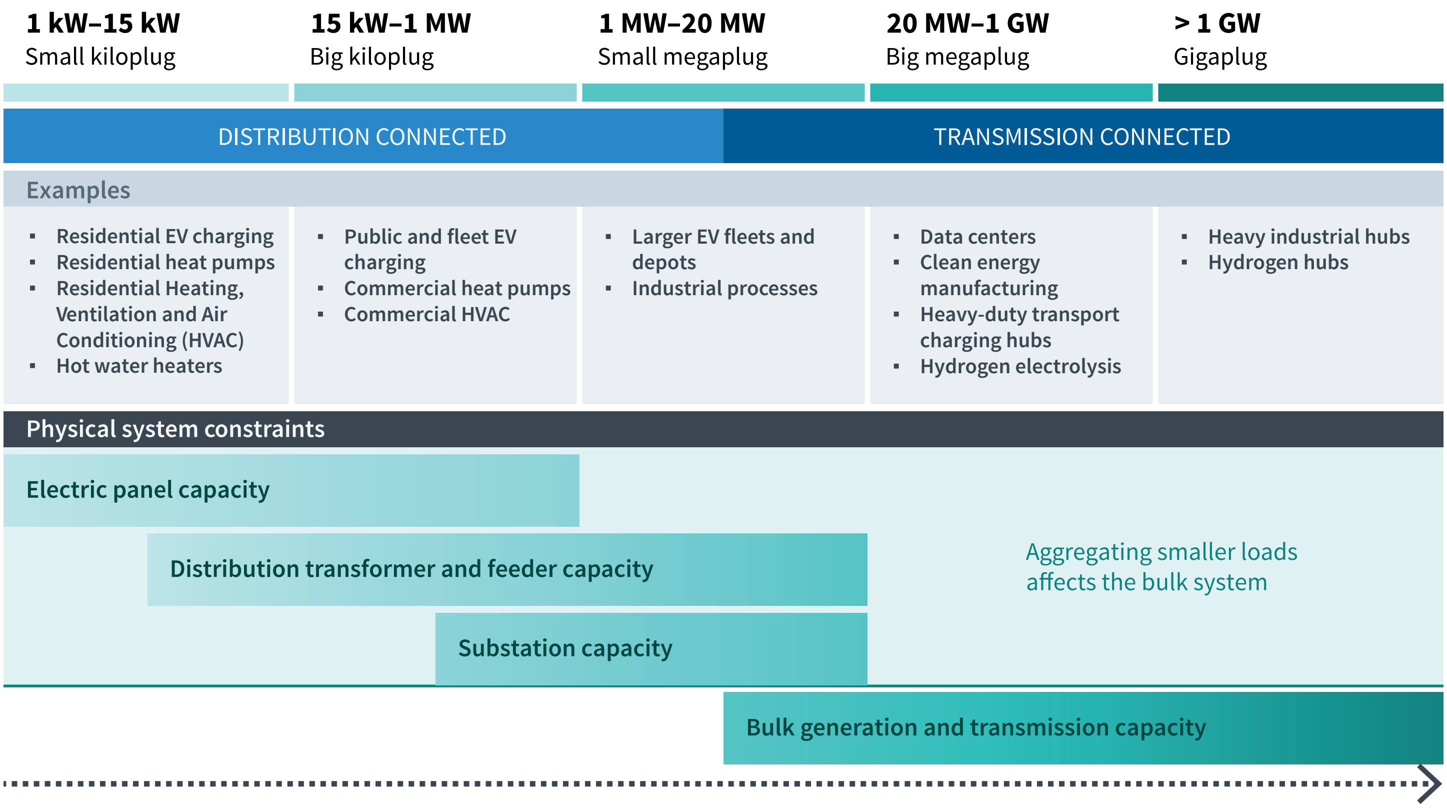


Note: Data includes projections from 121 IRPs, covering 48% of electricity delivered to US customers. The percent of change is for 2023 to 2035.

RMI Graphic. Source: RMI Engage & Act, https://rmi.org/our-work/climate-finance/engage-and-act/

From residential consumers to companies, electricity users of all sizes are seeking to connect to the distribution and transmission grids, driving that forecasted load growth. Exhibit 2 depicts the potential effects of load growth across all levels of the system. On the transmission system, the main drivers behind load growth include new manufacturing, industrial, and data center facilities as well as large-scale charging infrastructure for EVs. On the distribution system, EV charging and electrified heating are emerging as new demands and new resources. To support these distributed end uses, broader infrastructure upgrades deployed at scale are necessary. Given the many new end uses with unique characteristics compared with traditional end uses, forecasting approaches must advance so utility planning can keep the grid reliable and costs down.

Exhibit 2 Load growth affects all levels of the grid



RMI Graphic. Source: RMI analysis

Several types of load growth drivers are showing up in utility plans across the country, as summarized in Exhibit 3.[4] In the near term, data centers and advanced manufacturing represent the largest drivers of growth in the Southeast, the Rust Belt, and numerous tech hubs across the United States. Their large loads pose unique forecasting challenges for utilities and grid operators.

Exhibit 3 Near-term load drivers for 11 large utilities and independent system operators or regions

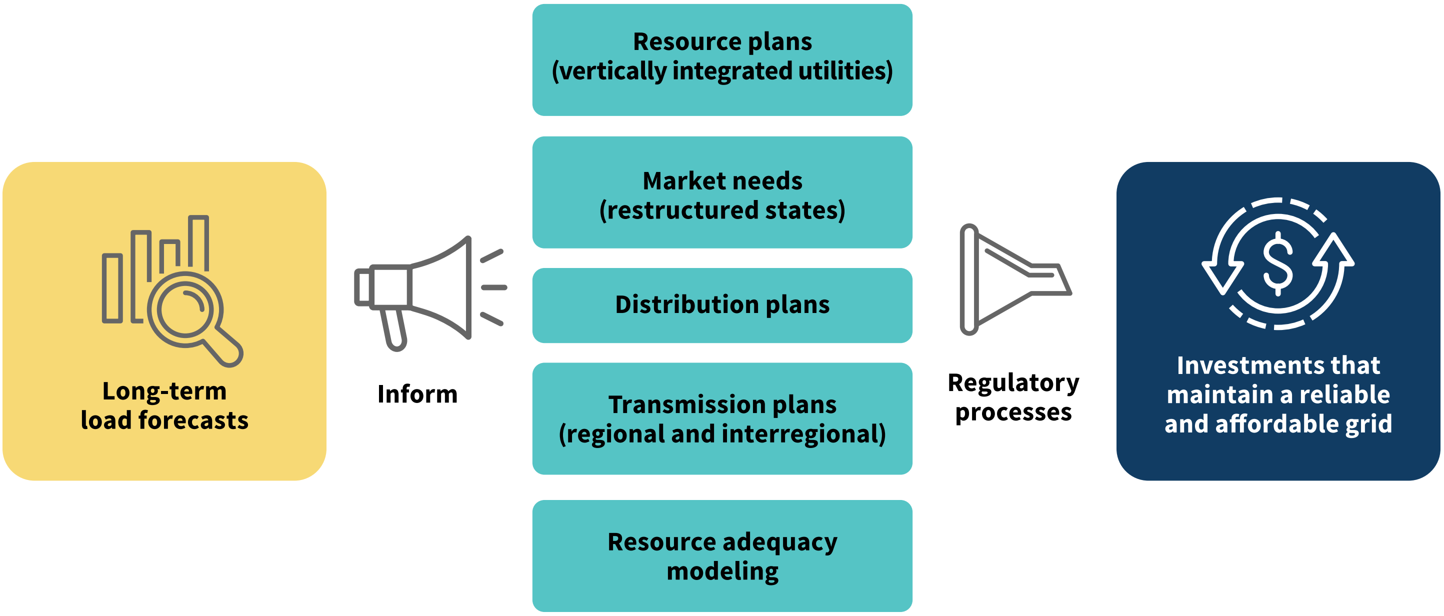
Near-Term Load Drivers	Data Centers	Manufacturing	Electrification
Arizona Public Service	✓		
CAISO	✓		✓
Duke	✓	✓	
ERCOT	✓	✓	
Georgia Power	✓	✓	
ISO-NE			✓
MISO	✓		✓
NYISO	✓	✓	✓
Pacific Northwest	✓	✓	
PJM	✓	✓	✓
SPP	✓		

RMI Graphic. Source: Grid Strategies, https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

Load forecasting is the process of predicting the time, location, and scale at which loads will materialize and how they will operate. Utilities typically develop forecasts for multiple purposes across many time scales. These range from daily operational forecasts to quarterly sales estimates, to 10- to 20-year long-term planning forecasts.

This report focuses primarily on long-term forecasts that utilities use for planning. Long-term load forecasts form the backbone of resource plans that ultimately justify utility infrastructure investment decisions and affect the quality of electric service — that is, the ability to create and maintain a system that provides reliable energy, capacity, and grid services at a fair price for all customers. Utilities seek to forecast electricity needs, both total energy consumption and peak load, for each segment of their customer base, traditionally residential, commercial, and industrial. In addition to justifying a preferred portfolio of new generation resources, long-term load forecasts inform market needs for utilities in restructured states, distribution system upgrades, regional transmission upgrades, and resource adequacy modeling (see Exhibit 4). In addition, individual utility load forecasts often feed into regional transmission organization load forecasts that assess the need for bulk system transmission upgrades and interregional transmission.

Exhibit 4 Load forecasts influence key regulatory proceedings; however, the ultimate investment decisions must filter through regulatory processes and gain regulatory approvals



RMI Graphic

Accurate, frequent, and accountable load forecasts offer the first line of defense in mitigating the key risks that large load additions pose: affordability and reliability. Forecasts are used to justify billions of dollars worth of investments. As of December 2024, US utility resource plans had proposed 260 GW of wind and solar additions, 84 GW of gas additions, and 74 GW of coal retirements between 2023 and 2035.[5] Furthermore, in 2024, Edison Electric Institute projected that US investor-owned utilities would make a historic $168.2 billion in capital expenditures during 2025 alone.[6]

Despite these investments, a number of factors necessitate updated forecasting processes: the pace at which businesses would like to interconnect new loads compared with the speed of regulatory processes, the scale of these loads compared with existing utility service, the uncertainty in their timing, and their operational characteristics. While advanced forecasting practices have already begun to take shape for smaller distributed loads, emergent large load drivers have yet to be systematically integrated into many utility plans.[7] Backlogged interconnection queues, congested transmission systems, and increasingly frequent and severe extreme weather events further exacerbate reliability risks as load growth and retirements threaten to outpace the deployment of new generation.

Improving large load forecasts can broaden the set of options that utilities and regulators might consider to serve the load. When utilities are caught off guard by new loads, options become limited. Throughout 2024 this has become clear: forecasted load growth is currently resulting in utility commitments to options that are quick or familiar, such as delayed retirements and new gas proposals. These solutions are driving up forward-looking emissions estimates, increasing exposure to fuel cost risk, and denying the cost savings that would come from swapping older units for newer more efficient ones.

This report explores today's large load drivers, details how leading utilities and independent system operators are integrating large loads into their forecasts, and establishes a set of modern load forecasting best practices to aid regulators in navigating this new era of development.

Further reading

- For an exploration of the rapidly changing landscape of load drivers and how they complicate load forecasting for utilities and system operators, see ***Electricity Demand Growth and Forecasting in a Time of Change***, Brattle, May 2024.
- For a deep dive into recent load growth drivers, see ***The Era of Flat Power Is Over***, Grid Strategies, 2023.

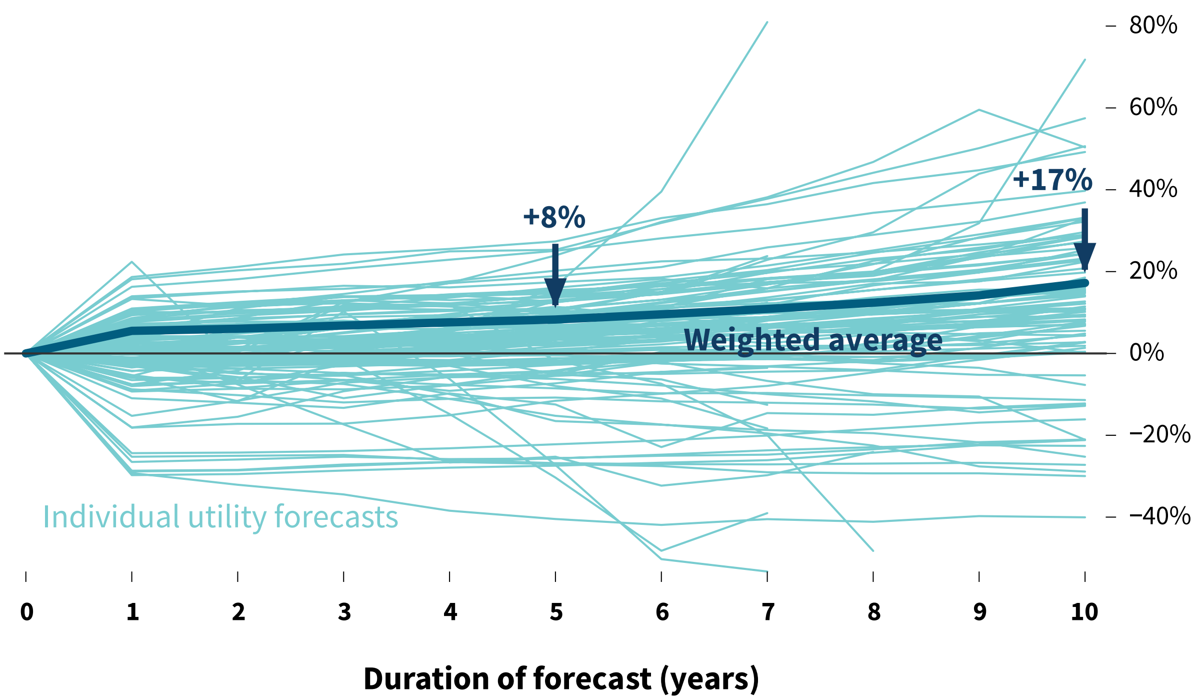
Regulators must seek to mitigate the risks of both under- and over-forecasting

In an ideal world, utilities would perfectly forecast load and regulators would have the confidence to approve proactive infrastructure investments that would save customers money over the long run. In reality, predicting the future accurately is challenging. As a result, regulators have a role to understand and mitigate the risks associated with load forecast errors.

Historical over-forecasting

Historically, utilities have systematically over-forecasted electricity demand, which indicates an opportunity to improve forecasting processes. Between 2006 and 2023, utility planners, on average, over-forecasted electricity demand by 8% in 5-year forecasts and by 17% in 10-year forecasts (see Exhibit 5). The forecast error is even higher for more recent years: data from 2012 to 2023 shows that forecasts were, on average, 23% higher than actuals.

Exhibit 5 **Electricity planning area peak demand forecast error 2006-23**



RMI Graphic. Source: RMI analysis of FERC Form No. 714 data

A 2017 RMI study that reviewed historical load forecasts highlighted three systemic factors that contribute to over-forecasting, all of which are relevant to today's challenges:[8]

1. Underestimating improvements in energy efficiency. Many utilities traditionally used a measure of energy consumption per customer, which has declined over the past several decades due to improvements in energy efficiency. Despite high energy intensity in large new data center loads, economy-wide energy intensity is expected to continue declining. Forecasters should strive to capture efficiency trends across sectors in both top-down and bottom-up modeling approaches.

2. Over-forecasting is more aligned with traditional utility incentives. For states without modernized utility business models, utilities are incentivized to build more infrastructure because they earn a rate of return on capital investments,[9] and this incentive is stronger if the allowed rate of return is higher than a utility's cost of capital. Although keeping rates affordable is a priority, specifically attributing rate increases to instances of over-forecasting is not straightforward.

3. Under-forecasting can lead to resource adequacy challenges for which utilities are accountable. In some cases, under-forecasting can lead to load shedding, brownouts, or blackouts during extreme conditions, which are felt acutely by customers. Furthermore, such resource adequacy issues have no simple solution. Leaning more heavily on both market purchases and emergency investments can create additional costs, which ultimately are borne by ratepayers.

The mismatch in the time required to permit and build new supply-side resources (as long as 10 years) and the speed at which some new large loads are ready to be interconnected exacerbates these dynamics. For example, data centers can be constructed far faster than traditional industrial facilities (i.e., they can come online within one to two years). However, because data centers turn over hardware on a two-year cycle, even if resource plans use the most up-to date hardware information, they will be several cycles behind by the time the planned resources arrive to meet the demand. Given that algorithmic efficiency for applications based on artificial intelligence (AI) remains a relatively new field, efficiency gains will likely be realized in the future both on software and in the underlying hardware.[10]

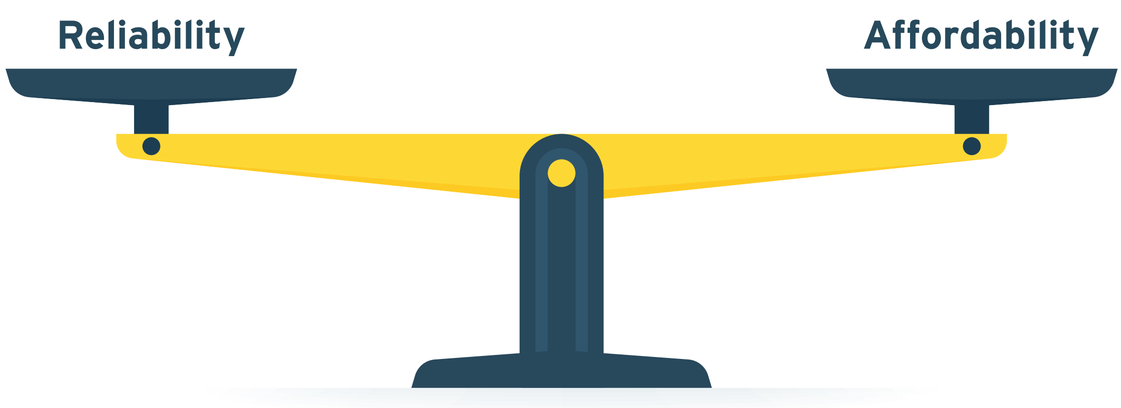
Risks from under- and over-forecasting and opportunities to mitigate them

Forecasting is an opportunity to balance the risks of affordability and reliability, and either under-forecasting or over-forecasting can tip the scale (see Exhibit 6).

Under-forecasting primarily represents a risk to reliability and achieving policy priorities such as economic development, which affects utilities and their investors, policymakers, and customers. Furthermore, in restructured markets, insufficient capacity can increase customer bills, making them less affordable (e.g., consumers will pay $14.7 billion for capacity in PJM during the 2025–26 delivery year, up from just $2.2 billion in the 2024–25 delivery year).[11]

Customer affordability is the primary risk associated with systematic over-forecasting when it leads to over-investment. Some checks on this are embedded in the current regulatory paradigm, such as regulators' ability to withhold approval of investment until utilization rates of existing infrastructure meet a certain criterion. In some cases, prospective investments fail to pass a prudence review. Over-forecasting can also shift focus or funding toward system expansion and away from maintenance. With 70% of transmission lines more than 25 years old and approaching the end of their typical life span,[12] maintenance investments in the existing system are increasingly critical.

Exhibit 6 Load forecasting is an exercise in balancing reliability and affordability



RMI Graphic

Load characteristics critical for forecasting

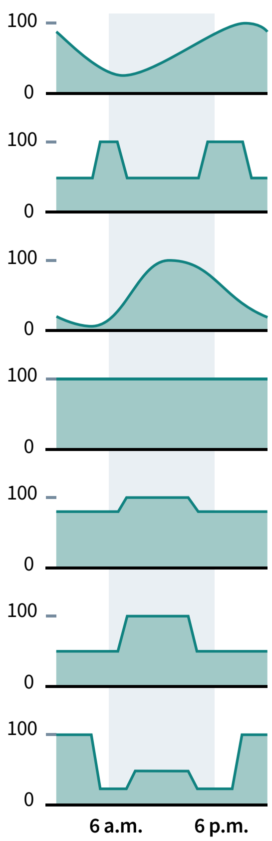
New loads come with unique characteristics and timing that are important to reflect in forecasts because they change the options for future resource investment. Following is a framework highlighting specific load characteristics that can aid planning discussions about load growth.

Whereas load growth affects all levels of the grid, the effect of an individual load depends on several defining characteristics (see Exhibit 7).

- **Load shape:** Loads that operate during peak times or that are concentrated within a season where they coincide with many other loads are more likely to require grid upgrades or new generation. How the load will change over time, including whether there is a ramp-up period to full operation, can unlock additional resource options.
- **Forecast uncertainty:** How accurately loads can be projected into the future depends on weather, economics, customer behavior, and variations in device program offerings and defaults. Weather and customer behavior are difficult to predict accurately, leading to uncertainty in forecasts looking hours or days into the future, let alone years.
- **Flexibility potential:** Many more loads need to be connected to the grid, but a grid where all loads operate at the same time exacerbates emissions and cost challenges. Ideally, new loads drivers operate flexibly and pay more for drawing power during times of stress on the grid. Knowing the level and timing of flexibility that a load can offer can reduce the required generation capacity or can be used to design new flexibility incentives or programs.
- **Flight risk:** All businesses need electricity. Some need tons of electricity. Some require cheap power. Many need a skilled workforce nearby. These dynamics influence where load drivers choose to connect in the first place and the likelihood that changing market or economic conditions may convince them to contract or expand existing operations or shift new operations elsewhere.

Exhibit 7 Not all load is equal: key characteristics of how load types affect the grid can vary significantly

Key characteristics of how load types impact the grid can vary significantly



	Load shape	Forecast uncertainty	Flexibility potential	Flight risk
	Illustrative depiction of load shape across the day (may vary seasonally)	Measure of confidence that projections of future load will match reality	Price sensitivity of load and willingness/ability of customers to change consumption patterns based on signal	Likelihood that the load will shift to a different location if grid or economic conditions are not favorable
Residential or commercial EV chargers (overnight charging)		Medium	★★☆ Somewhat flexible	Very Low
Residential or commercial heat pumps		Medium	★★☆ Somewhat flexible	Very Low
Public EV fast chargers		High	★☆☆ Somewhat inflexible	Medium
Data centers		Very High	★☆☆ Somewhat inflexible (artificial intelligence); ★★☆ Somewhat flexible (crypto)	High
Manufacturing facilities		High	★★☆ Somewhat flexible	Medium
Conventional commercial and industrial loads		Medium	★★☆ Somewhat flexible	Medium
Hydrogen electrolysis		Very High	★★★ Very flexible	High

RMI Graphic. Source: RMI analysis

The old, the new, and the revived — deep dives into large electricity load end uses

New large loads in particular present a challenge to forecasters. This section details the characteristics of two of these large loads: data centers and industrial and manufacturing loads.

Data centers

Data centers are a well-established end use made relevant by the recent rise in power-hungry large language models and proof-of-work cryptocurrency mining. Load growth from data centers is expected to be geographically uneven, which may present local challenges as 15 states currently account for 80% of the national data center load. For example, data centers are estimated to comprise 25.6% of Virginia's electric load in 2023, and higher growth estimates predict that share increasing to 46% by 2030.[13]

Load shape and flexibility potential

There are several types of data centers, each with unique flexibility considerations. A 2024 white paper by the Electric Power Research Institute (EPRI) synthesizes several different data sources to depict geographic hot spots of data centers by type.[14] Multitenant or colocation data centers (those shared or leased by multiple organizations in the same physical location) guarantee extremely reliable service to their customers. A Tier I data center (the lowest tier) aims for 99.671% uptime, which translates to just 28.8 hours of downtime per year.[15] As such, multitenant data center providers plan and operate with minimal to no flexibility, aiming for as close as possible to a constant 100% load factor.

In contrast, data centers owned and operated by individual tech companies may have greater flexibility potential because they have fewer client-driven constraints. For example, Google is running a pilot to determine how best to participate in demand-response programs with its data centers.[16]

Cryptocurrency mining operations frequently operate flexibly because they are more price sensitive, but their participation in flexibility programs has drawn controversy due to payments from demand response exceeding revenue from their core business.[17] Mining operations can exacerbate emissions while also increasing local noise and air pollution.[18] Furthermore, in-depth analysis by the US Energy Information Administration concludes that there is major uncertainty surrounding the energy consumption of cryptocurrency mining,[19] making analysis of flexibility potential for this segment even more challenging.

Forecast uncertainty and flight risk

Load growth from data centers carries perhaps the highest forecast uncertainty of any relevant large end use today. Excitement surrounding generative AI is driving the current data center boom, but if long-term business models fail to turn a profit or if hardware and software advances moderate the amount of power demanded from the industry, data centers come with a risk of stranded assets and abandoned contracts. In the near term, however, there has been enough investment to develop a substantial number of new data centers, as already experienced in Northern Virginia.

A range of tariffs for large loads is emerging, including some explicitly for data centers, which can help mitigate forecast uncertainty and flight risk.[20] Tariffs that help mitigate uncertainty do so through mechanisms such as a contracted maximum demand, which is the maximum demand the load is allowed to reach under the contract and includes specified ramp times to reach that demand. See ***Actions regulators can take to improve forecasting*** (page 31) for more on tariff design and additional options to address these concerns.

Data centers have no strict land use requirements and therefore can be sited essentially anywhere with solid infrastructure (e.g., power, fiber, water, roads), which contributes to siting location uncertainty. However, some data centers may seek to colocate with generation to reduce transmission and distribution costs or emissions.[21] Data center companies often approach multiple utilities to negotiate the most favorable contract price and terms. In response, many states have created tax breaks for data centers as part of a broader economic development policy.[22] Although the long-term employment benefits provided by data centers are minor, personal property and real estate taxes on the equipment within them can create a tax windfall, especially in smaller economies.[23] These incentives initially made it simpler to predict where data centers might locate, but with headroom on existing grids now limited in primary markets, forecasting uncertainty will likely increase.

Many data center companies (e.g., Google, Amazon, Meta, and Microsoft) have voluntary climate pledges. This has encouraged them to seek tariffs and other novel arrangements that provide them with clean generation to cover their demand. For example, Google signed a clean transition tariff with NV Energy and Fervo,[24] and Microsoft signed a power purchase agreement with Constellation Energy to restart Three Mile Island.[25] Such agreements can include longer term lengths than traditional tariffs, providing utilities and asset owners greater confidence that their long-term investments will remain relevant.

Communication among states, improved zoning laws, and financial commitments from prospective data center developers can provide more certainty to load growth projections. Data centers remain subject to state and local commercial zoning laws. Therefore, cities and states can preferentially push them to brownfield and greyfield areas, which may be eligible for the Energy Infrastructure Reinvestment program,[26] thereby reducing the set of possible development locations.

Further reading

- For an exploration of present utility understanding and leading practices in addressing data center service requests, and integrating those requests into planning and operation processes, see ***Utility Experiences and Trends Regarding Data Centers: 2024 Survey***, EPRI, 2024.

Industrial loads and manufacturing

For the first time in a generation, manufacturing is returning to the United States rather than moving offshore.[27] This reshoring has been driven primarily by new industries that have sprung up in response to the clean energy transition and has been supercharged by Inflation Reduction Act incentives.[28] Because many industrial facilities operate large machines at high load factors, they hold opportunities to provide load flexibility and grid stabilization services.

Load shape and flexibility potential

Industrial loads often have the most “classic” load shape, following the shifts of workers. In other words, shifts staffed by more workers experience higher electrical demand. As the industrial sector electrifies, process heat requirements may keep load factors elevated outside of business hours. However, new industrial electrification technologies could provide ample opportunities for load flexibility.[29]

Such loads often display some flexibility, which helped make possible early utility demand-response programs. With the scope and value of demand-response programs expanding, utilities can continue to partner with industrial customers on demand-response programs, as their proven track record provides confidence in this resource. Furthermore, if green hydrogen becomes more established, it would offer a nearly ideal industrial process to participate in demand response due to its price sensitivity. Electricity contributes 50% to 70% of the levelized cost of hydrogen production.[30]

Forecast uncertainty and flight risk

Industrial customers tend to have low forecasting uncertainty because siting and permitting industrial facilities requires substantial time.[31] This generally means that once an industrial facility opens its doors, it is less likely to strand electrical infrastructure assets built on its behalf. Briefly, industrial sites generally require:

- Access to sufficient, correctly zoned land
- A location that can pass environmental reviews and receive community approval
- Supporting infrastructure for shipping raw materials and finished products (or the ability to create such infrastructure)
- A skilled local workforce
- Economic development tax credits
- Cheap electricity or economic development rates (which are often required for a project to turn a profit, for example, hydrogen production via electrolysis)
- High-capacity interconnections that often require distribution upgrades and sometimes require transmission upgrades

Given their price sensitivity, industrial customers may be able to strategically colocate near cheap clean resources if other requirements can be met. For example, the Evraz Rocky Mountain Steel mill in Colorado recently constructed an on-site solar facility to reduce net load.[32] Whereas historically most industrial processes have used fossil fuels to produce process heat, industrial heat pump technologies are beginning to mature, so seeking out cheap clean electricity could give industrials a competitive edge.

Load forecasting best practices

Prior to recent excitement surrounding large loads, a set of forecasting best practices had already been articulated. These best practices are now even more important for utilities to implement. Below is a summary of best practices from several resources.[33]

Employ scenario-based or stochastic load forecasting methods. When fewer end uses required electricity, both generation resources and loads were less weather dependent and less flexible, so that using a single deterministic forecast was sufficient. Long-term planning forecasts that drive investment decisions should consider multiple futures.

- Communicate load forecasts as ranges rather than single values. Taking a median scenario (or any single scenario) can obscure the value provided by stochastic methods, which are designed to encourage planners to consider a variety of risks, their likelihoods, and how they can affect load growth. Such ranges can better inform downstream modeling (e.g., resource adequacy studies) as well as allow regulators to view a more nuanced picture, which can help elucidate the difference between required, least-regrets, proactive, and imprudent investments.
- Attach reasonable probabilities to each scenario. Given the uncertainty and speculation surrounding large loads, utilities may choose to focus attention on a high load scenario and implicitly assign a higher probability to such a scenario. Planners should clearly communicate the likelihood of scenarios or ranges.
- Identify sources of load forecasting uncertainty. Not all uncertainty affects the forecast in the same way. For example, weather-related uncertainty may be accounted for in downstream resource adequacy modeling. On the other hand, a prospective data center customer that is still exploring siting across different utilities to identify the most favorable location represents a potential large step change in future load — and therefore could be treated via a scenario associated with a tailored probability.
- Incorporate scenarios that consider deviant policy and economic conditions. Although contingency planning can help hedge against unexpected events (e.g., the war in Ukraine), scenarios considering state and federal policy changes as well as economic cycles can help hedge against conditions that might be unlikely but would have a long-term impact.
- Include future climate data as well as historical weather data. This helps to capture a more complete — and therefore more realistic — distribution of future weather conditions (e.g., First Street Foundation's flood map projects much higher risk in Asheville, North Carolina, using future climate data than the Federal Emergency Management Agency's flood map, which uses historical data).[34]
- Employ long time horizons for planning forecasts to capture medium- and long-term trends (i.e., 10-plus years). However, recognize that forecast skill decreases further into the future.

Integrate end-use forecasting with econometric forecasting. Adoption patterns for both emerging and incumbent technologies will be more accurately forecasted with technology-specific models.[35] Models for individual end uses can ladder up to the area-wide stochastic planning forecast and may include their own stochastic elements. However, any hybrid methodology must protect against double counting, which could occur if adjustments are made for new load without accounting for their representation in econometric projections.

- Develop bottom-up 8760 load profiles for key end uses that have not reached market saturation or do not yet correlate with typical macroeconomic indicators. Whereas some incumbent end uses (e.g., residential refrigeration) have reached market saturation so that end-use modeling would not provide additional value, adoption and operation patterns of emergent end uses (e.g., EVs and heat pumps) carry substantial uncertainty. Furthermore, developing load profiles that track key large load customers (e.g., data centers or manufacturing facilities) can aid in retrospective analyses and offer a way to improve future forecasting assumptions.

- Perform separate forecasts for adoption, operation, and flexibility. Projecting adoption and operations for emergent end uses as well as large customers is commonplace at some utilities.[36] Forecasting flexibility more granularly and integrating such forecasts into downstream modeling practices (e.g., resource adequacy) remains an area for improvement.

- Incorporate newly available or underused data. Historically, regression algorithms provided a state-of-the-art forecasting tool for utilities. While regression still performs well in some applications today, AI algorithms may offer a better set of tools to capture complex trends in data and thereby improve forecast skill. This could allow utilities to leverage diverse data streams such as smart home device feeds, vehicle telematics, gas usage, weather reanalysis, local climate, customer propensity, and more to create differentiated forecasts for adoption, operation, and flexibility for a variety of end uses and large load customers.

- Track ongoing local adoption of various end uses to improve end-use models. Utilities can partner with smart home providers, VPP aggregators, large load customers, and local governments, which each hold a piece of puzzle depicting current adoption trends. Regulatory or policy action may aid in making such data available to utility planners.

- Seek direct customer input on forecasts. Particularly for large loads, including manufacturers, data centers, and EV fleets, additional engagement can lead to better outcomes on both sides. In addition, frequent input coupled with retrospective analyses can create a cycle of accountability between utilities and large load customers that may give regulators greater confidence in forecasts of these customers.

- Benchmark against third-party forecasts. Many independent organizations conduct end-use forecasts. For example, EPRI's EVs2Scale predicts adoption patterns for both light- and heavy-duty EVs,[37] and the National Renewable Energy Laboratory's ResStock and ComStock datasets provide end-use profiles for the US building stock.[38]

Ensure load forecasts are used consistently across different planning processes. Utilities should use consistent data and assumptions for load forecasts at all levels of planning — budget planning, distribution system planning, transmission planning, integrated resource planning, resource adequacy assessments, and contingency planning — or explain why and how their load forecasts differ. Although using a single forecast carries the benefits of internal consistency, it also exacerbates the impact of any forecast errors.

Further reading

- For an overview of and best practices associated with developing forecasts, including forecasting of utility load, energy efficiency, demand flexibility, building electrification, EVs, distributed solar, distributed battery storage, and utility costs, see **Developing Forecasts: Basics & Best Practices**, Lawrence Berkeley National Lab, 2023.

Case studies: Emerging practices for forecasting large loads

Although no utility's load forecasting process can serve as a model today, recent developments in locations where load forecasts have grown fastest hold important lessons. They also elucidate the role of regulatory staff, large load customers, and other intervenors in improving forecast accuracy. This section explores recent dockets from Dominion Energy in Virginia, Duke Energy in North Carolina, and Georgia Power.

Case study

Dominion Energy in Virginia Proceedings

General forecasting method

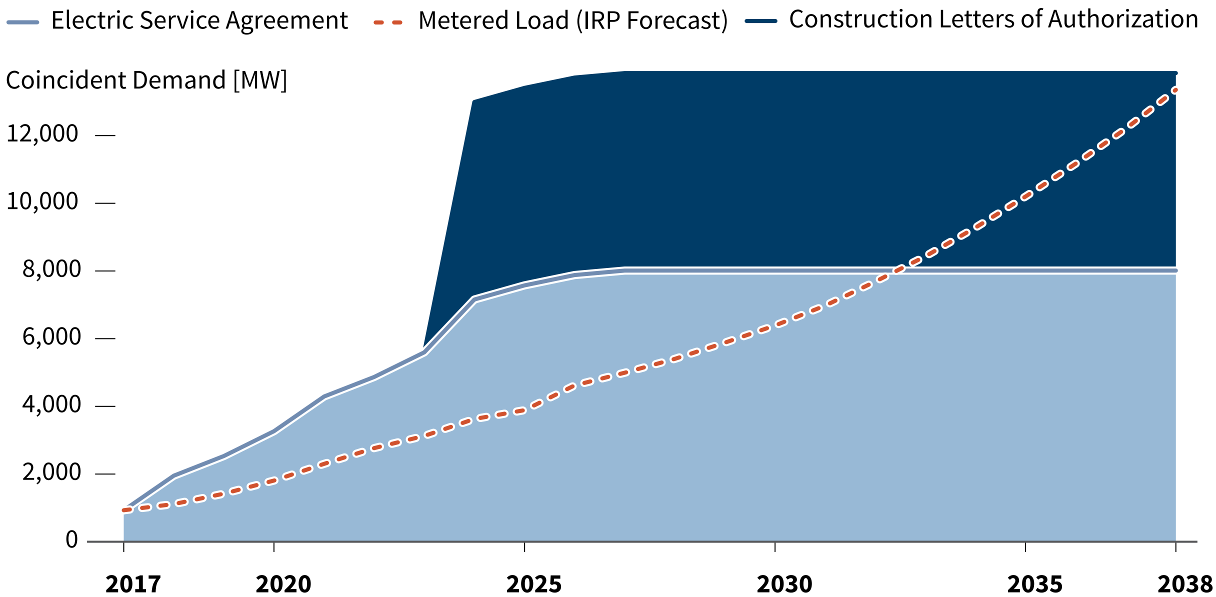
Dominion Energy uses an econometric approach to forecast sales, energy, and peak demand over a 15-year horizon.[39] The sales forecast produces monthly values by customer class, and breaks out estimates for heating load, cooling load, and non-weather-sensitive load. Appliance saturation and usage levels are dynamically adjusted in the residential forecast based on historical trends. The energy forecast is derived from the sales model using a simple regression that captures the historical relationship between monthly sales and energy consumption.

Historically adjusted hourly loads inform the hourly peak load forecast. This adjusted load excludes data centers but adds load offset by distributed solar generation and retail choice. The peak load forecast begins by predicting the non-weather-sensitive base demand; it then utilizes several weather variables — temperature, humidity, wind speed, cloud cover, and precipitation — to predict weather-sensitive demand. Additional variables capture variability on daily and seasonal time scales, and account for extreme or unusual events (e.g., hurricanes or the COVID-19 pandemic). Finally, adjustments for data centers, distributed resources, retail choice, and EVs are made at the end.

Data center forecast method

Dominion has made refinements to its data center load forecast over the years (see Exhibit 8). It first identifies the largest or fastest growing data center customers within its service territory — eight such customers in the most recent iteration — and then combines all remaining data center customers into an additional "customer." Second, it forecasts the load for each customer via statistical methods (i.e., linear regression) using a mix of public and confidential customer data. These customer forecasts are combined into an overall forecast, which represents the "high load" scenario. Dominion uses historical metered data to develop a statistical model of the data center industry, which it uses as its "low load" scenario. Finally, it averages the two scenarios to derive the "medium load" scenario, which it submits to PJM.

Exhibit 8 **Data center contracted capacity vs. metered coincident demand in Dominion Energy's service territory**



Note: Dominion did not review ESAs prior to 2018 and assumed ESAs were equal to actual demand in 2017. Actual ESA totals will be higher than this assumption.

RMI Graphic. Source: Dominion Energy, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/2024-irp-w_o-appendices.pdf

While Dominion's 2024 IRP is still under review by intervenors and the commission, its 2023 IRP update is instructive.[40] Virginia commission staff's consultants pointed out that load growth forecasts from PJM and Dominion were newly optimistic; forecasted data center load growth was higher than actual load growth for all of ERCOT.[41] Furthermore, a mere five companies made up 80% of the total projected data center growth through 2030. In other words, a slight shift in strategy by any of these companies could meaningfully alter realized demand in Dominion's territory. As a final note, the staff's consultants cautioned that forecasts should not only take into account future expected economic conditions but also seek to understand the rate of load realization (e.g., how much data center load is actually being built) versus forecasts.

Case study

Duke Energy in North Carolina Proceedings

General forecast method

Duke Energy's recent long-term load forecast was developed within its consolidated Carbon Plan and Integrated Resource Plan (CPIRP).[42] The forecast began with a service area–wide economic forecast from Moody's. Duke then produced an energy forecast using a statistically adjusted end-use model using key features, including income, electricity prices, industrial production indices, weather, and appliance saturation trends. Ex-post modifications to the forecast accounted for growth in EVs, rooftop solar, and energy efficiency programs. Finally, Duke derived summer and winter peak demand forecasts from the energy forecast.

Duke is also developing an integrated system and operations planning framework to enhance its load forecasting.[43] It includes Morecast, which is a 10-year hourly distribution system forecast focused on electrification, and third-party energy intensity forecasts. Currently, Morecast integration into IRP processes is still in development.

Large load forecast method

While economic growth is part of the baseline projection included in the economic forecast derived from Moody's, Duke manually applied an economic development adjustment for the first time in the 2023 CPIRP. This adjustment accounted for specific advanced-stage economic development projects in Duke's service areas absent in previous forecast cycles (e.g., data centers). To avoid double counting these projects with growth predicted by the econometric model, Duke reduced the projected load expectation on a by-project basis, typically by 30% to 60%.

According to testimony accompanying the CPIRP,[44] two main criteria were used to identify projects for the economic development adjustment: (1) either a prospective large load customer had already executed an agreement indicating an intention to obtain service from Duke or one was in an advanced stage of engagement toward that end, or (2) a prospective large load customer had begun physical development activities within Duke's territory (e.g., obtaining land, initiating rezoning of land). For the spring 2023 load forecast used in the initial 2023 CPIRP, Duke identified eight economic development projects. By the fall 2023 update, an additional 27 projects met the criteria. Given this rapid explosion of prospective projects, Duke developed an additional economic development load forecast for fall 2023 that included other known large projects that had yet to make material commitments.

The North Carolina Utilities Commission approved a stipulated agreement between Duke and other parties, which placed additional requirements on Duke's load forecasting practices.[45] In the stipulation, Duke agreed to monitor economic development and the large load pipeline and update the commission on its findings semiannually. Methodologically, the stipulation requires further discussion on predictive methods around uncertainty, greater consideration of distributed energy resources through customer programs and Grid Edge (a building energy efficiency management software), and consideration of grid-enhancing technologies.

Case study

Georgia Power

General forecast method

Georgia Power engages in full IRP proceedings every three years. A 2023 IRP update was approved in April 2024,[46] but the baseline forecasts associated with the 2022 IRP are the most recent general forecasts.

Georgia Power performs short- and long-term forecasts for both energy sales and peak load. At a high level, the short-term forecasts are econometric, feeding economic and demographic variables into a regression-based model. Historical weather data between 1980 and 2020 is averaged to define a normal weather year for forecasting, which neglects historical extremes and does not reflect the potential for different, more extreme future weather.

The long-term forecast has a 20-year horizon, driven by the IRP statute. The long-term forecast employs end-use models (LoadMAP from Applied Energy Group), which predict the uptake of various technologies and generate long-term forecasts by customer class. Finally, the resulting short- and long-term models are combined to produce the final forecast, with the short-term forecast used for the next 3 years and the long-term forecast used for the remainder of the 20-year period.

Large load forecast method

Georgia Power also forecasts rapid load growth, primarily from data centers and clean manufacturing. In its 2023 IRP update, the company significantly adjusted its forecast from its 2022 IRP due to the potential for large load additions. As part of this update, it established a methodology for integrating known project inputs into its forecast. Although Georgia Power had incorporated large loads in its forecast for prior plans to account for known large industrial projects, its 2023 IRP update filing represented a significant expansion of this process.[47]

Intervenors highlighted several opportunities for improving Georgia Power's large load forecast:

- Strengthening the commitment requirements for loads to be included in the forecast: Microsoft, in intervenor testimony, pointed out that that Georgia Power is unique among its peers in including large projects that have yet to select a location and a service provider, which could lead to overestimates of new large loads.[48]

- Using a broader range of forecasts in modeling: Microsoft and several other intervenors commented that the use of the P95 load forecast (representing the 95th percentile load forecast produced by Monte Carlo simulations) may be reasonable for a high-growth scenario, but not as the only forecast used for modeling in the 2023 IRP update.

- Increasing transparency: The commission's Public Interest Advocacy Staff commented that greater transparency is necessary — especially into ramp rate and load materialization assumptions — to determine the quality of the large load forecast. Additionally, some intervenors commented that confidentiality of prospective loads in the economic development pipeline shifts risk away from companies that may drop out of the pipeline with few consequences.

Although the Georgia Public Service Commission ultimately approved the forecast in the IRP update, it included a caveat that the approval does not constitute approval of the methodology used to create the load forecast. Furthermore, it directed Georgia Power to file quarterly large load updates to aid in the 2025 IRP.[49]

Georgia Power now files quarterly updates on its load forecast, including its economic development pipeline. These pipeline updates include:

- The total pipeline size

- Any changes in the pipeline from the previous quarter (e.g., projects entering or exiting the pipeline, construction updates, and new load announcements)

- Projected load ramp-up schedules

- Individual project information (e.g., customer class and market segment)

As of September 2024, the full economic development pipeline stood at 36.5 GW through the mid-2030s.[50] Information from this economic development pipeline is expected to flow into Georgia Power's load realization model, one component of its long-term load forecast process.

Actions regulators can take to improve forecasting

Regulators can play three critical roles with respect to forecasts: (1) establish guidelines for forecasting, (2) review and approve utility forecasts, and (3) approve or deny cost recovery for investments made based on forecasts. Although utilities are ultimately responsible for developing the forecasts, regulators can influence the quality and applicability of forecasts across different venues. While no forecast is perfectly accurate, ideally, forecasting processes are useful in guiding consequential regulatory decisions.

Regulators across both restructured and vertically integrated markets can focus on three goals to support more useful forecasting practices in the face of the challenges presented by large new loads (see Exhibit 9).

Exhibit 9 Goals for modernizing forecasts to integrate large loads

Challenges with load forecasts today	Goals for load forecasts
Limited: Load forecasts may not include the relevant characteristics of large loads.	**Thorough:** Ensure load forecasts accurately reflect the unique characteristics of large loads to their best ability.
Outdated: Load forecasts that are updated annually do not match the current pace of change.	**Up-to-date:** Increase the frequency of updating both load forecasts and load forecasting processes.
Opaque: Load forecasts can rely on inaccessible data, making bias tracking infeasible.	**Validated:** Make load forecast data and processes visible to other stakeholders and create opportunities for accountability.

RMI Graphic

The following subsection explores each of these goals and provides specific actions regulators can take to advance these goals for load forecasts (see Exhibit 10). The goals and actions were informed by discussions with regulators, industry experts, and RMI staff in the second **Reg Lab cohort**. We hope that by providing a menu of options to choose from or build on, states can more comprehensively improve load forecasting to meet today's challenges.

Exhibit 10 Actions for regulators

Goals for load forecasts	Actions regulators can take
Thorough	• Increase commission and utility understanding of new loads by initiating technical conferences or investigatory proceedings or by engaging informally with stakeholders. • Revise planning guidelines to incorporate emerging forecasting practices for new loads, such as establishing a separate large load forecast and processes to avoid double counting (see *Appendix: Discovery questions for load forecasting*). • Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads.
Up-to-date	• Require more frequent reporting of long-term load forecasts, such as quarterly. • Iterate forecasting processes as new practices and end uses emerge so that forecasts remain current.
Validated	• Encourage utilities to leverage transparent external data and forecasting tools where possible so that stakeholders and the commission can play an active role in vetting assumptions. • Make forecasts and actuals accessible and learn from past forecasts to assess past forecast accuracy and identify sources of error. • Explore monetary incentives or penalties for forecasts based on accuracy, including tariffs that shift risk to the specific large customers driving load growth or to the utility.

RMI Graphic

GOAL
Through

Ensure load forecasts accurately reflect the unique characteristics of new load drivers

Understanding and integrating the unique characteristics of new load drivers and modernizing forecasting processes can reduce unnecessary inaccuracy in load forecasts. Emerging large loads have unique characteristics that distinguish them from past end uses and from one another. Forecasts that are blind to characteristics including flexibility potential and flight risk will not reflect the needs of the future grid.

Options for regulators

Increase commission and utility understanding of new loads and their characteristics: Regulators can proactively learn about potential large load drivers in their state to better understand and evaluate forthcoming utility forecasts and other proposals, such as new tariffs. In addition to attending conferences, regulators can launch their own investigatory proceedings, technical conferences, or informal learning calls to increase their understanding of new loads specific to their state context. For example, the Minnesota Public Utilities Commission focused its external planning meeting in late 2024 on data center development in the state, with presentations and questions and answers from data center representatives, system planners, state agencies, and other stakeholders.[51] Similarly, when faced with challenges, including the impact of new loads on the electric system, the Maryland Public Service Commission initiated a technical conference on resource adequacy, with policymakers, experts, and other industry stakeholders providing specific recommendations.[52]

Revise planning guidelines to incorporate emerging forecasting practices for large loads: Regulators can set expectations or update guidelines for how utilities include new large loads in forecasts. Depending on where utilities are in their planning cycle, regulators can proactively set guidance by revising and updating planning rules or issuing orders on a previously filed plan or rate case to require future forecasting improvements. Guidelines could include one or more of the best practices described in the ***Load forecasting best practices*** section of this report.

Such new guidelines can better capture the characteristics of potential large loads. For example, regulators can request that load forecasts include the time each large load is expected to take to ramp up to contracted capacity, each load's flexibility characteristics, and the probability each will be built. Georgia commission staff took early steps and required the utility to file quarterly large load updates, which included the project status and expected ramp up period for each potential load.[53] Georgia Power's load forecasting process is discussed in detail in ***Case study: Georgia Power***.

In addition, regulators may need to update load forecasting practices to prevent double counting. If utilities create a separate large load forecast, regulators can request that utilities deconflict their large load forecast and their base economic forecast. Regulators can set expectations or ask detailed discovery questions to ensure that utilities discount econometric forecasts to account for large loads showing up in dedicated forecasts (see ***Appendix: Discovery questions for load forecasting***). For example, the State of North Carolina Utilities Commission directed Duke to monitor economic development and discount expectations of large load projects to avoid double counting of these loads and to explicitly account for such uncertainty as project delays, cancelations, and other factors outside Duke's control.[54]

Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads: Regulators can proactively coordinate with other state agencies and neighboring states to understand the current fiscal and legal environments that may affect data centers and other large loads. As of early 2025, more than 60% of states had established tax incentives to encourage data centers to build within their state.[55] Understanding these incentives and other state policy decisions can enable regulators to ask more informed questions of future load owners and utilities when reviewing load forecasts. For example, if a state has proposed or recently passed legislation that encourages or discourages development, regulators can inquire if and how utilities have integrated these changes in their forecasts of large loads.

Regulators can also encourage utilities to investigate whether prospective large loads are considering locations both in and outside of the state and reflect this "shopping around" in how individual large loads are represented in the forecast.

GOAL
Up-to-date

Increase the frequency of both updating load forecasts and updating load forecasting processes

Outdated forecasts and forecasting processes are less adept at managing uncertainty and lead to less accurate forecasting. When load forecasts display high uncertainty and have the potential to rapidly change with the addition or removal of predicted large loads, updating forecasts every one to three years in an IRP is too infrequent. Similarly, the tools and processes for forecasting large loads are rapidly evolving as new information and best practices emerge.

Options for regulators

Require more frequent reporting of long-term load forecasts: Regulators can help ensure utilities have a process for collecting and updating information about large load requests as part of forecasting that is ongoing between planning cycles. Today, especially with large loads, regulators can provide guidance for how often forecasts should be updated outside of the typical planning cycle. For example, in recognition of the unprecedented load growth, the State of North Carolina Utilities Commission requires Duke to report semiannually on economic development and the pipeline of large load projects.[56]

As processes continue to evolve, regulators can consider requiring even more frequent reporting, such as up-to-date, publicly available online dashboards that could be accessed similar to generation interconnection queues in some geographies (e.g., Interconnection.fyi).[57] Such dashboards would allow all interested parties to see when updates to the forecast are made and how specific projects affect the forecast, and allow third-party verification, streamlining the ability of stakeholders to comment on forecasts in dockets.

Iterate forecasting processes as new practices and end uses emerge: Load forecasting tools and processes are emerging as the industry learns more about new load drivers. Regulators can learn from other states to understand what forecasting practices leading utilities are adopting and launch investigatory proceedings that focus on forecasting best practices.

GOAL
Validated

Make load forecast data and processes visible to other stakeholders and create opportunities for accountability

Increasing the transparency of load forecasting processes and incorporating more accountability for forecasts can increase the validation of load forecasts, even when accuracy is impossible because of uncertainty. Similarly, making trends in past forecasts available can allow utilities, regulators, and other stakeholders to learn from them and can ensure utilities are iterating their approach accordingly.

Options for regulators

Encourage utilities to leverage transparent external data and forecasting tools where possible:
To ensure forecast assumptions are unbiased, regulators can encourage utilities to use trusted third-party

data and tools when developing load forecasts for specific load types. Alternately, regulators can explore enabling or requiring that an independent entity, such as the state energy office or a university, produce load forecasts. For example, the California Energy Commission prepares and updates detailed forecasts of both electricity and gas consumption as well as peak demand over a 12-year timeframe.[58] Additionally, regulators can encourage utilities to update internal forecasting tools or adopt external tools (e.g., GridUp for EV load forecasting[59]) to more comprehensively and consistently forecast new end uses. At the time of publication, a national dataset that tracks large loads does not exist. Such data should be available to regulators and intervenors in any proceeding where a load forecast is implicated.

Make forecasts and actuals accessible and learn from past forecasts: Regulators and utilities can use past forecasts to improve forecasting. Requiring "backtesting" of forecasts to assess their accuracy could help utility forecasters and other stakeholders evaluate what kind of forecasting errors led to which planning decisions and identify opportunities to improve forecasting going forward. Regulators could require backtesting as a component of existing resource planning practices for vertically integrated utilities or create a docket dedicated to understanding historical load forecasting. Puget Sound Energy's 2021 IRP provides an example of backtesting: the utility included a retrospective analysis of how its five previous demand forecasts compared with reality for several key variables, identified explanations for the deviations, and integrated the lessons into the current load forecast.[60]

For large load forecasts specifically, regulators could require utilities to track and report the number of large loads that fall out of each stage of the pipeline for each type of load. With this tracking, utilities and states could develop a greater understanding of the timeline and likelihood of different types of large loads, which can then be incorporated into forecasting. If such data is published in an easily accessible format, then third parties and other regions would be able to use this data as well.

In restructured states, load forecasters within regional transmission organizations can publish each load source's contributions to individual utility forecasts, which could help address issues of double counting prospective loads among utilities. For example, PJM's Load Analysis Subcommittee publishes summary reports that include a breakdown by utility.[61]

Explore monetary incentives or penalties for forecast accuracy: Given the stakes of over- or under-forecasting, regulators could establish financial incentives or penalties for the forecasting practices or the forecasts themselves to shift risk from all customers to either large load customers or the utility itself. Requiring certain contractual agreements (e.g., tariffs, charges) can shift a portion of forecasting risk away from all customers and incentivize more accurate forecasts from large load drivers. For example, the Oregon Public Utilities Commission established two new charges that apply to customers requiring greater than 50 kilowatts: a capacity reserve charge, which is a price per kilowatt for any unused capacity outside of a 10% load forecast buffer, and an excess demand charge, which shares the risk of underestimating load requirements.[62]

To combat the natural incentive for cost-of-service utilities to over-forecast, regulators can increase utility interest in more conservative forecasting and investment strategies. One option is for regulators to require that the utility demonstrate prospective large loads have hit specific milestones of certainty before granting a Certificate of Public Convenience and Necessity. If the utility chooses to build generation before securing the predetermined level of load certainty, regulators could provide partial cost recovery for the investments made for this load.

Although not specific to load forecasting, the Business Plan Incentive in Great Britain is another example of how regulators have created an incentive for the utility to be a good steward of a specific process. In this example, the regulator instituted a Business Plan Incentive that provides a reward or penalty based on the completeness and the quality of each utility's business plan submission.[63,ii] The regulator recognized that incomplete or poor plans impeded its desired cost-effectiveness outcome and developed evaluation criteria, a process, and the incentive cap accordingly. In the United States, regulators could explore a similar mechanism to incentivize complete and quality load forecasts.

ii Business plans in Great Britian are similar to multiyear rate plans in the United States, though they are broader and include grid planning, among other things.

Making investment decisions under forecast uncertainty

Even when best practices are adopted, all forecasts remain uncertain. However, with rapid load growth upon us, utilities and commissions must be able to make decisions despite significant forecast uncertainty. Decision-making frameworks can include the following:

Prioritize "least-regrets" capital investments: Determining what constitutes a least-regret investment is a departure for regulators from more traditional least-cost decision-making. Least-regrets solutions in the face of uncertainty will be fast, affordable, and flexible. Many underrepresented options in utility portfolios meet these criteria and are focused on leveraging existing infrastructure, including energy efficiency, VPPs, grid-enhancing technologies, reconductoring, and clean repowering.[64]

In addition to solutions that are fast, affordable, and flexible, least-regrets options may also be characterized as options that are robust across a range of possible future scenarios.[65] The field of decision-making under deep uncertainty has studied such robust approaches, and water resource planners have applied them at scale.[66] Regional and interregional transmission, although higher in up-front capital costs than the other least-regrets options described here and slow to deploy, may be one such robust solution. Transmission can alleviate congestion costs and provide access to geographically distributed clean resources over the long term. US regulators can also compare individual infrastructure investments or investment levels against those of international peers, some of whom may be further along in the energy transition (e.g., Great Britain).[67]

Distribution system investments are another example of a potential least-regrets solution that provides value across many possible future scenarios. Distribution system planning is often reactive, but proactive investment can increase options for nimbly navigating load growth. Regulators can work with utilities to determine which upgrades will be relevant and prioritize those that will be useful in many load growth futures.

For example, in response to a staff proposal, the California Public Utilities Commission issued a proposed decision that sets detailed expectations for forecasting practices.[68] The decision includes using scenario planning to improve forecasting and disaggregation in distribution planning process, and implementing a pending loads category. The commission acknowledged the additional work required for both, and outlined plans for stakeholder engagement to finalize the details of how each of these would be implemented. While these proposals target distribution-level grid impacts, similar efforts could manage uncertainty at the bulk power system level.

Use tariff design or other contractual commitments to allocate risk and shore up uncertainty: Through tariffs, utilities can require up-front payments, or collateral, from large load customers to pay reservation fees for the generation and distribution infrastructure that their projected load will require. Tariffs can also have clauses that require data centers or other loads with flight risk potential to pay a fee if the load does not materialize as expected or vacates before a certain number of years. Separating the risk of serving some large loads from the rate base can protect ratepayers. Increased certainty for large load requests helps grid planners with load forecasting and transmission planning. Regulators can and should provide guidance on and oversee tariff design for large load interconnection.

The Indiana & Michigan Power Modification to Industrial Power Tariff provides an example of a structure that requires commitment to pay from large loads to reduce risk. Large load customers on this tariff must pay an exit fee if capacity is ever reduced by more than 20%, and the minimum demand charge is increased from 60% to 90%.[69] Further, companies must pay a collateral payment, recalculated annually, equal to at least 24 times their maximum expected monthly non-fuel bill, further putting the risk onto the large load customer instead of the utility.

Another example is the October 2024 AEP Ohio settlement.[70] Under this settlement, any new data center larger than 25 megawatts (MW) would have to pay at least 85% of the energy it expects to use each month. This monthly basis of pay protects against concerns of uncertain timelines as well as total load. Data centers must also pay an exit fee if projects are canceled or obligations in contracts are not met.

Even more directly, the Georgia Public Service Commission approved a rule where large loads (above 100 MW) are billed based on risk.[71] Data centers are required to pay any transmission and distribution costs that their generation requires, protecting other customers from unexpected costs.

Encouraging data centers to build new clean generation colocated with load centers can alleviate some concerns about uncertainty as well. It could incentivize them to rightsize their load projections and prevent the need to consider the data center in transmission, distribution, and capacity planning.[72]

Conclusion

This report highlights several opportunities and emerging practices for utilities and grid operators to improve the representation of large loads in their forecasts. It also features a set of load forecasting best practices that utilities and grid operators can apply today to improve forecasts regardless of the size and scale of projected load. Although large load forecasting practices are still emerging, case studies from jurisdictions projecting some of the fastest growth (Duke Energy, Dominion Energy, and Georgia Power) point toward changes needed.

Regulators also have a critical role to play in mitigating the affordability and reliability risks at stake. There are actions they can take to ensure that forecasts are more thorough, frequent, and validated. There are also complementary approaches they can take to update decision-making frameworks and navigate the remaining uncertainty, such as prioritizing least-regrets investments and adopting tariffs or other financial structures that shift risk and increase the commitment of large loads.

Additional research on large loads and their characteristics is needed to support improving forecasting. Utility planners also need standard datasets that describe load shapes, flexibility, ramp rates, and the probability of load realization for different load types. More experience is needed to inform best practices for adjusting econometric forecasts to account for large loads. New, creative approaches beyond econometric forecasting would further reduce forecast errors.

Even though all forecasts are wrong, the scale of projected load growth and its associated risks creates an imperative to ensure that forecasts remain useful in guiding consequential regulatory decisions.

Appendix: Discovery questions for load forecasting

Following are what commissions can ask a utility to ensure robust forecasting practices in the face of significant load growth.

Assumptions: Please provide a detailed description of the core components of the load forecast, including, at a minimum, projections for EVs, building electrification, population growth, VPPs, green tariffs, demand response (including time varying rates), behind-the-meter generation, and energy efficiency. Separately, please identify and justify the forecast for adoption/ownership, operation, and flexibility potential, including your assumptions about rates, controls, and other signals available to shape load. Additionally:

- For each of the core components, which methodology was used to develop the forecast?
- What were the assumptions for how core components contribute to local and aggregate peak demand? What battery backup or on-site generation assumptions were made related to large industrial loads?
- For VPPs, demand response, and energy efficiency, please provide both the energy and demand savings.
- Please describe how VPPs and demand response were modeled (e.g., as dispatchable resources or captured as reductions in the load forecast).
- Please provide documentation of your inputs with citations.

Load certainty: For industrial and data center loads, please rate the existing contracting certainty from (1) extremely prospective load to (5) extremely certain load. Explain why each load received its assigned rating. If loads were divided into specific categories (e.g., technical review, request for service), how was each category defined? Additionally:

- In a table format with each project as a row, please provide detailed updates by project, including those with delays or that were canceled. Include if contracts have been signed and if projects have broken ground.
- Please describe in detail the steps that the utility took to evaluate ramp-ups for each large load project in the forecast. Include when the utility expects contracted load to appear and reach specific levels of operation and what drives those assumptions.
- Please provide expected milestones and commitments from large load developers. If this is not the first time this kind of large load driver has appeared in the utility service territory, please include any successes or failures that the load driver has had meeting past commitments and expectations.
- For any large loads that have changed levels of certainty between the previous iteration and now, please describe which criteria led to the recategorization to a lower certainty or a greater certainty.

- Please document and share any communication the utility had with large load representatives that informs the evaluation of the large loads' likelihood to materialize.

- Please explain the customer deposit required, on a per MW basis, to attain an energy service agreement and whether the customer met previous contracting milestones.

- Please verify that energy service agreements are designed to recover all costs to the utility if a project is canceled.

Load flexibility: For industrial and data center loads, please provide information on how these loads will participate in energy efficiency and demand-response programs, including any contractual requirements or other mechanisms for ensuring participation.

- Please explain how existing or proposed energy efficiency and demand-response programs encourage large load participation. For existing programs, please include what fraction of large loads has enrolled in each energy efficiency and demand-response program, what challenges have hampered greater participation of large loads in each program, and any steps the utility intends to take to increase participation.

- For each industrial and data center load, please describe any planned backup generation. Please include details on how the customer will provide the utility with visibility into operation of the backup generation, and how the utility intends to account for the presence of the backup generation in planning.

Scenarios: Please describe in detail which scenarios the utility developed to inform this load forecast? Please include: key assumptions, how the utility determined the upper and lower bound scenarios, and how the utility will use these scenarios to inform an investment plan.

Retrospective analyses: Please provide a quantitative and qualitative analysis of how the past five load forecasts compare with actual outcomes for sales, energy consumption, and peak demand. Provide hypotheses or explanations for any deviations. Finally, please describe how the utility is addressing the source of those deviations in the current forecasts.

Bill impacts: Please describe how cost allocation of the predicted load and associated generation, transmission, and distribution investment will affect each customer class.

Clean commitments: Please document in a table which data center and industrial loads have made any public clean energy commitments. For each line, include if these entities have followed through on clean energy commitments in your territory. Please explain in detail how the utility will account for commitments to procure clean energy made by large load customers in planning.

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RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

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ENERGY FUTURES GROUP

Review of Large Load Tariffs to Identify Safeguards and Protections for Existing Ratepayers

By: Stacy Sherwood

On behalf of Earthjustice

Final Version

January 28, 2025

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Introduction

Cloud computing, artificial intelligence ("AI"), and cryptomining have resulted in an unprecedented projected growth in power demand throughout the nation, and many forecasts find that such demand will continue to grow significantly over the next decade. In its February 2024 analysis, EIA estimated that cryptocurrency mining in the U.S. may represent up to 2.3% of the annual total U.S. electricity demand.[1] Between May and August of 2024, there were predictions that data centers alone could reach as much as 7.5-9% of the United States' total electricity consumption by 2030.[2] [3] Due to the size and frequency of requests, forecasted load related to data centers and cryptomining are ever changing evolving and can change every few months.

The increase in power demand for data centers and other large consumption activities can negatively impact existing customers on the electric system and limit or eliminate progress on renewable energy and greenhouse gas emissions goals.[4] Negative impacts can include increased electricity demand that cannot be met with current capacity and increased congestion, a new customer's operations ceasing after a utility's significant investment in distribution and/or transmission infrastructure and procurement of new capacity. These translate into increased and abandoned costs left to be recovered from existing ratepayers.

For data centers, the full operating capacity does not typically occur for the first few years of a utility service contract, which impacts the timing of cost recovery and cash flow from servicing the load for the utility. Therefore, it's pertinent to include safeguard provisions in tariffs and special contracts to protect ratepayers and environmental goals, such as ensuring the facility is paying its fair share of transmission and distribution costs associated with service, requiring a certain number of jobs for economic development rates, and meeting decarbonization plans and goals of both the host jurisdiction and the host utility.

This report consists of four sections. The first section briefly considers why technology giants, such as Microsoft and Amazon, have an interest in designing their own contracts related to data centers and clean energy procurement. Second, this report summarizes a review of high-density tariffs and special contracts established for large load customers. Through this review, common provisions were identified, as well as details on how certain provisions can serve as

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[4] Although some may use the terms data center and cryptomining facility interchangeably, there is a distinction between the two, particularly when it comes to operation. Cryptomining facilities operate depending on the price signal from the crypto markets, with facilities operating up to 24 hours a day depending on the financials. Data centers have high load factors and operate on a 24/7 basis.

safeguards for ratepayers and/or environmental goals. The third section identifies ongoing proceedings and efforts to monitor as they could have a significant impact on the structure of high-density tariffs in the future. The final section of this report discusses certain safeguards more in-depth and identifies specific language for consideration in future tariffs and special contracts to serve as safeguards for ratepayers.

With the evolving market surrounding the electric service of data centers and large loads, it should be noted that this report was drafted based upon the information available throughout the latter half of 2024. The cases summarized in the third section of this report are based upon the information available at the time and will not include all details of the case, such as settlement proposals and commission orders. For clarity, in this document, a reference to a data center or cryptocurrency mining customer that the tariff would be applicable to will be identified as "customer," the utility will be referred to either as "utility" or "company," and those already on the power system will be referred to as "ratepayers."

Tech Giants' Interest

Technology giants, such as Amazon, Google, Microsoft, and Meta, all have significant stakes in locating and developing their data centers to support cloud computing and artificial intelligence. In addition to trying to develop a competitive edge in the data center world, each organization has corporate goals related to clean energy. Additionally, the technology giants may also have policies related to the implementation of their data centers. For example, requirements for onsite backup power. Price signals in the market help the companies determine which types of onsite power back up is procured (storage versus fossil fuel generators).

Corporations pursuing data centers may be proactively working with utilities on tariff development to find ways to reduce costs around onsite generation back up, energy costs, and achieving renewable energy goals. If a corporation is working with a utility to develop a tariff, the corporation can ensure the tariff supports its efforts to develop a competitive edge, while achieving corporate goals and requirements for siting data centers.

Review of Existing Tariffs and Special Contracts

A multitude of tariffs and special contracts were reviewed, from which a total of ten tariffs, each from a different state, were identified as being models for consideration based upon the safeguards included in the tariff language.[5] Regardless of the location, there are common rate structure elements, including:

- Contract length, requirements for investment by the new customer, and cost assignment.
- Demand, load factor, and power factor.
- Requirements to shed load and/or participate in demand response.

[5] A detailed summary of the reviewed tariffs and special contracts are provided in Appendix A of this report.

- Resource adequacy and requirements related to renewable or clean energy.

There is not one perfect tariff design that can adequately address the potential concerns related to large loads, and it is likely that large load tariffs will have to evolve over time, as loads and customers' requirements continue to change. However, there are elements of a rate structure that can serve as safeguards for existing ratepayers, ensure new customers pay their fair share of system costs, promote more efficient electricity usage, and minimize adverse impacts to clean energy and climate goals.

Figure 1 below provides the prevalence of safeguard provisions throughout the ten tariffs examined. A more detailed review of each of the requirements is provided in Appendix A, along with a link to the tariff or special contract. A green circle indicates that a safeguard is included as part of the tariff, while a red circle indicates that it is not a tariff requirement. If the circle is white, then it is considered not applicable, either because it was not mentioned, or in the case of demand response, it is not offered by the utility. As noted below, not one of the tariffs includes all the safeguard provisions discussed in this report. That is because safeguards are dependent upon a service territory's needs, which could pertain to ensuring the customer base does not suffer from stranded asset costs or to capacity and transmission constraints. For example, if there is excess capacity in a service territory, stakeholders may not be as concerned with having a robust demand response program or interruptible tariff.

Figure 8 Safeguards Included in Data Center and Cryptocurrency Tariffs

State	Utility	Document Type	Contract Length	Minimum Demand	Minimum Load Factors	Range for Power Factor	Requirements for Investment	Cost Assignment	Requirement to Shed Load	Load Subject to Interruptible Service	Maximum Hours of Interruptible Per Year	Demand Response
WY	Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy	SC	🟢	🟢	○	○	🟢	🟢	🟢	🟢	🟢	🟠
AR	Entergy Arkansas LLC	T	○	○	○	○	🟢	🟢	🟢	🟢	🟢	○
ID	Idaho Power Company	T	🟢	🟢	○	🟢	🟢	○	🟢	🟢	🟢	🟠
NY	New York Municipal Power Agency	T	○	🟢	○	○	🟢	🟢	🟠	○	○	○
SD	Montana-Dakota Utilities Company	T	🟢	🟢	🟢	🟢	🟠	🟠	🟢	🟢	🟢	🟢
WA	Grant County Public Utility District	T	🟠	🟠	○	○	🟠	🟠	🟠	○	○	🟢
IN	Indiana Michigan Power	T	🟠	🟢	○	○	🟢	○	🟠	○	○	🟠
KY	Kentucky Power	SC	🟢	🟢	○	○	○	○	🟠	🟢	🟢	🟢
MO	Evergy Missouri Metro	T	🟢	🟢	○	○	○	🟢	🟠	○	○	🟢
ND	Montana-Dakota Utilities Company	T	🟢	🟢	🟢	🟢	🟠	🟠	🟢	🟢	🟢	🟢

Note: For document type, “T” indicates a tariff and “SC” indicates a special contract.

Below is a more in-depth discussion of the safeguards in existing contracts and how they could be applied to future contracts for large loads.

Contract and Minimum Demand

The most prevalent safeguards include establishing a contract term length and minimum monthly demand to qualify for the tariff. The latter is a typical element of a commercial or industrial rate structure. This allows for targeting certain, or significant, energy loads. By establishing a monthly demand minimum for participation, the tariff can allow smaller load customers to receive service through another tariff, where the associated risks are not as significant. Minimum demand should be determined:

- in relation to the overall demand from the commercial and industrial customers and sector,
- in relation to the overall service territory's demand; and,
- through consideration of the available capacity in the system and the need for additional capacity builds.

Not only can demand serve as a minimum requirement for a tariff, but there can also be a demand threshold that requires customers above a certain level of demand to have a special contract. This can be useful in large load scenarios as it will allow for the utility to ensure safeguards are in place for existing ratepayers, the Company, and the customer.

> Caution: The tariff should indicate if the minimum demand is based upon the location, service point, or customer. There is potential for customers to find ways to avoid paying the tariff by structuring the demand in a manner that stays below the minimum demand threshold, such has having multiple meter points for a single customer

Idaho Power Company's Speculative High-Density Load tariff is offered to those with metered usage exceeding 2,000 kilowatt hours ("kWh") for at least three billing periods and requires customers with a minimum demand threshold of 1,000 kilowatts ("kW") to be served under this tariff. The tariff specifies that a special contract is required for loads over 20,000 kW.[6] The tariff language is provided below.

SCHEDULE 20
SPECULATIVE HIGH-DENSITY LOAD

If the aggregate power requirement of a Customer who receives service at one or more Points of Delivery on the same Premises exceeds 20,000 kW, the Customer is ineligible for service under this schedule and is required to make special contract arrangements with the Company.

Service under this schedule is applicable to electric service supplied to a Customer at one Point of Delivery and measured through one meter delivered at the primary or transmission service level. This schedule is applicable to Customers whose metered energy usage exceeds 2,000 kWh per Billing Period for a minimum of three Billing Periods during the most recent 12 consecutive Billing Periods. Where the

[6] Idaho Power Schedule 20 Speculative High-Density Load: https://docs.idahopower.com/pdfs/AboutUs/RatesRegulatory/Tariffs/20.pdf.

The contract term length is not related to the offering of the tariff; rather, this is a feature of the special customer service agreement. There are various lengths used by utilities and are likely dependent upon risk associated with the customer's service load. Of the arrangements reviewed, contract terms varied from two to ten years. In addition to the overall contract, some utilities required terms for renegotiation and/or pricing terms. Longer-term contracts, such as contracts of ten years or more, may have a shorter term related to pricing, as that is harder to accurately forecast over an extended period. Most of the contracts had contract length options within the three- to five-year span. This allows for limited forecasting on price and can accommodate ramp up in load, while also allowing for cost recovery of improvements to the system.

Some large load tariffs, such as those for facilities with a load greater than 50 MW, are proposing longer contract terms, such as 20-year minimums, with termination of the contract only if the facility ceases operation along with a penalty payment.[7] Large loads, like those more than 100 MW, will require significant investment in the electric system, both in capacity and the transmission system. Investments of that size are riskier given the level of cost recovery, depreciation of assets, the need for large capacity resource builds, and the fact that the significant load increased will be limited to one customer class rather than spread across multiple customer segments. The benefit of a longer contract term for this size of customer is that the cost recovery of the investment can be spread over the contract term. This will also allow for cost allocation that enables these customers to pay for their share of the utility investment needed to provide them with electric service. A negative of a long contract term, particularly if there is not much diversity in the customer class, is that an economic downturn or changes in the industry could significantly impact the load and need for service. For example, if the industrial customer class primarily consists of cryptocurrency mining customers, then a decrease in proof-of-work cryptocurrency value could limit the utility's revenue from that class. Therefore, it is important to develop a guardrail to alleviate the risk throughout the years of the contract. As noted in the Investment Requirement and Cost Assignment subsection below, the requirements for deposits throughout the life of the contract can offset some of this risk. A deposit can offset stranded costs if usage is below a minimum threshold or if the customer shuts down.

The contract itself can outline cost allocations to the customer, deposit terms, and credits to be returned to the customer for continued electric service and initial infrastructure investment to support the customer's load. Any known increases in load throughout the contract period can be addressed at the time of the contract being drafted, or through contract amendments, particularly if there is additional investment required to bring that load onto the system.

[7] Examples of these proposed tariffs include Kentucky Power Company's New Tarif Industrial General Service: https://psc.ky.gov/pscscf/2024%20cases/2024-00305/20240830_Kentucky%20Power%20Tariff%20Filing.pdf and Appalachian Power Company and Wheeling Power Company's Application for Approval of Revisions of Schedules LCP and IP https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=625853&NotType=WebDocket.

Load and Power Factors

In addition to contract and minimum demand levels, tariffs and special contracts also may establish a minimum load factor or a range for power factor to encourage consistent monthly energy usage. Encouraging consistent energy usage will ensure that utilities can cover the fixed cost to serve the load. Demand ratchets, discussed below, are another method of ensuring fixed costs are covered.

Load factor is the average power usage compared to peak power usage during the same period, measured as a percentage. The higher the percentage indicates the more efficient use of electricity. The desired effect of a minimum load factor is to smooth out demand peaks to lower the strain on the power infrastructure and increase reliability.

Power factor, also measured as a percentage, indicates the effectiveness of the use of incoming power by a specific load or equipment. The higher the power factor, the more efficient performance of the load/equipment. More efficient usage of power can reduce energy costs and system losses, which translates into savings for all customers.

Load factors are dependent upon the customer's usage. For example, an office building, which has low usage on weekends, can experience a load factor of 40-60%, whereas a cryptomining facility that is dependent on the value of the currency may have a lower load factor due to spikey monthly usage. A large load data center, since it is constantly active, will have a high load factor of 90-100%. Ultimately, the load factor is dependent on the type of customer/industry. The utility can include a load factor charge to penalize those customers that do not maintain a certain load factor, based on the type of customers being served under that tariff.

Demand Ratchet

While residential customers are billed on energy usage, commercial and industrial tariffs also include a demand charge component. A demand charge, which is used to cover fixed costs associated with a customer's load, is based upon the peak demand during the billing period.[8] The demand charge typically reflects a per kilowatt hour charge based upon the highest level of demand during a billing period. This charge allows the utility to recover the cost of providing a reliable service during those high peaks. Utilities must provide reliable service at those maximum demand levels; however, a customer may have significant shifts in demand by hour, day, or month.

[8] Peak demand is based on the level of demand over a 15-minute period.

Demand Ratchet Tariff Example

Here is an example of an 80% demand ratchet over an 11-month period. In this example, the demand charge is based upon the greater of the actual peak demand in the billing month or 80% of the highest peak demand recognized in the prior 11-month period.

Ex. In September, a facility's maximum peak demand was 400 kW and in the prior 11-months, the facility recognized its highest demand peak of 560 kW in July. The demand ratchet dictates that the demand charge for the month of September would be based on the greater of the 400 kW of actual usage or 448 kW (80% of 560 kW). Therefore, the facility would be charged a peak demand of 448 kW, since that is greater, resulting in the customer paying for 48 kW of demand it did not actually use.

One way that utilities reduce risks of serving customers that have large swings in demand is to assess demand charges using a demand ratchet.[9] The demand ratchet establishes the level of the demand charge based upon the actual peak demand, or a percentage of the highest demand recorded during the previous certain number of months, whichever is greater. The percentage of demand typically ranges from 80-85% of the previous period's demand, and the previous period can range from 9 to 11 months. Utilizing a demand ratchet encourages the customer to maintain a level of demand that is consistent as the customer would have to pay for demand not utilized if it does not.

Demand Shedding

Another safeguard that is often included or available is the opportunity to shed load, either through an interruptible tariff or through a demand response program. The availability of an interruptible tariff or a formal demand response program appears to be dependent upon the size of the service territory and utility type (investor-owned / cooperative / municipality). Even without a formal avenue to shed load, such as an interruptible tariff or demand response program, some tariffs included language for the utility to be able to enter into demand shedding agreements directly with customers. The highlighted language below identifies Black Hills Energy's Blockchain Interruptible Service requirements for interruptible service that is detailed in individual service contracts.[10]

[9] For more information on demand, please visit; https://www.santeecooper.com/rates/understanding-your-demand/#:~:text=Ratchet%20%E2%80%93%20A%20ratchet%20charge%20is,work%20and%20is%20being%20lost..

[10] Cheyenne Light Fuel and Power Company d/b/a Black Hills Energy, Electric Rates Blockchain Interruptible Service: https://ir.blackhillscorp.com/static-files/5c33d769-2d19-43f8-8898-a37af25481ef#:~:text=This%20tariff%20is%20applicable%20to,Agreement")%20with%20the%20Company.

ELECTRIC RATES

BLOCKCHAIN INTERRUPTIBLE SERVICE ("BCIS")

The Agreement shall be in accordance with the provisions of this BCIS tariff and at a minimum shall include:

1. Electric service is for new interruptible load expected to be 10,000 kW or greater;
2. A term of at least two (2) years;
3. Specific pricing for all electricity purchased, with the pricing terms being subject to renegotiation at least every three (3) years;
4. Identification of Customer and Company costs for any required new electric infrastructure;
5. Details specifying how service will be interrupted by the Company;
6. Negotiated service interruption provisions (size of interruptible load, notice of planned interruption, duration of interruption, and maximum hours of interruption per year) ;
7. BCIS customers that fail to interrupt service as required by the Agreement shall be responsible for all costs incurred by the Company due to such failure;
8. A release of liability of the Company for any losses or damages, including consequential damages, caused by or resulting from any interruption of service;

With the level of some proposed data centers' load being equivalent to 50% or more of an entire system's load, utilities and their systems would benefit from having a tariff that allows for interruptible service, either through a formalized tariff or on a case-by-case basis, which can be negotiated with or without a special contract. As these loads are large and unique compared to past loads, having a flexible interruptible tariff will likely allow a utility to accommodate customers while accounting for risk and available system capacity. Not one of the tariffs reviewed identified the maximum or minimum level of load that can be interruptible, rather the tariffs required the service agreement to identify the level of firm load, or the amount of demand that cannot be interrupted. Some contracts did include a maximum number of hours or interruption events; however, it is not necessary to establish a maximum number of hours or event durations within the tariff. This can be negotiated based upon the load and customer. For transparency and fairness purposes, the utilities may want to disclose in the tariff the compensation for interruptible service.

Commercial and industrial ("C&I") demand response and interruptible load programs are typically more cost-effective than residential demand response programs. Depending on program saturation, C&I can provide a more significant shed load than a residential program due to a higher level of load per customer.

It is important that pricing of interruptible and demand response efforts be done in moderation, with enough incentive to the ratepayer to offset the inconvenience of shedding load and reducing activity, but not too high as to incentivize high profitability from shedding load as it can be costly to other ratepayers. Pricing structure, limitations on overall hours of interruption, and having the utility determine when an interruptible or demand response event occurs can eliminate concerns related to profitability. Compensation for demand response efforts should be considered based upon the level of load that can be shed and how quickly the load can respond to a request. Commercial and industrial customers, depending on their industry, can typically shed higher amounts of load and in a short period of time (within 30 minutes to an hour). The ability to provide large amounts of load shedding quickly should be compensated appropriately to encourage customers to do so when necessary. Demand response or interruptible tariff compensation for load shedding should be compared among similar rate classes and rate design elements, such as number of hours and events and duration of the event. These factors, along with the need for capacity in a service territory, can influence the level of compensation offered for demand shedding.

Interruptible tariffs can have several elements to establish safeguards for the grid and to ensure that load reductions do occur. In Texas, there have been capacity issues when an interruptible service client does not respond to the request to reduce load. Some provisions that can be included in an interruptible service agreement include:

- Number of annual events and total hours. The number of events and overall hours for interruption per year should not be detrimental to the business.
- Event duration and seasonal requirements. There may be periods of time when demand reduction is more valuable than others, depending on the utility's peak season. This can influence the length of events, typically around two to four hours, and the timing of the events.
- Details of compensation that could be based on the level of demand or energy reduction, such as the dollar per megawatt, or could be offered through a discounted energy price throughout the year for participating.
- Penalty for not responding to an interruption event. The utility is relying on the reduction in load; however, if a customer does not respond, it can increase energy costs for others. Therefore, a penalty should be assessed to offset that increase in cost for not responding to the event and to encourage customer participation.

Investment Requirements and Cost Assignment

One way to limit risk to existing ratepayers from the addition of the customer's load is to assign costs to the customer, require contributions in aid of construction for system upgrades, and require surety bonds or minimum bills equivalent to a portion of the annual bill. These safeguards can lessen the risk to ratepayers by requiring the customer to be invested in the location. Assignment of costs for new or expanded electric service is not a new concept. Customers, both residential and commercial, can be responsible for line extensions and other identified costs to receive service. Cost assignments should be designated in the tariff, including guidelines on how to calculate the minimum bill.[11]

Concern: The cost assignment concerns are not only limited within a service territory but also across state lines for transmission infrastructure. In April, the Federal Energy Regulatory Commission ("FERC") approved a regional cost assignment for the PJM. The transmission upgrades are being implemented to support a cluster of data centers in northern Virginia. While the location of the data centers is in Virginia, ratepayers in Maryland have been assigned 10%

Depending on the size and characteristics of the load, there is potential for other customers throughout the service territory subsidizing the cost of service for a large load customer, particularly when discounted rates are provided to the large load customer. One way to avoid subsidization for a particular customer is to evaluate if the revenues received from the large load customer exceed the cost to serve the customer. An example of this is Evergy Missouri Metro's Special High-Load Factor Market Rate ("Schedule MKT"), noted in Table 1 below, which requires the utility to track all costs to serve each customer under this tariff and verify that the revenue collected is higher.[12] This provision is designed to ensure that non-Schedule MKT customers are not held liable for any deficiencies in revenues or from stranded investment or costs from serving the customer over the length of the contract. To track the costs and revenues associated with this, the tariff outlines the following:

- Utility must identify costs and revenues with each customer on the Schedule MKT in its books and records.
- During a rate proceeding, the portion of the revenue requirement associated with the costs to serve the customer shall be assigned to the customer and not the overall customer base.
- If the customer's rate revenues do not exceed the cost to serve the customer in the customer's revenue requirement, there must be an additional revenue adjustment to cover the shortfall in a true-up period.
- The customer served by Schedule MKT can argue whether a specific quantifiable societal or other benefit (e.g., added jobs or tax revenue) should be considered to offset the deficiency.

One example of a cost assigned could be for a feasibility study. As large new loads are requested on an electric system, a feasibility study is usually conducted to understand what system upgrades may be needed to accommodate the load safely, depending on size thresholds, including transmission and distribution upgrades.[13] Sometimes, the tariff includes

[11] Source for orange box: *Utilities poised for datacenter earnings boost, want clarity on cost recovery,* Allison Good, April 18, 2024, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utilities-poised-for-datacenter-earnings-boost-want-clarity-on-cost-recovery-81249390, accessed October 18, 2024.

[12] Evergy Missouri Metro's Special High-Load Factor Market Rate Schedule MKT can be found here: https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf

[13] Requirements for a feasibility study is dependent upon the service territory and the jurisdiction.

a provision that assigns the cost of the feasibility study on the customer, like in New York, which is shown below.[14]

> **RIDER A**
>
> **RATES AND CHARGES FOR CUSTOMERS REQUESTING HIGH DENSITY LOAD (“HDL”) SERVICE**
>
> **B. APPLICATION FOR SERVICE:**
>
> b. Upon payment of security acceptable to the Utility, the Utility shall conduct, or cause to be conducted a feasibility study to evaluate whether the requested load can be safely served by the Utility.
>
> a. The feasibility study will identify what, if any, upgrades to the Utility’s facilities are required to serve the customer.
>
> **B. CUSTOMER COST CONTRIBUTION**
>
> A Customer requesting service under this Rider will be responsible for:
>
> a. reasonable costs of conducting the feasibility study; and

If the system can accommodate the load with minimal system upgrades, the risk associated with the customer’s electric service is likely limited. However, if significant upgrades are required, then those costs serve as potential risks to existing ratepayers. The cost for the feasibility study should be assessed to the customer seeking interconnection; sometimes this is done through a flat fee. Furthermore, the charges associated with upgrades, including the proportional cost of acquiring or building new generation to serve the customer, should be required to be funded by the customer and tied to a deposit or contribution in aid of construction, to limit risk exposure of stranded assets to the existing customer base.

Historically, a large load facility, like an Amazon warehouse or industrial process, is more permanent and will contribute towards cost recovery immediately, as the plant ramps up in its first year of operation and then will remain on the system for the foreseeable future. On the contrary, cryptocurrency mining facilities are seen as volatile as they are price sensitive and can be operated in non-permanent facilities, and traditional data centers can take years

[14] See Leaf 95-96 of Rider A Rates and Charges for Customers Requesting High Density Load (“HDL”) Service, https://ets.dps.ny.gov/ets_web/search/showPDF.cfm?%3B%3AIS%20%3B%2A%29LOUNWD%5CJ%5E8%2B"%2B5%2F0MD%2F0%28%231V%28S<WX%0A, accessed November 11, 2024.

to get to full capacity, which can delay cost recovery and place the burden on existing ratepayers.

A definition and summary of how each requirement serves as a safeguard is provided in Table 1 below. In addition, each requirement has an example and is linked to one of the tariffs discussed in Appendix A.

Table 1 Common Tariffs Requirements

Requirement	Definition	Serves as a Safeguard?	Example
Contract Term Length	Length of the service agreement. It can be limited to a minimum and/or maximum number of years. In addition to a contract term, there could be a term length for pricing terms.	Yes. A limited term could limit potential risk to customers, as well as ensure that system upgrades or investment in new generation are paid for by the new customer rather than existing ratepayers.	Evergy Missouri Metro limits contract lengths to 10 years, with pricing terms no more than 5 years
Minimum Demand	Level of demand needed to qualify for the tariff	Yes. Provides a threshold for customers to qualify for the tariff and can be designed to target high demand users	Contracts varied significantly between 500 kW and 100,000 kWh per month. This will be dependent on the service territory's load compared to the new customer load.
Minimum Load Factor	Average power usage compared to peak power usage during the same period. The higher the percentage, the more efficiently the electricity is being used.	Yes. Establishing a penalty for not achieving a minimum load factor will encourage the customer to have energy usage consistent with its maximum peak. Smoothing out peaks can lower the strain on power infrastructure and reliability.	If required, the minimum load factor required was 85%. The reduces the opportunity for significant fluctuations in load and thus the reliability of service is more easily predictable by the utility.

Requirement	Definition	Serves as a Safeguard?	Example
Range for Power Factor	Effectiveness of incoming power by a specific load (or equipment) at a given time. The higher the power factor, the more efficient the load's performance.	Yes. Inefficient power usage can result in additional costs on the system. Establishing a power factor range can reduce energy costs, reduce system losses, and improve voltage regulation, which can limit outages and allow for additional loads to be added to the system from that customer.	If required, this would be 90% or greater. The Montana-Dakota Utilities Company requires a power actor between 97% lagging and 97% leading.
Requirements for Investment	Designated cost elements that are funded directly by the new customer, sometime viewed as a deposit in the form of Contributions in Aid of Construction ("CIAC"), bonds, or actual payments. This investment may be returned to the customer overtime.	Yes. Delineating expenses for the customer to pay or cover with a deposit eliminates concerns about discriminatory rates. Additionally, it encourages investment by the new customers, thus removing the risk from existing ratepayers, and ensures a term commitment to the service territory.	This requirement varied by utility, but could include new electric infrastructure, line extension or system upgrades, and feasibility studies. Other utilities require bonds for Value of Lost Load dependent upon the RTO requirements or a bond for the average bill for a time period.
Cost Assignment	Designation of which expenses related to providing service to the customer is the responsibility of the customer and not socialized to other ratepayers.	Yes. Eliminates the risk of a customer not paying their fair share of the investment in providing electric service. Some commissions have required utilities to track all costs related to the customer to ensure during rate cases that the revenues from the customer offset expenses to provide service to the customer.	Evergy Missouri Metro has a requirement to track all costs to serve the customer and verify that revenue collected is higher. The New York Municipal Power Agency requires costs associated with the purchased power adjustment and rate statement to be allocated to the customer.

Requirement	Definition	Serves as a Safeguard?	Example
Requirement to Shed Load	Utility requires the customer to drop a portion of its load during events with notice.	Yes. Increases system reliability and reduces capacity costs, depending on the type of event requiring load shedding. This could be done through an interruptible service rider, service agreement, or a formal demand response program.	Approximately half of the tariffs have a load shed requirement. The majority vary by contract. If there is an interruptible schedule, the customer is typically not subject to a demand response program. If there is not an interruptible program, then demand response programs were often, but not always available. Grant County Public Utility District does not offer an interruptible tariff or a demand response program through tariffs but does do arrangements on a customer-by-customer basis.
Load Subject to Interruptible	Can be a determined capacity subject to interruptible service (such as non-firm demand) or the amount of time when an interruption event may be announced.	Yes. While the tariff language can indicate a cap on the level of interruptible load to be included or excluded, it is recommended that the level of load be negotiated on a per customer basis.	For those requiring interruptible load, the amount of load subject is established in the contract with the customer. It is often limited to non-firm demand.
Maximum Hours of Interruptible per Year	A defined limitation on the number of hours that load can be interrupted per year. This is typically accompanied by penalty language in the event the customer does not respond to the interruptible load request.	Yes. Designating a maximum number of events or hours, or even length of events, can encourage participation from customers in an interruptible schedule.	There is a significant range in the number of hours, if any were specified in the tariff. Entergy Arkansas limits the maximum number of hours to 40 or 80 hours, depending on notice time, while other utilities such as Idaho Power Company set limits of 225 hours per year.

2024 Proposed Large Load Tariffs

Ohio

In Ohio, there are opposing opinions between the utility, AEP Ohio, and the technology giants like Amazon, Google, Meta, as well as the Data Center Coalition on the structure of large load tariffs. In July 2024, AEP Ohio, in its role as a distribution utility, proposed two new tariff designs as a result of an influx of data center load requests in its service territory in May 2024.[15] The initially-proposed tariff included two components, a Data Center Power designed for customers with a monthly demand of 25 MW or more, and a second Mobile Data Center component for cryptomining facilities with a monthly demand of 1 MW or greater.[16]

As of January 2025, there were two competing settlements that diverged substantially from the initial proposal, and the case is still pending before the Ohio Public Utilities Commission, with hearing dates in December 2024 and January 2025.[17] Depending on the decision in the case, it could set precedent and baseline safeguards throughout the nation as the filing's proposed terms have not been collectively included in any other utility tariffs for data centers.

The primary components of the initial proposal were changes to an existing rider, known as the Basic Transmission Cost Rider ("BTCR").[18] Currently the BTCR sets the minimum demand charge for a customer at 60% of the contracted capacity. AEP Ohio's initial proposal indicated that the amount was too low and sought to increase the minimum demand charge to 90-95% of the contracted demand. This is due to the significant difference for large load customers between the minimum and actual bill if all contracted load is utilized. In addition, AEP Ohio initially requested that data centers enter into 10-year service contracts to ensure funding for the significant investment that the utility will need to make over the next decade to accommodate the data center load interconnection requests. An exit fee was proposed for customers in the 10-year contract to pay to leave the contract after 5 years. As noted in the safeguard above, AEP Ohio is implementing elements to provide safeguards not only for ratepayers but also for the utility itself as it endeavors to grow the system. If the data centers are not located in the service territory after AEP Ohio builds out the transmission system, the unneeded capacity costs will be passed along to ratepayers located throughout PJM.

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[15] Application for approval of New Tariffs By Ohio Power Company, *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers,* Case No. 24-508-EL-ATA, https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24E13B42822J00948.
[16] Direct testimony of Matthew S McKenzie on behalf of Ohio Power Company, *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers,* Case no. 24-508-EL-ATA, tariff pages begin on page 32, https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24E13B43247C00950.
[17] Full docket available at: https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=24-0508
[18] Direct testimony of Matthew S McKenzie on behalf of Ohio Power Company, *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers,* Case no. 24-508-EL-ATA, tariff pages begin on pages 15-16, https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24E13B43247C00950.

Provisions within the initially-proposed tariff that can serve as safeguards for ratepayers are summarized below:

- Minimum Load Eligibility
  - Tariff is applicable to customers requesting a minimum demand of 25 MW of service at a single location. The tariff would also be applicable to a parent company with multiple data centers that have an aggregate monthly maximum demand greater than 25 MW within a 24-month period.
    - By establishing aggregate demand for parent companies, this ensures that data centers locating around the service territory are not circumventing the eligibility requirements for the tariff.
- Minimum Billing Demand
  - Load ramp period which establishes monthly peak load requirements as the facility comes online and requires that the overall requested load of the facility commence service within three years. During the ramp up period, billing demand shall not be less than 90% of the customer's load ramp contract capacity.
    - This ensures that the fixed costs associated with serving this customer's level of load are paid for by the customer. Even if the customer has not reached that level of demand, the utility is already incurring the cost to provide services at the contracted demand levels.
  - Monthly billing demand once a customer is beyond the load ramp period shall not be less than 90% of the greater of (a) customer's contracted capacity or (b) customer highest previously established monthly billing demand during the past 11 months.
    - The inclusion of a demand ratchet ensures the customer is paying the fixed charges associated with this customer's demand.
- Range for Power Factor
  - Includes an excess reactive demand charge, assessed for each kVAR of reactive demand, leading or lagging, in excess of 50% of the metered demand.
    - This ensures that the customer is paying its fair share of the fixed charges to provide service, as it is based on the level of capacity contracted and not used.
- Retail Supplier Notice
  - If a customer wants to switch from standard offer service to a competitive supplier, then the customer must provide the utility with notice 60 days prior to the end of the supply period covered by the auction. The customer must remain on standard offer service for the six month period in which the customer has been receiving standard offer service.
    - This ensures that the utility does not over procure energy through the supply auctions.
- Contract Period
  - The initial contract period cannot be less than 10 years, including the load ramp period. There is an exit fee, equal to the minimum charges for 36 months after the notice of the termination, if the customer elects to leave after the completion of the 5th year of the contract.

- The contract term is the average contract length and has an exit fee schedule that is designed to avoid stranded asset costs.

- Collateral Requirements
  - Customers must meet a credit and cash collateral requirement relative to 50% of the total minimum charges for the full contract term. The amount of collateral is reduced by one year's minimum charges for each year the customer is energized and makes on-time electric service payments. If the financial position of the customer changes over the term of the contract, the Company may ask for updated information and re-evaluate the collateral requirements.
    - This provision is unique compared to others reviewed, as the collateral is for the full contract term and the reduction of the collateral is based upon timely payments. Furthermore, the collateral provisions are typically calculated ahead of the contract signing and do not have re-evaluation requirements. This last provision would be useful as the industries related to cryptomining and data centers are ever evolving and dependent on a number of factors, such as contracts and price signals.
- Demand response
  - The initially proposed contract lacks a provision related to interruption outside of a requirement for the customer to reduce its demand during an RTO- or company-declared emergency event. There is a lack of detail related to the emergency events and no mention of voluntary interruptible events. While it is important to be able to react to emergency events, given the size of the loads anticipated, the ability to interrupt load for reliability purposes, particularly to address local reliability issues, would be of significant benefit to the system. While it may not be a standard provision, this tariff should have a special contract provision to determine interruptible load levels from large load facilities.

As noted above, as of this publication date, the case was ongoing with a multi-day hearing held on many of the issues covered above.

Indiana

On November 22, 2024, Indiana Michigan Power Company (I&M) introduced a settlement, involving all parties to the case including tech giants Amazon and Google and the Indiana Office of Utility Consumer Counselor, to amend their industrial power tariff.[19] This tariff is applicable to new or expanded facilities seeking to contract capacity of 70 MW or more or 150 MW of aggregated load across a company. Loads meeting this requirement are required to

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[19] Before the Indiana Utility Regulatory Commission, *In the Matter of Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.*, Cause No. 46097, filed November 22, 2024, https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/4aae5d78-18a9-ef11-8a6a-001dd80bd98a/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46097_IndMich_Submission%20of%20Unopposed%20Settlement%20Agreement%20and%20Unopposed%20Motion%20for%20Acceptance%20of%20Out%20of%20Time%20Filing_112224.pdf.

have initial contracts of at least 12 years. The contract for the full load can start after a five-year ramp up period. Additionally, without incurring any fees, after the first five years of the contract, a customer can reduce its contract capacity by up to 20 percent, as long as the customer notifies I&M through written notice 42 months prior to the start of a PJM Interconnection delivery year. Contracts can be terminated, or contract capacity can be reduced beyond 20%, if an exit fee is paid and done so under the conditions listed above for reduced capacity.

In addition to these contract terms, the I&M settlement put forth several provisions related to I&M's integrated resource planning ("IRP"), interconnection, demand response, and clean tariffs. As part of its IRP, I&M has agreed to study grid enhancing technologies and tools to maximize the transmission grid efficiency and to relay the study's result in the next IRP. I&M also agreed to discuss any changes to its interconnection process with stakeholders, including large load entry requirements to the utility's queue, interconnection requirements, and load ramping requirements. To address emergency load reduction plans, I&M will meet with the parties to the settlement to discuss emergency response procedures and demand response opportunities for customers under this tariff. Finally, I&M agreed to collaborate with settling parties to develop a clean transition tariff proposal that will allow participants to support investment in carbon-free resources and ensure that all program costs are covered by participants and remain consistent with the five pillars in Indiana Code §8-1-2-0.6.

As part of the agreement, beginning six months after approval, I&M would provide semi-confidential reports to the Indiana Utility Regulatory Commission on new and pending large load customers. The settlement, which as of the publication of this report, has not been approved yet by the Commission,[20] also requires Amazon Web Services, Microsoft, and Google to each give $500,000 annually, for five years, to the Indiana Community Action Association, which supports low-income individuals in Indiana.

North and South Carolina

In North and South Carolina, Duke Energy has several initiatives they have proposed or adopted to address the growing demand from high energy users, including from data centers.

New rates for Data Centers and Industrial Customers

Duke Energy conducted a study which evaluated ways that high-volume users could pay their fair share into the system. The reason behind the focus has to do with the constrained power supply on their system compared to a few years ago. Duke is anticipating 18,000 gigawatt hours of additional load from new customers by 2028, with 25% of that load coming from data centers.[21] As a result of the study, Duke is adding electric supply contract terms for data centers and factories which require a minimum-take clause and upfront payments for infrastructure investments. The minimum-take clause requires qualifying customers to pay

[20] Full docket at https://iurc.portal.in.gov/docketed-case-details/?id=b8cd5780-0546-ef11-8409-001dd803817e

[21] *Duke Energy seeks take or pay power contracts for data centers,* Laila Kearney, May 7, 2024, https://www.reuters.com/business/energy/duke-energy-seeks-take-or-pay-power-contracts-data-centers-2024-05-07/ , accessed October 18, 2024.

for a certain amount of power regardless of actual use and requires upfront contributions for investment in system upgrades.

Clean Energy Tariff Options

In May 2024, Duke Energy signed memorandums of understanding with Amazon, Google, Microsoft, and Nucor to explore carbon-free energy generation and clean tariff options, called the Accelerating Clean Energy ("ACE") tariffs. The ACE framework includes a Clean Transition Tariff where Duke Energy would be able to provide commercial and industrial customers with new carbon-free energy options, while providing protection for non-participating customers and potentially lowering the long-term costs of investing in clean energy technologies.[22] The framework being proposed will occur in phases, with the purpose of helping customers meet their clean energy goals through tariff design and financing options.

One of those items that occurred outside of the framework included a green tariff proposal called the Green Source Advantage Choice Program, which was approved by the North Carolina Utilities Commission in July 2024. [23] The rider is offered to non-residential customers "who elect to direct the Company to procure renewable energy on behalf of the Customer's behalf" and who have a minimum maximum annual peak demand of 1 MW or an aggregated annual peak demand of 5 MW.[24] The tariff allows for large customers to increase Duke Energy's investment in solar energy by 150 MW per year, through a resource acceleration option in which customers can sponsor projects not selected in the company's annul competitive bidding process. The program limits procurement of renewables by the Duke Energy companies in North Carolina as follows:

- **4,000 MW of renewable energy from Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP")**
- **DEP and DEC can only collectively own 2,200 MW of the capacity under this tariff**
- **The remaining 1,800 MW of renewable energy facilities must be developed by third parties that have entered into PPA's with one of the Companies or an eligible Green Source Advantage Choice customer.**
- **Annually, the Company must reserve 10% of the capacity for subscription by qualifying economic development customers. At the end of the third quarter each year, any unsubscribed economic development capacity can be released to all other qualified customers.**

Some of the projections in place for the service territories customers include:

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[22] *Responding to growing demand, Duke Energy, Amazon, Google, Microsoft, and Nucor execute agreements to accelerate clean energy options,* Duke Energy News Center, May 29, 2024, https://news.duke-energy.com/releases/responding-to-growing-demand-duke-energy-amazon-google-microsoft-and-nucor-execute-agreements-to-accelerate-clean-energy-options, accessed October 18, 2024.
[23] Docket Nos. E-2, SUB 1314 and E-7, SUB 1289, Before the North Carolina Utilities Commission, *In the Matter of Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Choice Program and Rider GSAC,* Commission Order dated July 31, 2024, *https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=acd1a9a3-9b00-4a3a-9700-4dae3a293cc2.*.
[24] Compliance tariff currently under review by the North Carolina Utilities Commission, Rider GSAC Green Source Advantage Choice, dated August 14, 2024, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=0d45934a-06ea-478d-8301-7a3b4377415a.

- Customers can pay for their portion of clean energy costs either through an up-front contribution in aid of construction payment or on their bill over time through a levelized demand charge payment.
- If a customer elects battery storage, the charging cost will be assessed as a charge to the customer and the discharging value will be assessed as a credit to the customer, effectively netting the amounts on the customer bill.

The docket for this item is ongoing and the tariff has not yet been approved by the Commission. Additionally, the overall ACE framework is an ongoing process that should continue to be monitored.

West Virginia and Kentucky

On July 18, 2024, Appalachian Power Company and Wheeling Power Company filed proposed revisions to its Schedules LCP and IP to include tariff terms related to the addition of customers with loads of 200 MW or greater in West Virginia.[25] On August 30, 2024, Kentucky Power Company filed revisions to its Tariff Industrial General Service ("Tariff I.G.S.") to address customers with loads of 150 MW or greater in Kentucky.[26] The initially-proposed changes to the tariffs were the same and include the following:

- Initial contract period of 20 years
- Either the customer or utility must provide at least five years' written notice to discontinue service of the terms of the schedule; however, this shall not reduce the 20-year initial contract term.
- If a permanent closure by the customers occurs in the first five years of the contract, the customer must pay a one-time exit fee equal to five years of minimum billing.
- A customer must provide written notice five years in advance to reduce the contract capacity by up to 20 percent of the contract capacity; however, mutual agreement can result in reduce contract capacity in less than five years.
- Demand ratchet requirement of no less than 90 percent of the greater of (a) the customer's on-peak contract capacity, or (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) the customer's maximum demand created during the billing month.
- Collateral is based upon creditworthiness of the customer. The collateral shall be equal to 24 times the customer's previous maximum monthly non-fuel bill.

[25] Before the West Virginia Public Service Commission, *In the Matter of Appalachian Power Company and Wheeling Power Company Application for Approval of Revisions to Schedules LCP and IP,* Case No. 24-0611-E-T-PW, https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=625853&NotType=WebDocket.

[26] Before the Kentucky Public Service Commission, *In the Matter of Kentucky Power Company's First Revised Tariff Sheet 1-1 (Index), First Revised Tariff Sheet 8-2 (Tariff I.G.S.), and Original Tariff Sheet 8-3 (Tariff I.G.S.),* Case No.2024-0830, https://psc.ky.gov/pscscf/2024%20cases/2024-00305//20240830_Kentucky%20Power%20Tariff%20Filing.pdf.

As of January 2025, this case is still pending before respective Commissions.[27] Notably, on January 22, 2025, the parties in the West Virginia proceeding filed a joint stipulation and settlement agreement signed by all parties. Under the terms of the settlement agreement, which is still pending approval, the large load tariff will apply to customers seeking to contract capacity of 100 MW or more or 150 MW of aggregated load across a company. Many of the settlement's terms mirror the terms of the Indiana settlement discussed above: for example, terms pertaining to minimum contract length, monthly billing demand, and reducing capacity during the contract period. The settlement also requires the utilities to track revenue and capital investments related to new large load customers, with the customers having the ability to seek confidentiality protections. The utilities, with input from the settling parties, must also conduct or utilize analyses to minimize transmission needs, but the cost of such analysis cannot exceed $50,000 pending further agreement.

Additional Considerations

Powering large loads from cryptocurrency mining and data centers is still evolving, which means there are changes announced monthly. In addition to reviewing the tariffs, several proceedings before public service commissions were reviewed to assess the fairness, reasonableness, and non-discriminatory elements of various contracts considered by public service commissions, in order to to better understand which safeguards have legal standing or precedent. Using the information from those proceedings and the tariffs discussed in the second section, there are additional rate provisions that should be considered when designing a large load tariff. These provisions will not only safeguard existing ratepayers, but also the efforts to achieve clean and renewable energy goals.

Avoid Discriminatory Rate Structures

As established by the Robinson-Patman Act, the Federal Trade Commission prohibits public service commissions from allowing unduly discriminatory rates. Public service commissions require approved rate structures to be just, reasonable, and non-preferential. While some commissions have approved tariffs that explicitly identify cryptomining and data centers, concerns regarding discriminatory rates and tariffs have been rising up throughout the states, as well at the federal level.

To avoid discriminating against certain industries, tariffs can include definitions and categories of service that can be related to the volatile and non-permanent nature of cryptomining and data centers.

Rather than explicitly naming cryptomining or data centers, utility tariffs have used the following definitions for high density tariffs:

- "Load that is portable and distributable"
- "High energy use density"
- "High variable load growth or load reduction"
- "permanency of service cannot be reasonable assured"
- "Evolving Industry"

[27] Joint Stipulation and Agreement for Settlement, Case No. 24-0611-E-T-PW, filed Jan. 22, 2025, https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=634939&NotType=WebDocket.

Black Hills Energy in Colorado offers a service tariff for "Indeterminate Service," which is defined below.[28]

BLACK HILLS COLORADO ELECTRIC, LLC
d/b/a BLACK HILLS ENERGY

K. Indeterminate Service: Service that is of an indefinite or indeterminate nature where the amount and permanency of service cannot be reasonably assured in order to predict the revenue stream from applicant. For purposes of uniform application, "Indeterminate Service" may include such service as may be required for the speculative development of property, mobile buildings, mines, quarries, oil or gas wells, sand pits and other ventures that may reasonably be deemed to be speculative in nature.

In the Grant County Public Utility District ("PUD") service territory, in Washington, rather than adopting a tariff explicitly for cryptomining facilities and volatile users, the PUD adopted a new rate class, known as "evolving industries." Rather than explicitly call out specific users, it defined characteristics that those industries are known for. The definition of Evolving Industries rate class is based on three risk factors as shown below.[29] This rate class is charged a different rate than other C&I customers.

To decide if an industry falls into the evolving industries class, the district used a test focused on certain risk factors presented by the industry in question. These risks are:

- Regulatory risk — risk of detrimental changes to regulation with the potential to render the industry inviable within a foreseeable time horizon;
- Business risk — potential for cessation or significant reduction of service due to a concentration of business risk in an evolving or unproven industry or in the value of the customer's primary output; and
- Concentration risk — potential for significant load concentration within the district's service territory resulting in a meaningful aggregate impact and corresponding future risk to the district's revenue stream. Evaluation would begin to occur when industry concentration of existing and service request queue customer loads exceeds 5% of the district's total load.

[28] Black Hills Colorado Electric LLC d/b/a/ Black Hills Energy tariffs: https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/coe-rates-tariff.pdf, see PDF page 220.
[29] *A Blow to Crypto Miners Disputing Local Energy Rates,* James Gatto and Andrew Mina, April 10, 2020, https://www.sheppardmullin.com/media/publication/1859_A%20Blow%20To%20Crypto%20Miners%20Disputing%20Local%20Energy%20Rates.pdf, accessed October 18, 2024.

Renewable Energy Requirements

To date, most tariffs related to cryptomining and data centers do not have renewable energy or clean energy procurement requirements. Most efforts to have clean energy used to power these services are achieved through renewable energy credits pushed by a corporate goal rather than from a utility. Of the tariffs and proceedings reviewed, only one had an explicit renewable energy provision. Renewable energy requirements or clean energy tariffs should be designed in accordance with the "three pillars" of clean energy:

1. **Incremental – energy is from a clean energy source that incremental to existing generation.**
2. **Temporality or being time-matched – power is generated in the same hour it is consumed.**
3. **Deliverable – power is deliverable in the same grid region.**

In the Evergy Missouri Metro service territory, customers are subject to the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") charge, which is an adjustable rate to allow for the utility to recover prudently-incurred costs related to procurement of renewable energy standard costs that are above and beyond the renewable energy costs already included in base rates. The provision included below states that a customer on Schedule MKT must pay future RESRAM charges unless they have renewable attributes that support its load which are greater than or equal to the existing Renewable Energy Standard.[30] As written, the provision rewards customers under this tariff if they are procuring renewable attributes on their own. Please note that the provision does not require actual investment in renewable energy resources to directly serve the load.

Special High-Load Factor Market Rate
Schedule MKT

6. A Schedule MKT Customer shall be subject to any future RESRAM charges imposed by Evergy Metro unless a Schedule MKT customer does have renewable attributes supporting its load greater than or equal to the then existing Renewable Energy Standard including any solar portfolio requirements. For Schedule MKT customers with renewable attributes supporting its load greater than or equal to the then existing Renewable Energy Standard, including any solar portfolio requirements, the MKT Customer's entire load will be subtracted from the calculation of total retail electric sales in in 20 CSR 4240-20.100. Renewable attributes means Renewable Energy Credits and solar Renewable Energy Credits that the MKT Customer has retired, or had retired on its behalf, documented annually from an established renewable registry.

While renewable energy credits are a step in the right direction, it is essential to include provisions to require data centers to invest in renewable energy in the surrounding community, either through investment in community solar, wind, roof top solar, and storage. Adding significant levels of load in communities, particularly those with clean energy targets,

[30] Evergy Missouri Metro Special High-Load Factor Market Rate Schedule MKT, https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf.

can derail clean energy achievements to date and could potentially result in increased environmental and health impacts due to increased generation needs. One of the three pillars of clean energy is incrementality. To achieve this, data centers must work to accelerate achievement of clean energy goals and/or offset any additional load powered by fossil fuel power plants. Utilities should work with potential customers to identify avenues to support the growth of renewable energy generation. For example, Meta worked with the Tennessee Valley Authority ("TVA") to develop a green tariff that supports the development of solar energy across the service territory to support Meta's corporate energy goals.[31] Depending on the economic development provisions, the green tariff is likely driving investment in the nearby community.

The clean transition tariff proposed by NV Energy in Nevada and Google and currently before the Public Utilities Commission of Nevada is another example of having clean energy serving large loads. The proposed tariff would allow for Google to power one of its data centers by purchasing power that NV Energy buys from the 115 MW Corsac Station Enhanced Geothermal Project at a price slightly higher than that paid by NV Energy. The tariff design prevents impacts to other ratepayers and allows Google to operate towards its 24/7 carbon free energy goal by 2030.

Power Purchase Agreements

Data center and cryptomining facilities are working with power plant operators and markets to establish power purchase agreements ("PPAs") to procure low-cost power options.[32] A power purchase agreement is between the buyer and seller, where a buyer commits to purchase an agreed amount of electricity over an established period. PPAs require approval from a utility commission if they involve a regulated utility.[33] There are two types of PPAs, physical and prepaid. A physical PPA is when the buyer takes physical delivery of the electricity generated either onsite in a behind-the-meter arrangement or offsite at a pre-determined point on the grid. A prepaid PPA is when the buyer pays the discounted cost of the PPA upfront. There is also something known as a virtual PPA, which is not a PPA but rather a financial instrument for a contract for difference.[34] Ultimately, state and local regulations on retail choice and electricity franchises establish the type of PPAs that are available by state.

As noted in Texas and by a case being considered by FERC, PPAs could have negative implications for other ratepayers. In Texas, a cryptocurrency company purchased low-cost electricity behind-the-meter through a PPA, which means that the energy utilized by the

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[31] More information on the green tariff is provided here: *Meta Partners with Silicon Rand for Seven New Solar Projects in Georgia and Tennessee,* December 15, 2022, https://www.siliconranch.com/stories/meta-partners-silicon-ranch-walton-emc-tva, accessed October 18, 2024.
[32] For more information on power purchase agreements, please see: *Customer Power Purchase Agreements,* United States Environmental Protection Agency, https://www.epa.gov/statelocalenergy/customer-power-purchase-agreements, accessed October 18, 2024.
[33] Wholesale power sales, which do not involve an end user, are within the purview of the Federal Energy Regulatory Commission.
[34] Virtual PPAs are considered a financial instrument and are regulated by the Securities and Exchange Commission.

PPA customer is not offered in the ERCOT market. During a heat wave in summer 2023, ERCOT issued a request for curtailment of power. In response, the cryptomining company, through its wholesale agreements, sold its power into ERCOT, making over $24 million on energy savings, more than three times the revenue it made from cryptomining the prior month.[35] Due to the load flexibility and price sensitivity of cryptomining, the facilities are able to game the system to create additional profits at a significant cost to ratepayers, who are less flexible to respond to demand pressures and are not compensated for doing so, as ERCOT does not currently offer residential demand response programs.

Another case where ratepayers may not benefit is for the interconnection service agreement ("ISAs") change for a facility to provide power to a co-located data center or mine. Currently, the 2,228-MW Susquehanna nuclear facility in Pennsylvania provides power to PJM as a baseload resource.[36] However, in March, Talen Energy, which owns the nuclear plant and had a cryptomining facility and data center on site, sold the data center to Amazon and planned to sell up to 980 MW of nuclear power to Amazon through a behind-the-meter power purchase agreement. In late November 2024, FERC denied the application.[37]

Economic Development

The potential for economic development through increased tax revenues and potential jobs from large load projects is intriguing and viewed as a positive element of potential load growth by politicians and utilities. However, the opportunities of increased tax revenue are often offset by state and local government tax credits used to entice certain industries or large loads to locate in a specific area. Additionally, utilities often offer discounted rates to large loads, which means that there is potential for existing ratepayers subsidizing that customer and lower potential tax revenue from the electric service. These discounts do not have to come from an economic development tariff, rather they can be supported by existing laws and incentives which provide these to new loads and entities building in certain areas.

The issue with economic development for cryptomining facilities and data centers is that they typically do not produce a substantial number of full-time equivalent jobs compared to the level of load added to the system. Furthermore, with the tax credits, there is limited net tax revenue being provided to the area.[38] As a result, the economic development discounts provided to customers result in limited to no benefits to the area and can expose those living in the area to added risks and increased bills, as previously identified.

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[35] "Texas Leaders worry that Bitcoin mines threaten to crash the state power grid," Keaton Peters, The Texas Tribune, July 10, 2024, https://www.texastribune.org/2024/07/10/texas-bitcoin-mine-noise-power-grid-cryptocurrency/, accessed October 18, 2024.

[36] *Talen-Amazon interconnection agreement needs extended FERC review: PJM Market Monitor,* Ethan Howland, July 11, 2024, https://www.utilitydive.com/news/talen-amazon-interconnection-agreement-ferc-constellation-vistra/721066/, accessed October 18, 2024.

[37] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241101-3061&optimized=false; https://www.utilitydive.com/news/ferc-interconnection-isa-talen-amazon-data-center-susquehanna-exelon/731841/

[38] Reference for the orange box text: *Protect SC Consumers From Data Center Costs,* Frank Knapp, South Carolina Daily Gazette, September 12, 2024, https://scdailygazette.com/2024/09/12/protect-sc-consumers-from-data-center-costs/, accessed October 18, 2024.

With the focus from politicians on attracting new industries, utilities may want to consider reviewing and revising their economic development riders that allow for discounted rates. One AEP utility, Indiana Michigan Power in Indiana, sunset its Economic Development Rider tariff and adopted its Economic Development Rider 2 tariff, which increased the level of minimum demand and the minimum number of full-time equivalent jobs and capital investment guidelines. A summary of the differences to qualify for a discounted rate through the Economic Development Rider 2 is provided below.[39]

INDIANA
Economic Development Rider 2 (EDR 2)

To qualify, a new or expanding business must meet the following minimum criteria:

New Customer Criteria

- Add 500 kW or greater to one metered account
- Create at least 20 full-time equivalent (FTE) jobs or make a capital investment of $2,000,000 or more at the service location.

Existing Customer Criteria

- Increase billing demand by 250 kW or more above the Average Billing Demand during the 12 months prior to the date of application on one metered account
- Achieve a score of 100 or greater using the following calculations:
    - Base Score = New FTEs created X 10 + Capital Investment / 10,000
    - Load Multiplier = Estimated Load Increase (kW) / Base Average Billing Demand (Maximum of 1.0)
    - Final Score = Base Score X Load Multiplier.

Customer Account Status	Final Score	Discount Percentage on Total Non-Fuel Bill				
		Years 1 - 4	Year 5	Year 6	Year 7	Year 8
New	--	12.0%	9.0%	6.0%	3.0%	0.0%
Existing – Higher	> 200	6.0%	4.5%	3.0%	1.5%	0.0%
Existing – Lower	100 - 200	4.0%	3.0%	2.0%	1.0%	0.0%

Siting with Generation

As part of large load facilities procuring low energy costs, some are locating themselves near the power sources to ensure availability of low-cost energy. Not only are consuming companies looking to site near low-cost generation, but so are utilities. Several coal power plants have been revived or experienced increased run time in order to support new large loads.

[39]Indiana Michigan Power, Indiana Economic Development Rider 2, https://www.aep.com/assets/docs/economic-development/IN-EDR-2023-App.pdf.

While there is an option to build new generation, co-locating the data center or cryptocurrency facility with an existing coal or gas plant slated for retirement or transition to a gas-fired plant can be an attractive energy source for larger users. This can result in increased greenhouse gas emissions and local air and water pollution due to smaller, less efficient plants being built or from the proliferation of coal-fired plants that may have difficulty with emission compliance. Additionally, while some large loads are considering nuclear power sources, there are concerns about capacity limitations and increased wholesale market prices if such power plants dedicate power directly to a customer rather than to the open market.

Including Projected Loads in Forecasts

Prospective data load centers and cryptomining facilities are seeking the best electricity rates and terms. This can result in utilities over-forecasting new load additions and capacity needs. Inclusion of the loads into utility forecasting needs a level of certainty as to whether a project will move forward or not, and sensitivity analyses need to properly account for the level of load that may not come to fruition. A utility's capacity planning cycles will likely never match up with discussions of potential customers' loads. Therefore, utilities should assess the likelihood of the load addition using elements such as where the new load is in the interconnection process, whether a feasibility study has been conducted, and whether the location has been procured, such as through a land sale/lease contract or local zoning approval.

Providing reasonable estimates of large new loads is extremely important, as it can require investment in not only new generating capacity, but also the transmission and distribution systems. If utilities utilize their planning processes, such as integrated resource planning ("IRP"), or a regional transmission operator does long-term planning of new transmission infrastructure, those entities could invest in capacity and grid system upgrades that end up not being needed if the large loads do not come to fruition. This results in existing customers footing a bill for stranded assets and less load and fewer customers to share those stranded assets costs across.

Mitigating over- and under-building of assets ultimately resides with the utilities and their planning models.[40] The planning models themselves need to not only account for customer load growth requirements over a long-term, but they also need to assess transmission and distribution opportunities and investments in distributed energy resources, such as energy efficiency, demand response, renewable energy, and storage. With all that said, there does not seem to be a utility or transmission operator that has established a process that can properly account for large load additions. For example, in 2023, Georgia Power submitted a one-year update to its 2022 IRP filing, indicating that the utility's demand increased by 20% by 2030 compared to the prior year's filing. There was significant uncertainty among the added load, particularly as to where this projected increase in demand was in the process of

[40] *Demand Better: How growing demand for electricity can drive a cleaner grid*, Jeremy Fisher, Laurie Williams, Dori Jaffe, Megan Wachspress, Sierra Club, September 2024, https://www.sierraclub.org/sites/default/files/2024-09/demandingbetterreportfinal_sept2024.pdf, p. 24, accessed October 18, 2024.

being interconnected. Transparency regarding potential new loads in the planning process—including the timing of the interconnection process and feasibility studies and ramp up of load over time—can be beneficial in ensuring sufficient investment in capacity.

Adequate Available Capacity

Kentucky Power's Economic Development Rider ("EDR") tariff requires there to be sufficient capacity to accommodate the increased or new load proposed by the customer. If sufficient capacity is not available, the cost of capacity to serve the new load must be passed on to the customer, by decreasing the discounted rate received by the customer. This provision is made to ensure that if capacity is needed to serve the load, that those costs are not passed on to the existing ratepayers. Not limited to EDRs, tariffs can include limitations on the level of load served by a certain tariff, such as Idaho Power Company's Schedule 20 Speculative High-Density Load.[41]

Tariff E.D.R.
(Economic Development Rider)

Terms and Conditions

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non- discounted tariff demand charge. The reduction will be applied in reverse chronological order

Conclusion

An ideal tariff will limit risk based upon the load being added to the system. There are several ways to achieve this and therefore, there is not one uniform set of safeguards that should be established. However, at a minimum, tariffs or special contracts should include the following:

1. For large loads under 50 MW, contract terms are not longer than 10 years, and loads larger than 50 MW should consider longer contract terms such as 12-20 years. Either contract term should come with pricing and negotiation terms set intermittently throughout the overall contract term.
2. Minimum or tiered monthly load requirements to qualify for the tariff.
3. Penalties for not maintaining a good load factor (typically 85% or greater) or power factor (typically 90% or greater). Examples of this are provided in Table 1 above.
4. Establish minimum demand charges or a demand ratchet to ensure that a large customer's fixed charges for peak demand levels are recovered.
5. Identification of costs that should be assigned to the customer or the requirement for a bond or deposit to offset the cost risk to existing ratepayers. Requirement of

[41] Idaho Power Company Schedule 20 Speculative High-Density Load: https://docs.idahopower.com/pdfs/AboutUs/RatesRegulatory/Tariffs/20.pdf.

contributions in aid of construction for any grid upgrades related directly to providing service will offset potential for stranded assets costs.

6. To ensure that the large load customer is not being subsidized by the service territory's other customers, the utility should track costs and revenues from the large load customer and assess a true up mechanism if the revenues do not exceed the customer costs.
7. An interruptible service requirement that can be negotiated between the utility and the customer. An interruptible service agreement should include the number of events and total annual hours, length of events, load reduction requirement, and penalty payment for failure to respond. It should also have term limits to allow for renegotiation.
8. Adequate available system capacity, with a requirement for procuring new capacity to be backed by the customer or through the purchase of renewable energy.

While these elements can be considered as part of any tariff related to serving large loads that may be considered volatile or a significant impact to the system, these terms will vary based upon the service territory's characteristics and current ratepayers.

In addition to establishing safeguards in tariffs, utilities need to put forward reasonable forecasts which consider whether large loads will move forward to interconnection. As part of those forecasts, utilities and IRPs should take into consideration how large loads can be served by a variety of services including transmission and distribution upgrades and investments in distributed energy resources. Using distributed energy resources such as solar, storage, and energy efficiency can also assist utilities and states to meet their environmental goals.

State	Utility	Document Type	Link	Contract Length	Minimum Demand	Minimum Load Factors	Range for Power Factor	Requirements for Investment
Wyoming	Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy	Special Contract	https://ir.blackhillscorp.com/static-files/5c33d769-2d19-43f8-8898-a37af25481ef#:~:text=This%20tariff%20is%20applicable%20to,Agreement")%20with%20the%20Company.	Min 2 years; renogotiation at least every 3 years	10,000 kW	N/A	N/A	New electric infrastructure, line extension or system upgrades
Arkansas	Entergy Arkansas LLC	Tariff	https://cdn.entergy-arkansas.com/userfiles/content/price/tariffs/eal_lphlds.pdf	N/A	N/A	N/A	N/A	Security deposit equal to 3 months of average estimated bill. Contributions in Aid of Construction for all network upgrades. Security Bond equal to Value of Lost Load Per MISO Schedule 28
Idaho	Idaho Power Company	Tariff	https://docs.idahopower.com/pdfs/AboutUs/RatesRegulatory/Tariffs/20.pdf	Special Contract required for over 20,000 kW	1,000 kW	N/A	90% or greater	Upgrades for interconnection facilities
New York	New York Municipal Power Agency	Tariff	https://ets.dps.ny.gov/ets_web/search/showPDF.cfm?%3B%3AIS%20%3B%2A%29LOUNWD%5CJ%5E8%2B"%2B5%2F0MD%2F0%28%231V%28S<WX%0A	N/A	>300 kW or load density exceeds 250/kWh/ft^2/year	N/A	N/A	Feasibility study, entire cost of new facilities necessary to supply requested service, cash deposit or Letter of Credit
South Dakota	Montana-Dakota Utilities Company	Tariff	https://puc.sd.gov/commission/Tariffs/Electric/mdu/Section3/20.pdf	3-5 years	10,000 kW	85%	Between 97% lagging and 97% leading	No
Washington	Grant County Public Utility District	Tariff	https://www.grantpud.org/templates/galaxy/images/Rate_Schedule_No_17.pdf	N/A	No minimum- separatedby greater or less than 200 kW	N/A	N/A	No
Indiana	Indiana Michigan Power	Tariff	https://www.aep.com/assets/docs/economic-development/IN-EDR-2023-App.pdf	N/A	500 kW	N/A	N/A	Create at least 20 full-time equivalent jobs or make a capital investment of $2 million or more at the service location, must apply and receive economic development assitance from the state, local government, or other public agency
Kentucky	Kentucky Power	Special Contract	https://psc.ky.gov/tariffs/Electric/Kentucky%20Power%20Company/Tariff.pdf	10 years	500 kW	N/A	N/A	N/A
Missouri	Evergy Missouri Metro	Tariff	https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/special-high-load-factor-market-rate.pdf	No more than 10 years, with pricing terms no more than 5 years	100,000 kW/month or projected to be 150,000 kW within 5 years of being a new customer	85% or greater	N/A	N/A
North Dakota	Montana-Dakota Utilities Company	Tariff	https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/NorthDakota/Electric/NDElectric38.pdf	3-5 years	10,000 kW	85%	Between 97% lagging and 97% leading	N/A

State	Utility	Cost Assignment	Requirement to Shed Load	Load Subject to Interruptible Service	Maximum Hours of Interruptible Per Year	Demand Response	Requirement for Renewables or Traditional Generation	Requires Adquate Available Capacity	Notes
Wyoming	Cheyenne Light, Fuel and Power Company d/b/a Black Hills Energy	N/A	As defined in contract	As specified in contract	As specified in contract	No	No	N/A	
Arkansas	Entergy Arkansas LLC	N/A	Yes	Non-firm demand	40 or 80 hours	N/A	N/A	N/A	
Idaho	Idaho Power Company	N/A	Yes	Unclear	225 hours	N/A	N/A	Yes	
New York	New York Municipal Power Agency	Purchased Power Adjustment and Rate Statement	No	N/A	N/A	Not Offered	N/A	N/A	
South Dakota	Montana-Dakota Utilities Company	No	Yes	Specified in electric service agreement	200 hours	N/A	N/A	N/A	
Washington	Grant County Public Utility District	No	No	N/A	N/A	Customer by Customer Basis	N/A	N/A	Classified as an "Evolving Industry"
Indiana	Indiana Michigan Power	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Economic Development Rider. Requires that the customer provide to the Company's satisfaction that absent the availability of the ridre, the new or increased demand would be located out of the Company's service territory or not place into service.
Kentucky	Kentucky Power	N/A	Yes	Specified in electric service agreement	N/A	N/A	N/A	N/A	Economic Development Rider
Missouri	Evergy Missouri Metro	Revenues must exceed costs	No	N/A	N/A	Special Interruptible Contract	A Schedule MKT Customer shall be subject to any future RESRAM charges imposed by Evergy Metro unless a Schedule MKT customer does have renewable attributes supporting its load greater than or equal to the then existing Renewable Energy Standard including any solar portfolio requirements.	N/A	
North Dakota	Montana-Dakota Utilities Company	N/A	Yes	Specified in electric service agreement	200 hours	N/A	N/A	N/A	

MARKET
Market and Retail-rate Knowhow for the Energy Transition

Distributed Energy, Utility Scale:
30 Proven Strategies to Increase VPP Enrollment

December 2024

Ryan Hledik (Brattle)
Akhilesh Ramakrishnan (Brattle)
Serena Patel (Brattle)
Andy Satchwell (Berkeley Lab)

Brattle

BERKELEY LAB
Lawrence Berkeley National Laboratory

Notice

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The work described in this study was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The authors would like to thank Paul Spitsen (EERE) for supporting this work and for his input to the study. For thoughtful feedback on an earlier draft of this study, we thank Robert Margolis (NREL), Stacy Miller (DOE), and Sonali Razdan (DOE). Any remaining errors or omissions are our own.

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Additionally, we thank the following individuals and organizations for sharing their expertise and experience, which served as the foundation for the insights in this report:

1. **Arizona Public Service:** Bruce Brazis, Jason Delaney
2. **CPower:** Amy Nunnemacher, Glenn Bogarde
3. **Duke Energy:** Stacy Phillips
4. **EnergyHub:** Michael Haber
5. **ev.energy:** Keenan Taylor, Scott Dimetrosky, Bill LeBlanc
6. **Green Mountain Power:** Kristin Carlson
7. **National Grid:** Paul Wassink
8. **OtterTail Power:** Jason Grenier, Babatunde Adegbesan
9. **PacifiCorp:** William Comeau
10. **PG&E:** Neda Assadi, Kendrik Li, John Hernandez
11. **RenewHome:** Cliff Staton, Melissa Caldwell
12. **Uplight:** Gisela Glandt, Courtney Staufer, Sam Harnett
13. **Voltus:** Jared Satrom, Emily Orvis
14. **WeaveGrid:** Mathias Bell
15. **Xcel Energy:** Andrew Ryan, Meagan Madden

Table of Contents

1. Summary

The need – and opportunity – to scale VPPs now

Rapidly growing electricity demand: After decades of low or declining growth in electricity demand, the U.S. now faces a significant near-term need for new generation capacity and transmission and distribution infrastructure. The investment need is driven by expected load growth from data centers, advanced manufacturing, and electrification of heating and transport, among other sources.

Limitations of conventional electricity supply: While conventional sources of electricity supply will play an important role in addressing growing demand, they are unlikely to fully bridge the gap. Constraints include equipment shortages, interconnection delays, affordability concerns, and decarbonization policy requirements.

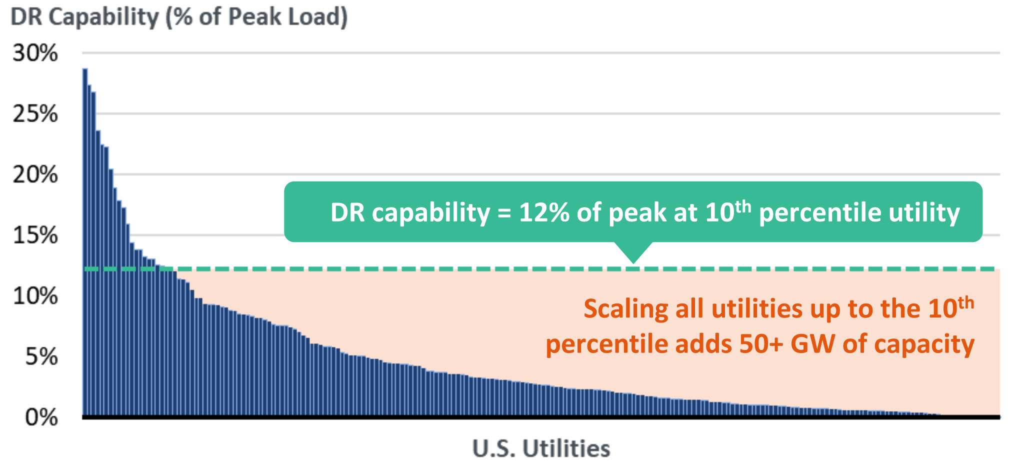
An opportunity to scale VPPs: Research has shown that Virtual Power Plants (VPPs) have the potential to provide the same resource adequacy benefits as conventional resources, at a fraction of the cost. In some cases, utilities and aggregators already have reached significant scale in VPP deployments, primarily in the form of conventional demand response (DR). This opportunity will grow as consumers continue to adopt DERs and flexible end-use technologies. However, the scale of current VPP deployment currently varies widely across jurisdictions *(see sidebar).*

30 actionable strategies: Based on in-depth interviews with VPP solutions providers that have achieved considerable scale or rapid growth in program deployment, this study provides 30 proven strategies for scaling VPPs through increased enrollment.

The Missing Megawatts

There are many successful large VPP programs in the U.S. The top 10% of U.S. utilities have the capability to reduce their system peak demand by over 12%. However, the remaining 90% of utilities have significantly less DR capability. Assuming similar performance rates, in the aggregate those utilities could add **50+ GW of capability.**

2022 DR Capability of Each U.S. Utility



Source: Brattle analysis of data from Form EIA-861 2022. The 50+ GW opportunity to scale is estimated as the additional capacity that would result from all analyzed utilities scaling capability to 12% of their peak load. The analysis includes the 214 utilities that: (i) reported DR capability to EIA in 2022, (ii) reported peak demand of at least 100 MW, and (iii) are investor-owned, municipal, cooperative, state, or federal utilities. 12 utilities are excluded due to data anomalies.

Learning from VPP offerings that have scaled

We conducted in-depth interviews with 15 VPP solutions providers (i.e., utilities and aggregators) that have reached high levels of enrollment.

The interviews

Interviews focused on key learnings related to marketing programs to customers, setting up the enrollment process, designing customer incentives, engaging and retaining customers in the program, and leveraging ecosystem partners for program success. We supplemented the interviews with a review of the literature on practices for enrolling and engaging customers in demand-side programs.

The interviewees

Interviewees were selected to broadly and comprehensively account for variation in the type of distributed energy resource (DER) being controlled, the geographic coverage of their key markets, their target customer segments, the type of organization (e.g., utility versus aggregator), and whether their focus is on wholesale or retail markets. All interviewees have developed large portfolios of DR or VPP programs, and/or had success in quickly scaling emerging program offerings *(see sidebar)*.

Feasibility and impact

Interviewees were also asked to provide a relative assessment of each VPP strategy's (1) likely impact on enrollment and (2) ease of implementation.

Examples of success in scaling VPPs

A few successes among interviewees:

- Otter Tail Power, an investor-owned utility in Minnesota, can **reduce its system peak demand by 15%** through a portfolio of demand response programs. The programs are utilized regularly for both economic and reliability benefits.
- In Ontario, Canada, EnergyHub enrolled 100,000 smart thermostat customers to build a 90 MW VPP in **only six months**.
- In Xcel Energy's Northern States Power service territory, **over half of all eligible residential customers** are voluntarily enrolled in some form of air-conditioning load control, with plans for future growth.
- Green Mountain Power has roughly 70 MW enrolled in its VPP program, making it **Vermont's largest single peaking power source.**
- RenewHome claims to have built North America's largest residential VPP, at **3 GW,** with a goal of 50 GW by 2030.

30 proven strategies to increase VPP enrollment

Marketing

1. Concisely message program benefits
2. Mention multiple motivators for participation
3. Deploy top-of-funnel marketing
4. Host in-person promotional events

Enrollment Process

5. Create a seamless enrollment process
6. Pre-enroll devices sold on utility marketplaces
7. Offer point-of-sale enrollment at retailers
8. Offer easy enrollment in multiple programs
9. Integrate value-add services into programs
10. Provide referral incentives

Ecosystem Partners

11. Harmonize messaging from utilities and OEMs
12. Engage customers through trusted entity
13. Partner with local installers
14. Exchange learnings with other utilities

Incentive Design

15. Maximize the financial incentive
16. Ensure customer pays a portion of device cost
17. Offer ongoing participation payments
18. Bundle device financing options with programs
19. Align price signals
20. Offer active and passive control models

Engagement and Retention

21. Improve program design over time
22. Regularly remind customers of their rewards
23. Compensate through channels customer will notice
24. Communicate societal impact of participation
25. Call regular testing events
26. Offer easy unenrollment
27. Offer flexibility to opt out of events
28. Limit event notifications in automated programs
29. Allow customers to set control range
30. Offer technology choice where available

30 Strategies: Impact and Ease of Implementation

Based on perspectives of VPP solutions providers

Note: The feasibility and impact scores for Strategy 18 reflect the views of the authors because it was not included in the survey.

Next Steps

Recommendations for regulators

- Use the strategies identified in this report as a checklist when reviewing existing VPP programs or proposals for new programs.
- When evaluating proposals for VPP pilots, consider requiring that the proposals also include a plan to scale the program following successful implementation of the pilot.
- Review and address areas where existing regulations may limit successful implementation of certain strategies. E.g., ensure full value stack is included in cost-benefit tests and incentives.

Recommendations for utilities

- Benchmark existing VPP program design against the strategies and identify gaps where relevant.
- Clearly define potential utility system and ratepayer benefits when requesting VPP budget increases to implement the strategies, including how higher VPP program enrollment will scale benefits.
- Streamline the enrollment process. This emerged as a key success theme in several interviews and was ranked as the highest impact strategy.

Recommendations for third party VPP aggregators

- Work together to identify and advocate for solutions to mitigate implementation barriers.
- Develop empirical support for the efficacy of the identified strategies through credible evaluation of existing VPP offerings, to convince regulators and utilities to enable them.
- Improve the likelihood of acceptance of the strategies identified in this report by delivering on commitments to scale VPPs when implementing them.

AREAS FOR FURTHER RESEARCH

Regularly review and update best practices in VPP enrollment, in order to keep up with emerging and successful approaches in a rapidly evolving VPP market.

Extend the research scope beyond methods for increasing consumer participation in VPP programs, to also identify successful practices for addressing regulatory, technical, and economic barriers.

Consider international experience, particularly innovative approaches that are beginning to emerge in Europe related to EV managed charging.

2. Introduction

Background

Maintaining power system resource adequacy in the new era of rapid load growth will require major investment.
Between 2016 and 2023, nearly $100 billion was invested in U.S. power generation capacity primarily for the purposes of resource adequacy. From 2023 to 2030, that investment need is expected to triple. Conventional sources of generation capacity likely cannot address this need alone *(see next page)*.

Virtual Power Plants (VPPs) are an emerging resource that already provides significant value.
Recent studies have shown that VPPs can cost-effectively contribute to resource adequacy on a similar scale as conventional resources. Several regions already have mature VPP programs and others are leveraging new technologies to develop emerging programs.

There is significant untapped potential to introduce and scale VPPs in more regions.
Deployment of VPPs is uneven across U.S. utilities, with the leaders having significantly larger portfolios than most other utilities. Learning from the strategies that large VPP programs have used to achieve scale can quickly expand VPP capacity across the U.S.

This study provides actionable strategies for scaling VPP programs and capabilities.

We identified 15 organizations across the U.S. that have developed VPP programs that are rapidly emerging or have reached significant scale. We interviewed them to identify common practices that have contributed to that success, with a focus on enrollment. The strategies and associated real-world examples provide a checklist for optimizing the design of both emerging and established programs.

What is a VPP?

The U.S. DOE recently defined VPPs as "aggregations of distributed energy resources (DERs)… that can balance electricity demand and supply and provide utility-scale and utility-grade grid services like a traditional power plant."

For the purposes of this report, we include traditional demand response (DR) within our definition of a VPP. We consider both **emerging resources** such as behind-the-meter batteries, as well as **established programs** such as air-conditioning load control, which provide tens of gigawatts of demand reduction capability currently.

While not explicitly defined as a VPP in this report, demand-side measures that provide passive, beneficial changes in load shape, such as energy efficiency and distributed solar, also will be highly valuable contributors to the energy transition.

U.S. generation capacity outlook: Mind the gap

U.S. electricity demand is projected to accelerate enormously through the end of the decade. Traditional generation resources are unlikely to bridge the supply gap due to several constraints. Innovative new solutions are needed.

	2016 to 2023 (Historical)		2023 to 2030 (Forecast)	
Demand: Peak Load Growth	(+3%) 24 GW	**Limited growth** • Overhang from 2009 recession • Efficiency improvements • Decoupling of GDP and electricity demand	(+14%) >100 GW	**Significant load growth** • Data centers • Building electrification • Electric vehicles • Advanced manufacturing
Supply: Needed Investment in Capacity for Resource Adequacy	$90 billion 83 GW	**Persistent investment despite limited demand growth** • Coal replacement • Renewables integration • Increasingly volatile weather	$250-$350 billion ~240 GW	**Likely infeasible with traditional generation resources** • Equipment shortages • Interconnection delays • Affordability concerns • Decarbonization constraints

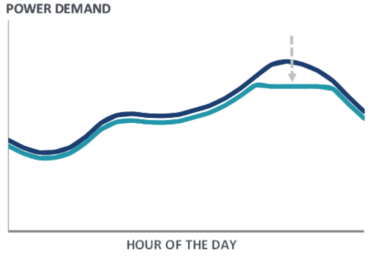
Innovative solutions are needed to address supply/demand gap

Note: See appendix for sources and assumptions.

Benefits of VPPs

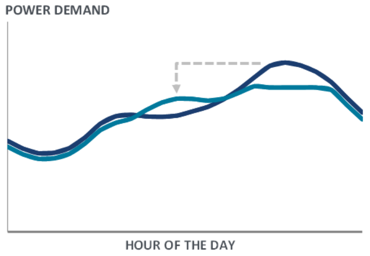
VPPs provide many operational benefits, along with the potential to mitigate other concerns such as lengthy resource interconnection delays and unprecedented uncertainty in load forecasting.

Sources of VPP Operational Value



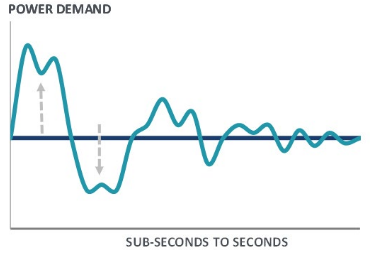
Peak demand reduction

Dispatchable and event-based, with a limited number of events per season. Primarily provides capacity value.



Load shifting

Occurs frequently. Provides capacity and energy value, and potentially GHG emissions reductions. Helps to integrate renewables by reducing curtailments.



Real-time grid balancing

Some VPPs elements, such as batteries or grid-interactive water heaters, can provide ancillary services to address real-time imbalances on the grid.

Speed and Flexibility of VPPs

	Supply-centric approach	VPP-centric approach
Resource development timeline	Transmission-connected resources constrained by 4+ year interconnection approval process	VPPs can be "built" as quickly as customers enroll and the required control software is implemented
Resource development flexibility	Investments in traditional capacity are a 20-40 year commitment once steel is in the ground	VPPs can scale as demand grows and, to an extent, downsize if needed

Other Sources of VPP Value

VPPs can provide other benefits as well, such as:

- Avoided infrastructure buildout
- Increased renewables deployment
- Better power system integration of electrification
- Enhanced customer satisfaction
- Improved behind-the-meter grid intelligence
- Overall energy savings
- Improved resilience

Additionally, VPPs are the only resource that pays customers to participate in the energy transition.

For further discussion, see Real Reliability: The Value of Virtual Power and Power Shift.

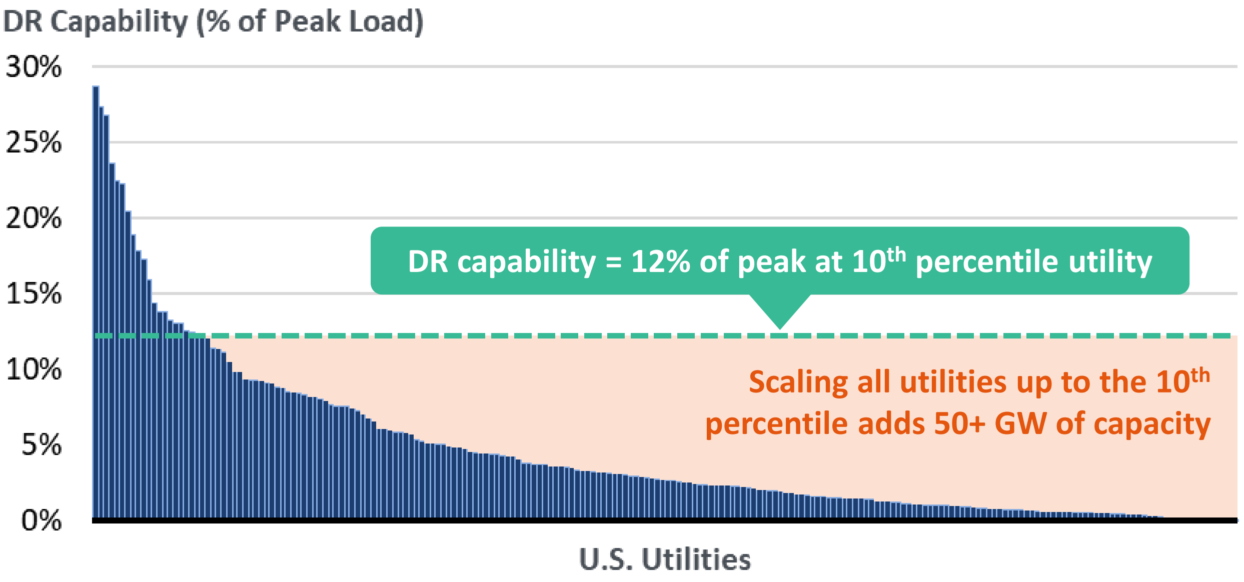
Significant untapped potential for VPPs

There is around 30 GW of existing DR capability at U.S. utilities, and the top 10% of U.S. utilities have the capability to reduce their system peak demand by over 12%. If the remaining utilities reach a similar level of success by adopting the practices described in this report, it would add over 50 GW of new capacity to the U.S. power system.

The scale and impact of this opportunity is substantial in the context of the impending capacity supply-demand gap.
50 GW is half of the 100 GW of U.S. peak demand growth projected through 2030. Further, the sources of new load are new opportunities for flexibility, creating significant additional VPP potential that is incremental to the 50 GW.

The characteristics of each utility's customer base and market conditions will determine the type of opportunities that can be pursued to realize the untapped VPP potential.
Some of the top utilities have significant industrial load and enroll much of their DR capability through a small number of large customers. Other top utilities have programs consisting of large numbers of residential and small commercial customers. Utility-specific characterization and assessment of potential is key to strategically pursuing VPP opportunities.

2022 DR Capability of Each U.S. Utility



Source: Brattle analysis of data from Form EIA-861 2022. The 50+ GW opportunity to scale is estimated as the additional capacity that would result from all analyzed utilities scaling capability to 12% of their peak load. The analysis includes the 214 utilities that: (i) reported DR capability to EIA in 2022, (ii) reported peak demand of at least 100 MW, and (iii) are investor-owned, municipal, cooperative, state, or federal utilities. 12 utilities are excluded due to data anomalies.

Study objective and approach

This study provides actionable strategies for scaling VPP programs and capabilities, based on methods that are proven to be effective through existing offerings.

We conducted interviews with 15 VPP solutions providers across the US offering programs that are rapidly emerging or have reached significant scale. We identified strategies that have contributed to that success with a specific focus on methods for increasing customer enrollment. Interviewees were also asked to rank each strategy's relative ease of implementation and possible impact.

Study objectives:

- Provide state energy regulators with a checklist for achieving successful program enrollment.
- Provide utilities and third parties with a guide to optimize the design of new and established programs.
- Establish a broader common understanding among all industry stakeholders regarding the level of participation that may be achieved through successful program offerings.

We considered both mature demand response programs as well as emerging programs that rely on more advanced technologies. The methods that have led to the significant scale of mature demand response programs often are similarly applicable to emerging programs.

What's not in scope?

Our study is not intended to provide the following:

- **An exhaustive review of all VPP programs.**
  We focus specifically on cases that illustrate innovative approaches that have led to high levels of participation.
- **A quantitative enrollment target that utilities or third parties should be required to meet.**
  While the report will highlight what has been achieved in some jurisdictions, many market specific factors will determine what is possible for any given VPP solutions provider.
- **Commentary on wholesale market participation models.**
  We focus exclusively on practices for enrolling end-use customers in programs, not on rules for bidding the resulting demand reductions into organized wholesale markets.

3. The Interviews

Interview Background

We identified 15 successful programs across the US and interviewed the companies offering those programs to gain insights about how they increased enrollment.

Interviews focused on key learnings related to marketing programs to customers, setting up the enrollment process, designing customer incentives, engaging and retaining customers in the program, and leveraging ecosystem partners for program success. We supplemented the interviews with a review of the literature on practices for enrolling and engaging customers in demand-side programs (see “Further Reading” section of this report).

The interviewees represent a broad range of DER types, spanning diverse North American geographic regions, retail, and wholesale markets, and including different customer classes and utility types. The breadth represented by the 15 interviewees is as follows (some interviewees had multiple programs of interest):

- **Type of DER:** Smart thermostats (7), Water heaters (2), Batteries (3), EVs (3), Technology agnostic (2)
- **Geographic Coverage:** West (4), Midwest (1), Northeast (2), South (1), and 7 covering all regions.
- **Customer Segments:** Residential (7); Residential and Commercial (6), Commercial and Industrial (2).
- **Type of Utility:** Investor-owned, vertically integrated utilities (7), investor-owned transmission and distribution utilities (1), and aggregators (7).
- **Wholesale Market Participation:** No participation (4), participating in one (4), participating in multiple (7)

The Interviewees

1. Arizona Public Service
2. CPower
3. Duke Energy
4. EnergyHub
5. ev.energy
6. Green Mountain Power
7. National Grid
8. OtterTail Power
9. PacifiCorp
10. PG&E
11. RenewHome
12. Uplight
13. Voltus
14. WeaveGrid
15. Xcel Energy

Interviewees: Utilities

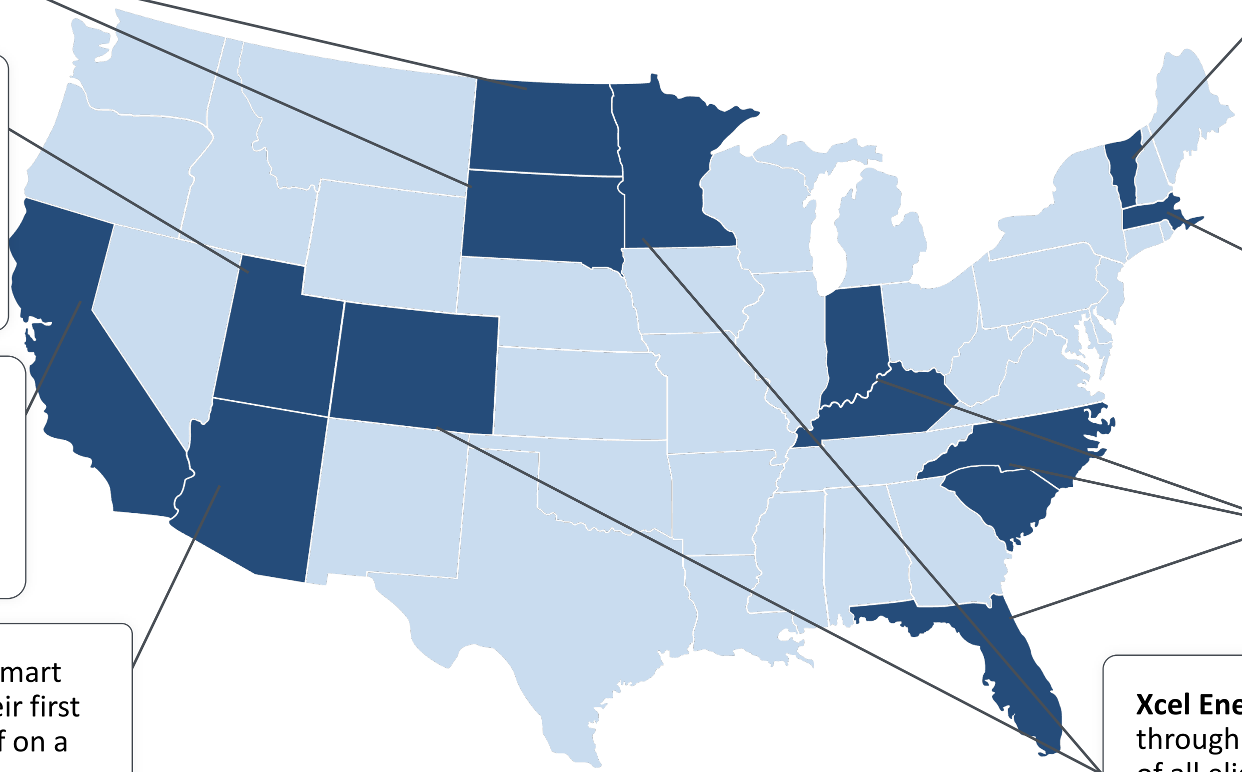
The utilities we interviewed represent a broad range of geographies, DER technologies, and market structures.

OtterTail Power's total DR capability is over 15% of its system peak demand.

Rocky Mountain Power has 560 MW of peak demand reduction capability, and 20% enrollment among all residential customers. Its battery VPP program had 27 MW enrolled as of 2024.

PG&E currently operates 20 MW of smart AC load control switches, 10 MW in a Bring Your Own Device VPP program, and 19 MW in its Emergency Load Reduction Program.

Arizona Public Service built a 150 MW smart thermostat VPP in 5 years and called their first locational event in 2024 to provide relief on a few constrained feeders.



Green Mountain Power has about 70 MW enrolled in its VPP program, making it Vermont's largest single peaking power source.

National Grid had over 2,000 residential customers (~24 MW) enrolled in the Connected Solutions battery program in MA as of the end of 2023.

Duke Energy has 16% of residential customers enrolled in A/C load control, with over 1,500 MW of capacity.

Xcel Energy has 390 MW of DR capability in MN through its A/C control programs, with over half of all eligible residential customers enrolled. Their utilities in both MN and CO are in the top 10% of IOUs by DR capability.

Note: For detail on additional successful VPP offerings, see RMI's VPP Flipbook

Interviewees: VPP Aggregators/Platforms

The aggregators and platform-providers we interviewed have large portfolios spanning North America and integrate various DER technologies.

Residential Focus

EnergyHub

1.4 million devices; 2 GW of capacity

Energy Hub helps utilities manage their smart thermostat, battery, and EV programs. In 2023 they enrolled 100,000 customers (90 MW) in Ontario's smart thermostat program in just 6 months.

RenewHome

3 GW of capacity

RenewHome helps customers manage their energy use. They work with 100+ utilities and are partnering with NRG to build a 1 GW virtual power plant in Texas.

Uplight

7.8 GW of capacity

Uplight provides utilities a platform to manage customer DERs. They worked with Consumers Energy's thermostat program to enroll 10,000 customers per week.

Commercial and Industrial Focus

CPower

7 GW of capacity

CPower helps customers manage and monetize their DERs. They have a portfolio of large customers, with 7 GW of capacity at more than 28,000 sites across the U.S.

Voltus

7 GW of capacity

Voltus helps customers manage and monetize their DERs. They have over 13,000 sites enrolled across over 60 programs to provide grid services.

Electric Vehicle Focus

ev.energy

200,000 EVs under management

ev.energy smart charging helps EV drivers optimize their charging schedules to reduce costs and carbon emissions and take advantage of off-peak rates. ev.energy has partnered with 55+ utilities across the globe and connected over 200,000 drivers, reducing peak charging load by over 90%.

WeaveGrid

Supports over 30 utilities and OEM partners

WeaveGrid leverages vehicle telematics, chargers, and utility data for managed charging and supports utilities serving more than 40% of EVs in the U.S. In 2022, it partnered with PG&E to launch the Resilient Charging Pilot, where about 5,000 EVs were provided passive and active managed charging options to enhance grid resilience.

4. 30 Strategies of Large VPP Programs

Overview of interview results

Our interviews identified 30 unique strategies that are proven to contribute to successfully scaling VPP programs.

We organized the 30 strategies into five distinct categories:

- Marketing
- Enrollment process
- Ecosystem partners
- Incentive design
- Engagement and retention

Additionally, the interviewees ranked each of the 30 strategies in terms of (1) their likely impact on enrollment and (2) their ease of implementation.

The remainder of Section 4 summarizes the findings of the interviews and strategy rankings and is organized according to the five categories noted above. The next page provides a concise overview of the results.

30 Strategies: Categories, relative feasibility, and impact

Marketing

1. Concisely message program benefits
2. Mention multiple motivators for participation
3. Deploy top-of-funnel marketing
4. Host in-person promotional events

Enrollment Process

5. Create a seamless enrollment process
6. Pre-enroll devices sold on utility marketplaces
7. Offer point-of-sale enrollment at retailers
8. Offer easy enrollment in multiple programs
9. Integrate value-add services into programs
10. Provide referral incentives

Ecosystem Partners

11. Harmonize messaging from utilities and OEMs
12. Engage customers through trusted entity
13. Partner with local installers
14. Exchange learnings with other utilities

Incentive Design

15. Maximize the financial incentive
16. Ensure customer pays a portion of device cost
17. Offer ongoing participation payments
18. Bundle device financing options with programs
19. Align price signals
20. Offer active and passive control models

Engagement and Retention

21. Improve program design over time
22. Regularly remind customers of their rewards
23. Compensate through channels customer will notice
24. Communicate societal impact of participation
25. Call regular testing events
26. Offer easy unenrollment
27. Offer flexibility to opt out of events
28. Limit event notifications in automated programs
29. Allow customers to set control range
30. Offer technology choice where available

30 Strategies: Impact and Ease of Implementation
Based on perspectives of VPP solutions providers

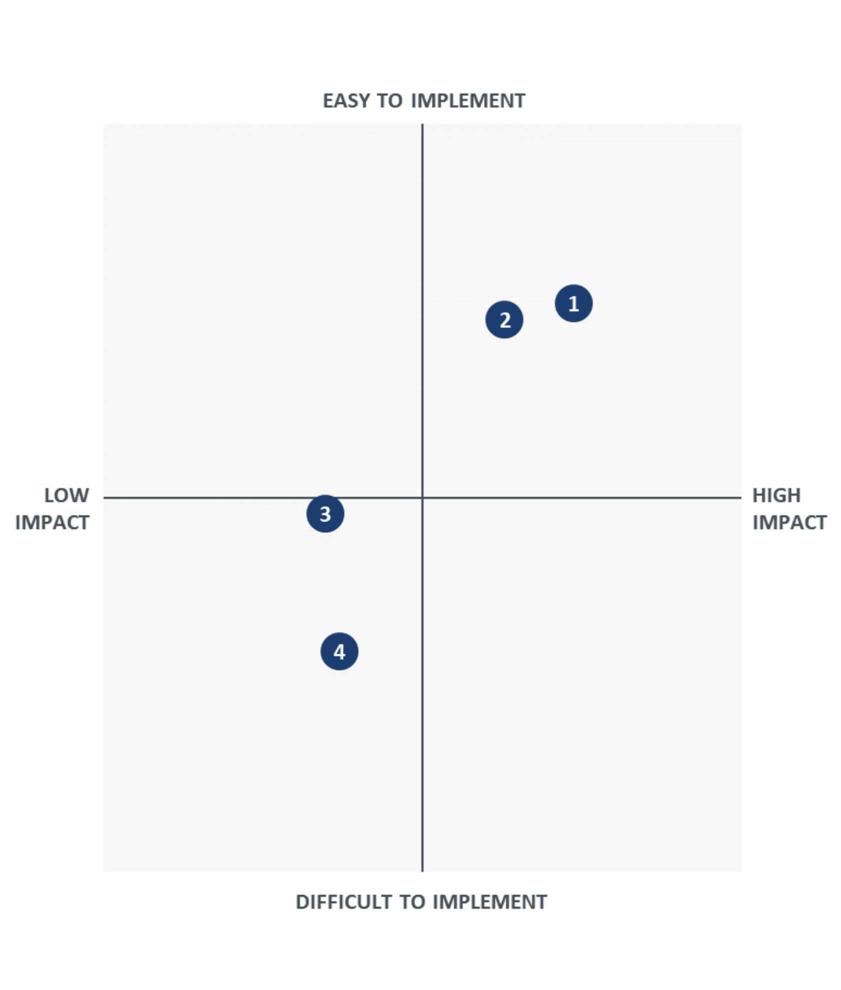
Note: The feasibility and impact scores for Strategy 18 reflect the views of the authors because it was not included in the survey.

4. 30 Strategies of Large VPP Programs

MARKETING

Marketing Strategies

1	**Concisely message program benefits**	**Deliver clear and simple messaging about the benefits of participation.** The headline benefit to highlight should generally be the financial incentive. Key program features – such as the ability to opt out or other features that add convenience – should also be clear in headline materials.
2	**Mention multiple motivators for participation**	**Develop marketing campaigns and email blasts that include messaging focused on additional motivators beyond incentives.** Additional motivators could include social/community contributions (e.g., helping the utility manage the grid and avoid outages), energy conservation and climate goals, and automation and convenience.
3	**Deploy top-of-funnel marketing**	**Develop campaigns that funnel customers toward a broad set of programs focused on a common theme, as a complement to program-specific marketing.** A popular example of top-of-funnel campaigns is "reduce-reuse-recycle". Utility themes could focus on ways to save or climate goals.
4	**Host in-person promotional events**	**Supplement other marketing channels with in-person events.** Events could be particularly useful to build trust when introducing new technologies or in regions where the energy transition is viewed negatively.



Concisely message program benefits

Strategy #1

Successful programs deliver clear and simple messaging about the benefits of participation.

The headline benefit to highlight should generally be the financial incentive. Key program features – such as the ability to opt out or other features that add convenience – should also be clear in headline materials.

Potential Impact

- Customers are more likely to enroll and develop trust in VPP programs.
- Improving customer understanding and acceptance of program terms can also reduce unexpected surprises (e.g., penalty for opting out of an event) and associated complaints.
- Concise messaging about financial benefits can also influence other important stakeholders like regulators and OEMs to support the program.

Potential Implementation Hurdles

- It can be a challenge to communicate complex program and tariff rules in an accurate but simple format. To a certain extent, program rules themselves need to be simplified before the marketing can be simple.
- Market research may be needed to fine-tune messaging to be most effective in increasing enrollment given the demographics of a specific utility territory.

Recommendation in Action:

Xcel Energy Minnesota's smart thermostat program landing page

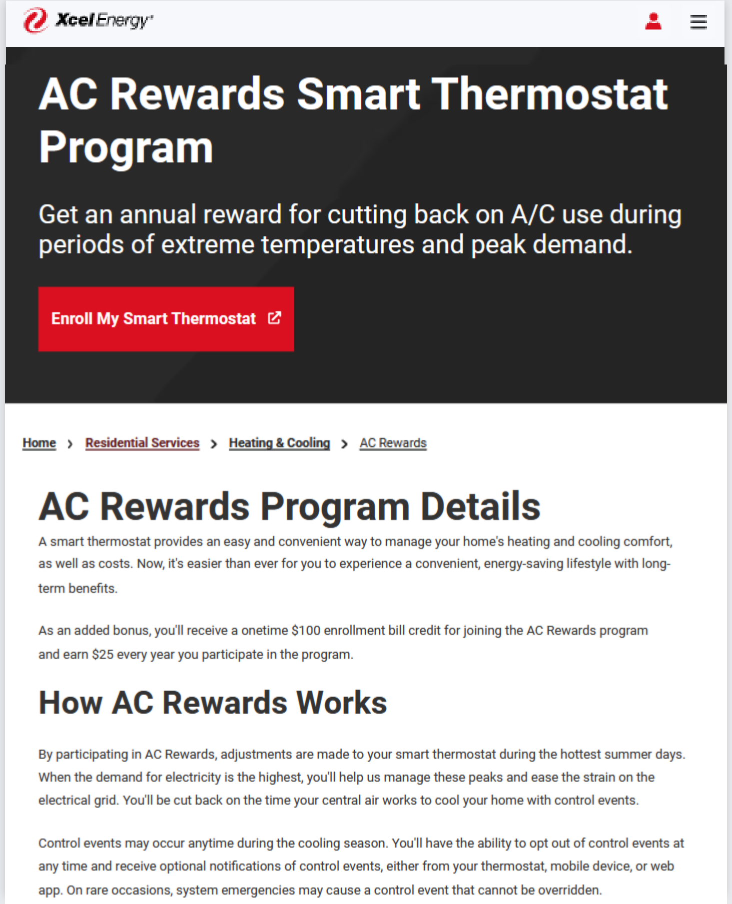


Figure Source: Xcel Energy website

Mention multiple motivators for participation

Strategy #2

Successful programs generally develop marketing campaigns and email blasts that include messaging focused on additional motivators beyond incentives.

Additional motivators could include social/community contributions (e.g., helping the utility manage the grid and avoid outages), energy conservation and climate goals, and automation and convenience

Potential Impact

- Different customer segments may be more receptive to different motivators.
- Mentioning a motivator such as convenience could preempt common concerns about certain programs; e.g., that smart thermostat programs will lead to reduced comfort during events.
- Communicating non-financial motivators also helps demonstrate the company's commitment to corporate social responsibility

Potential Implementation Hurdles

- Utilities may need to allocate additional funding to programs for developing marketing collateral, placing ads on an ongoing basis, and training staff to execute on this strategy.
- Messaging themes likely need to be refined based on local and community-level feedback from participants and non-participants about motivations for enrolling in programs.
- Delivering targeted messaging to different audiences can take more effort and resources.

Recommendation in Action:

Otter Tail Power's residential programs landing page

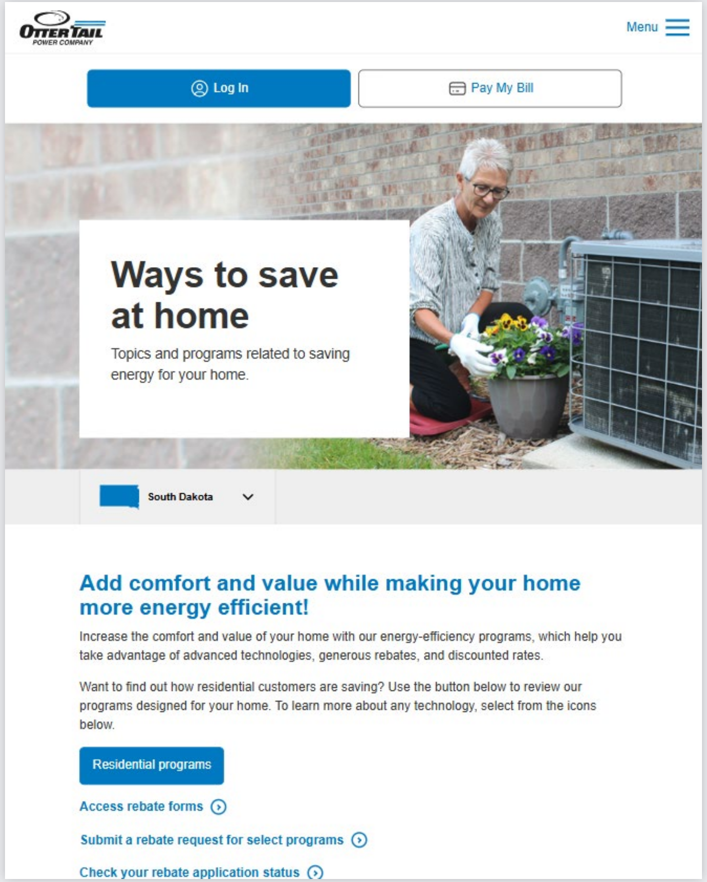


Figure Source: Otter Tail Power's website

Deploy “top-of-funnel” marketing

Strategy #3

Some utilities with large portfolios have developed campaigns that funnel customers toward a broad set of programs focused on a common theme, as a complement to program-specific marketing.

A popular example of top-of-funnel campaigns is “reduce-reuse-recycle”. Utility themes could focus on ways to save or climate goals.

Potential Impact

- Increased visibility for utility programs in general at potentially lower cost than program-specific campaigns
- Increases engagement and partnership with the broader customer base
- Improved positioning as a thought leader and trusted source of information
- Allows program-specific marketing to be more tailored and targeted because higher-level themes have been communicated in top-of-funnel campaigns

Potential Implementation Hurdles

- Finding the right message requires coordination and strategic alignment across multiple utility programs, which may be managed by different teams.
- Selecting and optimizing across the right channels (social media, email, physical ads, etc.) for top-of-funnel and program-specific marketing can be challenging.

Recommendation in Action:

ComEd’s Energy Efficiency Campaigns

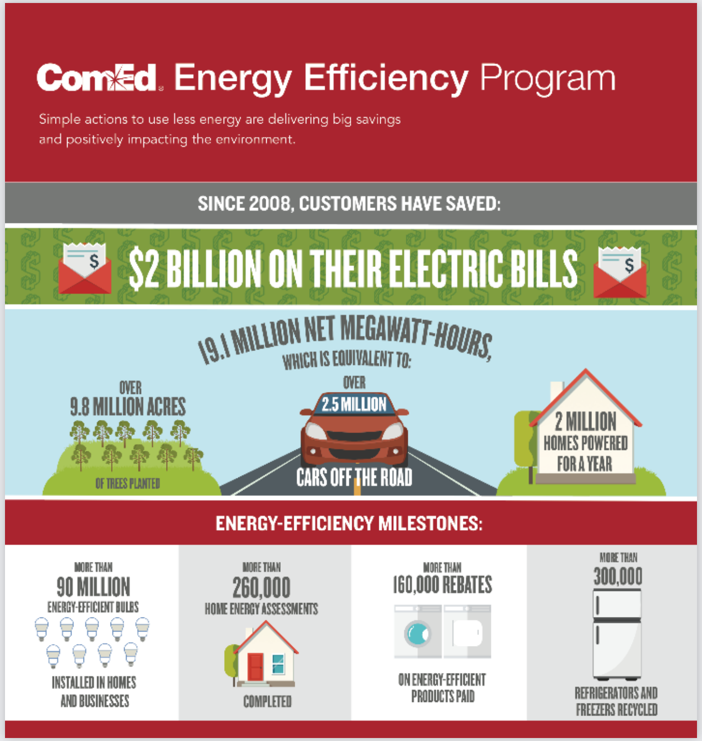


Figure Source: ComEd website

Host in-person promotional events

Some successful programs supplement other marketing channels with in-person events.

Events could be particularly useful to build trust when introducing new technologies or in regions where the energy transition is viewed negatively.

Strategy #4

Potential Impact

- Potential to target specific locations for concerted enrollment efforts (e.g., in locations that may be approaching the need for distribution upgrades).
- Ability to target customers at the point-of-sale of devices at brick-and-mortar stores (e.g., car dealerships or home improvement retailers).
- For smaller utilities, a few in-person events may be able to cover a large portion of the service territory and with more engagement than online channels.

Potential Implementation Hurdles

- In-person events are relatively high-cost and reach a much smaller audience.
- Planning, coordinating, and staffing in-person events may be prohibitively resource-intensive.
- Tracking the success of events (e.g., leads generated) can be challenging.

Recommendation in Action:

BGE EVSmart Program Kickoff Event

Bright sun and a heat index higher than 100 couldn't keep more than 150 people from celebrating EVsmart and learning how they can turn their commutes green in more ways than one.

Electric Vehicles (EVs) from BMW, Ford, Nissan, and Tesla wowed attendees during BGE's EVsmart program kick-off, an event that highlighted new BGE initiatives that make EV ownership more accessible in central Maryland. The crowd of more than 150 people also gained insights into how EVs and smart charging can promote a healthier environment while saving them money.

Figure Source: BGE Website

4. 30 Strategies of Large VPP Programs

ENROLLMENT PROCESS

Enrollment Process Strategies

5 Create a seamless enrollment process

Successful programs minimize friction in the customer enrollment process and generally avoid requiring customers to download a new app. Example strategies could be offering multiple options for user authentication, pre-populating forms with customer data, and minimizing the number of clicks and number of forms to be filled out.

6 Pre-enroll devices sold on utility marketplaces

7 Offer point-of-sale enrollment at retailers

Successful programs offer easy/default pre-enrollment of devices sold on utility marketplaces and point-of-sale enrollment at third party retailers. This could be achieved, for example, through a checkbox to indicate enrollment in the relevant VPP program when adding a device to the cart on a marketplace or retailer website.

8 Offer easy enrollment in multiple programs

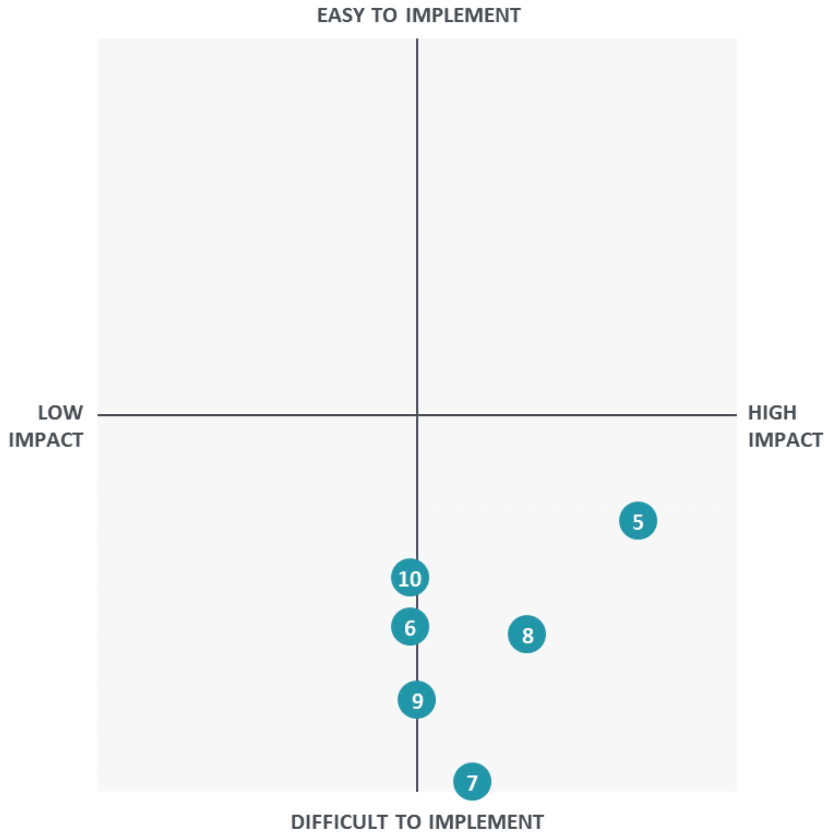
Some companies with large portfolios encourage parallel enrollment in multiple programs. For example, a customer signing up for an EV managed charging program could be prompted and directed to enroll their smart thermostat in the relevant program at the same time.

9 Integrate value-add services into programs

Some large programs integrate value-add services such as real-time consumption monitoring into the program. These services can be useful or perceived as "cool" enough to be an additional motivator for enrollment.

10 Provide referral incentives

Many successful programs offer incentives for participants to refer others to the program. Word-of-mouth can be an effective way to communicate the value of a program and ultimately increase enrollment.



Create a seamless enrollment process

Strategy #5

Successful programs minimize friction in the customer enrollment process and generally avoid requiring customers to download a new app.

Example strategies could be offering multiple options for user authentication, pre-populating forms with customer data, and minimizing the number of clicks and number of forms to be filled out.

Potential Impact

- Lower barriers to entry generally result in a direct increase in customer enrollment. Interviewees identified this as the highest impact action.
- Attract a wider audience, including those that are less tech-savvy. Reaching a more diverse customer base can enhance the program's effectiveness and inclusivity.
- Minimizes enrollment errors due to user error, reducing the number of customer support requests.
- **Further Reading**: After undergoing a redesign and eliminating 6 clicks from the enrollment process, EnergyHub saw a 70% increase in enrollment on average.

Potential Implementation Hurdles

- Collaborating with retailers and OEMs to integrate a simplified enrollment process can be challenging for VPP solutions providers, especially if they lack the scale to offer a significant value proposition to potential partners.
- Seamless integration may require data integration between different IT systems, and lack of compatibility can lead to technical complexities.
- Privacy and security must be considered when designing a more automated process that uses customer information such as addresses and meter numbers.
- Designing an intuitive and user-friendly interface for enrollment requires expertise in user experience and user interface design.

Recommendation in Action:

WeaveGrid leverages a web-based platform instead of requiring customers to download an app

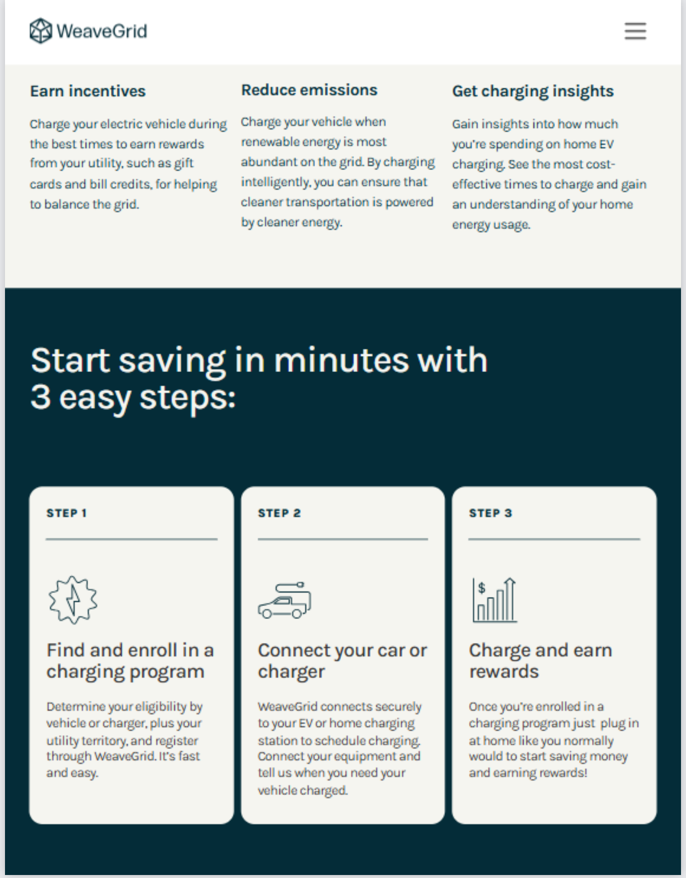


Figure Source: WeaveGrid website

Offer point-of-sale enrollment and pre-enrollment

Strategies #6-7

Successful programs offer easy/default pre-enrollment of devices sold on utility marketplaces and point-of-sale enrollment at third party retailers.

This could be achieved, for example, through a checkbox to indicate enrollment in the relevant VPP program when adding a device to the cart on a marketplace or retailer website.

Potential Impact

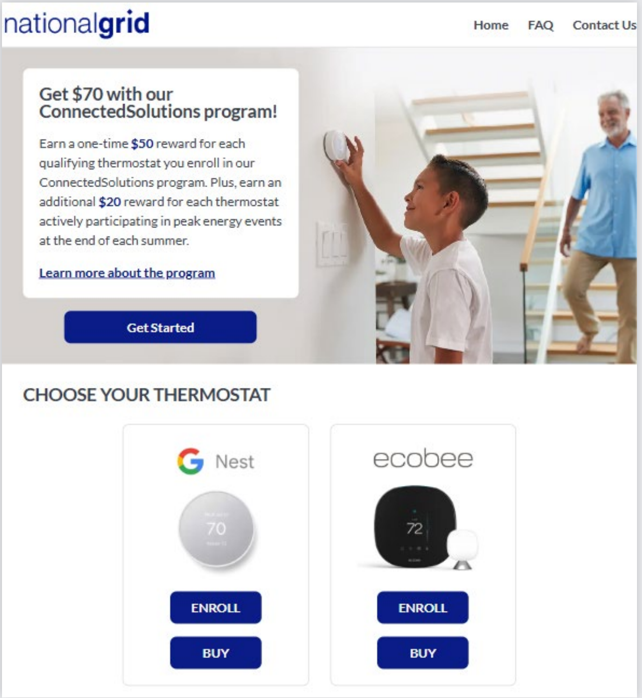
- Customers are more likely to enroll when the process is simplified and integrated into their purchase or setup experience.
- Immediate enrollment strategies can capture a wider audience, including those that might not seek out the program independently.
- Embedding the enrollment process into the existing customer interactions lowers marketing and recruitment costs.
- Habituating customers to DR events from the onset of device adoption can reduce the perceived inconvenience of participation.

Potential Implementation Hurdles

- Ensuring the pre-enrollment processes are compatible with existing platforms and retailers can be technically complex and require significant collaboration.
- Implementation requires outreach to many individual retailers. Focusing on the biggest outlets may be more feasible.
- Retail staff may need training to effectively communicate the program's benefits and enrollment process to customers.
- Customer trust must be upheld by ensuring clear communication for an opt-out option. Handling opt-out requests efficiently can add to administrative burden.

Recommendation in Action:

National Grid offers enrollment during purchase



Further Reading: By offering point-of-sale enrollment, Uplight sees a 4-5x increase in conversion rates

Figure Source: National Grid website

Offer easy enrollment in multiple programs

Strategy #8

Some companies with large portfolios encourage parallel enrollment in multiple programs.

For example, a customer signing up for an EV managed charging program could be prompted and directed to enroll their smart thermostat in the relevant program at the same time.

Potential Impact

- Bundling of multiple programs can make the overall offering more attractive by offering a much higher total incentive to prospective customers.
- Bundling multiple applicable programs together can allow program designers to leverage cross-program synergies and deliver a concise, personalized, digital customer experience.
- Bundled offerings may also yield economies of scale and lower the cost per participant.

Potential Implementation Hurdles

- It can be difficult to work across program types even within the same jurisdiction and utility due to siloed teams with limited coordination.
- Evaluating the performance and impact of bundled programs requires development of complex metrics and could lead to measurement and verification challenges.
- Ensuring the customer fully understands the value of and how to participate in multiple programs requires comprehensive education and support efforts.

Recommendation in Action:

AES Indiana used Uplight Plus to pilot an energy bundle service options

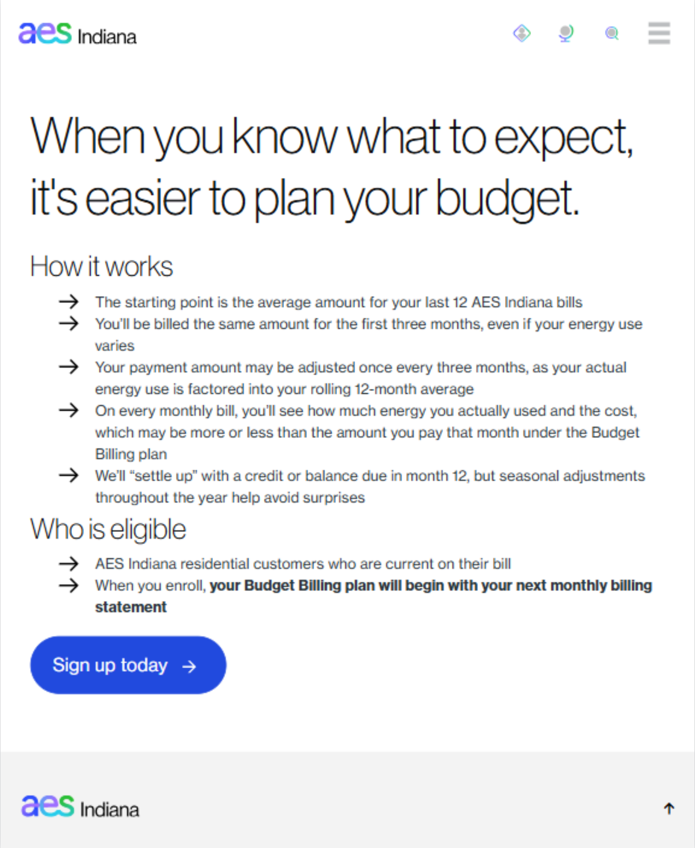


Figure Source: AES Indiana website

Integrate value-add services into programs

Strategy #9

Some large programs integrate value-add services such as real-time consumption monitoring into the program.

These services can be useful or perceived as “cool” enough to be an additional motivator for enrollment. Examples include access to a web portal with information about the customer’s energy use or packaging the VPP into a broader “subscription pricing” offer.

Potential Impact

- Integration of value-add services that cater to motivations beyond financial benefits (e.g., an emissions impact tracker) could attract a larger number of customers.
- Value-add services such as monitoring can also motivate better participation in the program.
- Showcasing additional capabilities can drive customers to more program offerings.

Potential Implementation Hurdles

- Finding and developing low-cost features that customers will find useful can be challenging.
- Integrating various technical systems and platforms used among various programs can pose technical challenges.

Recommendation in Action:

PG&E customers can view usage data in Apple Home app

Figure Source: PG&E website

Provide referral incentives

Strategy #10

Many successful programs offer incentives for participants to refer others to the program.

Word-of-mouth can be an additional effective way to communicate the value of a program, and earning referral bonuses could keep existing participants more engaged in the program.

Potential Impact

- Customers are more likely to enroll when they hear from trusted members of their communities rather than ad-based suggestions.
- Participants who refer others are likely to feel more invested in the program, increasing their loyalty and long-term engagement.
- Referral programs can foster a sense of community among participants, enhancing overall satisfaction and retention.

Potential Implementation Hurdles

- Creating rewards that are appealing enough to motivate referrals without being excessively costly can be challenging.
- Preventing fraudulent referrals and gaming of the system (e.g., self-referrals) requires robust verification mechanisms.

Recommendation in Action:

RenewHome provides incentives for referrals

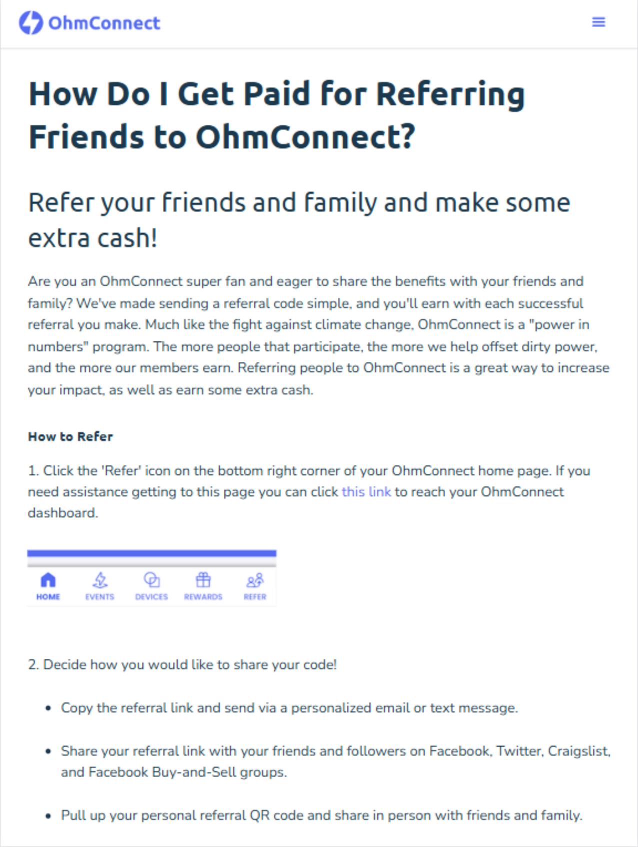


Figure Source: RenewHome website

4. 30 Strategies of Large VPP Programs

ECOSYSTEM PARTNERS

Ecosystem Partner Strategies

11 Harmonize messaging from utilities and OEMs

Several emerging programs involve partnerships with OEMs to send harmonized messaging about utility programs. Partnering with OEMs may be easier when facilitated by a third-party that handles data integration and control.

12 Engage customers through trusted entity

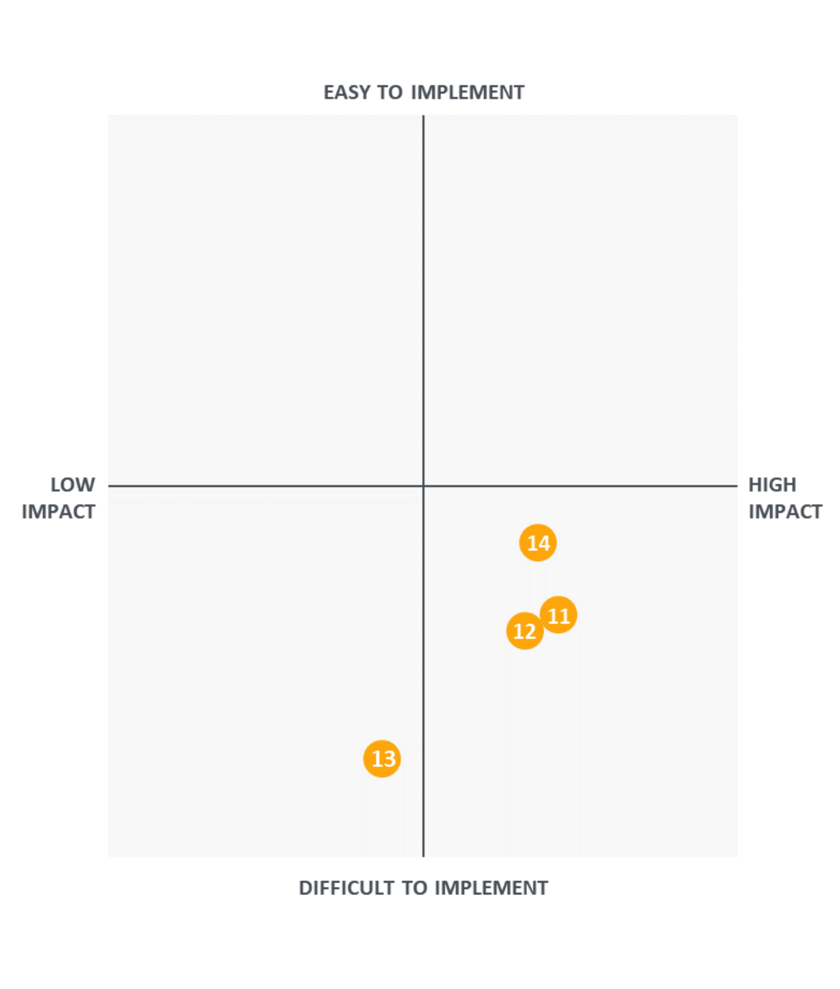
Several emerging programs are partnering with OEMs to engage, enroll, and manage customers. This can be particularly important for EV programs, where the customer may see the OEM as a better source of information about their car than the utility.

13 Partner with local installers

Successful programs have partnered with a network of local contractors to help customers install a new device through a utility program. This leverages local expertise and customer trust to streamline installation services and can also serve as an additional channel for program marketing and awareness.

14 Exchange learnings with other utilities

Successful programs leverage key learnings from ecosystem partners and utilities to accelerate program success. While there are always region-specific considerations, learning from past program design experience in other regions reduces program development costs and minimizes trial-and-error.



Harmonize messaging and engage customers through trusted entity

Strategies #11-12

Several emerging programs seeing early success are engaging with customers through partnerships with OEMs.

This can be particularly important for EV programs, where the customer may see the OEM as a better source of information about their car than the utility. Partnering with OEMs may be easier when facilitated by a third-party that handles data integration and control.

Potential Impact

- Messaging through OEMs can reduce marketing and customer acquisition costs and improve retention.
- Integration with OEMs can improve data quality and availability, program performance, and operational efficiency.
- Customers may be more likely to comply with program guidelines and DR events when they trust the entity delivering the message, leading to more reliable program performance.
- The OEM may be able to access additional device capabilities useful to programs.

Potential Implementation Hurdles

- Accurately identifying which entities customers trust the most can be difficult and can vary among customer segments.
- Establishing partnerships between the trusted entities can involve complicated negotiation and coordination.
- Data sharing and integration can be technically challenging or expensive.
- Partnership and integration can be resource-intensive, and OEMs may not prioritize partnering with every utility unless processes are standardized.

Recommendation in Action:

WeaveGrid partners with OEMs on utility managed charging programs.

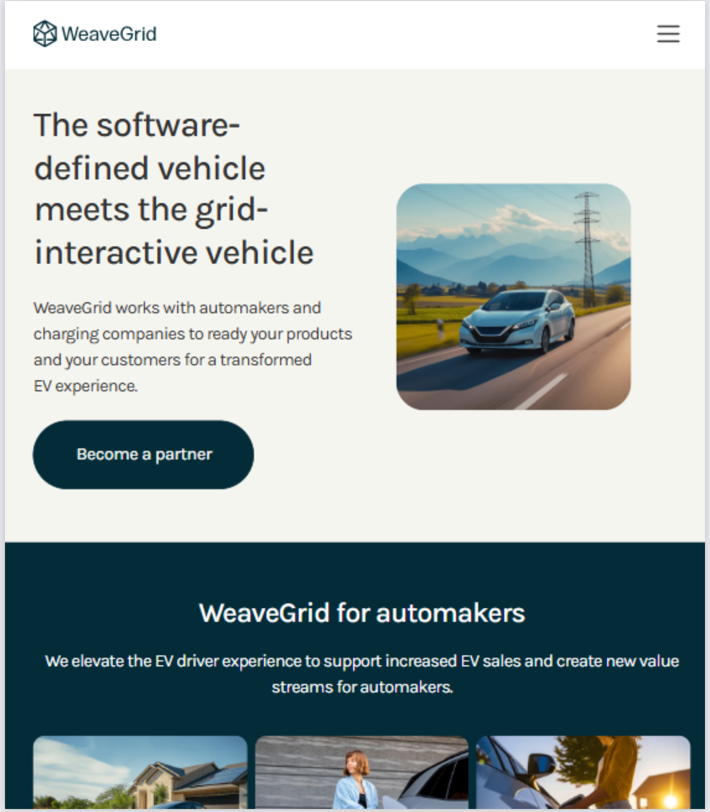


Figure Source: WeaveGrid website

Partner with local installers

Strategy #13

Successful programs have partnered with a network of local contractors to help customers install a new device through a utility program.

This leverages local expertise and customer trust to streamline installation services and can also serve as a point-of-scale channel for program marketing and awareness.

Potential Impact

- Installer partners can be especially important for battery programs, which can leverage the existing relationships and knowledge of solar installers.
- Streamlining the installation process can reduce customer costs and effort associated with joining a program.
- Offering a combined solution for solar and battery installations can be more convenient for customers.
- Partner installers may begin recommending enrollment to more customers.

Potential Implementation Hurdles

- Accurately identifying which entities customers trust the most can be difficult and can vary among customer segments.
- Establishing partnerships between the trusted entities can involve complicated negotiation and coordination.
- Data sharing and integration can be technically challenging or expensive.
- Partnership and integration can be resource-intensive, and OEMs may not prioritize partnering with every utility unless processes are standardized.

Recommendation in Action:

National Grid's Connected Solutions program links customers to approved battery storage partners/installers.

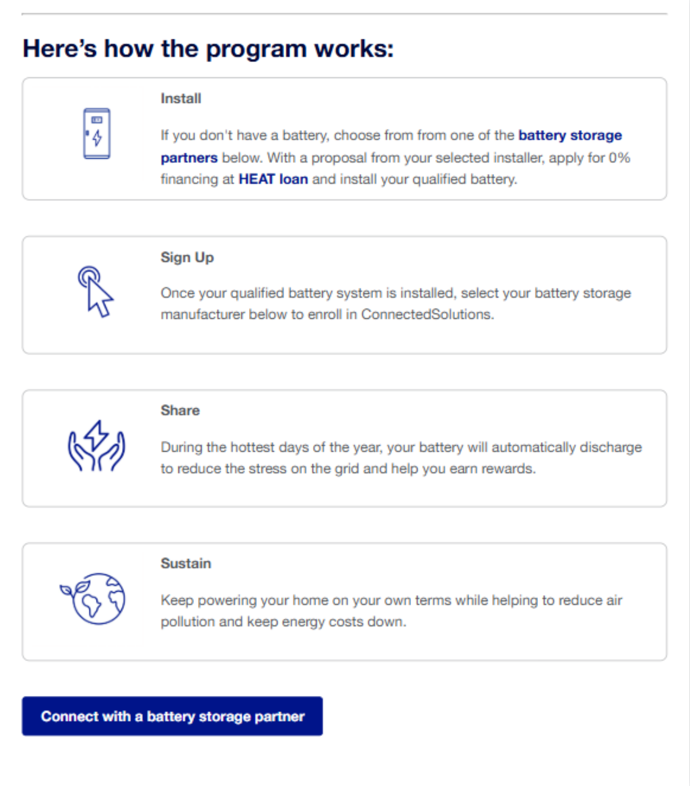


Figure Source: National Grid website

Exchange learnings with other utilities

Strategy #14

Successful programs leverage key learnings from ecosystem partners and utilities to accelerate program success.

While there are always region-specific considerations, learning from past program design experience in other regions reduces program development costs and minimizes trial-and-error.

Potential Impact

- Faster and more efficient scaling of new programs based on learnings of the first movers.
- Adopting best practices allows utilities to benchmark their performance against industry standards, identifying areas for improvement and setting realistic performance goals.
- Industry collaboration and innovation can accelerate the development of new technology and approaches.
- Sharing experiences can inform regulatory bodies and policymakers, potentially leading to a more favorable policy environment for programs.
- Access to a wider pool of knowledge and experiences allows for more informed decision-making and proactive problem-solving, reducing risks associated with new initiatives

Potential Implementation Hurdles

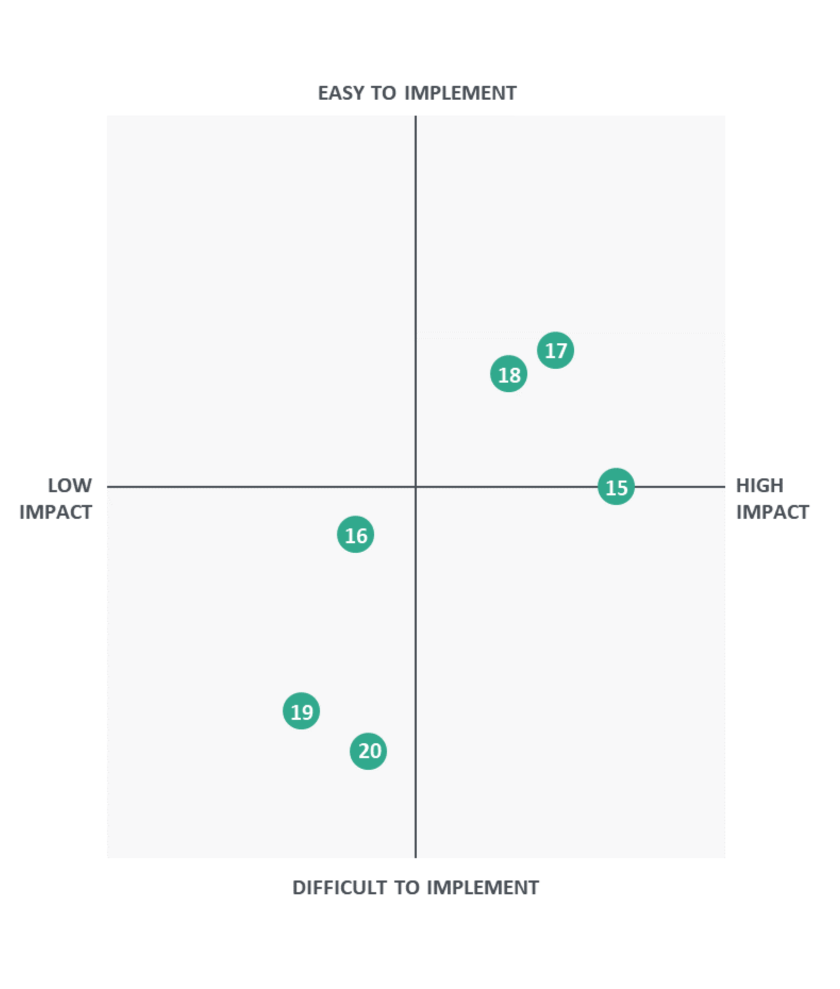
- Adopting new strategies may require process changes and additional investment.
- Overall lack of standardization in utility program design and associated regulation may mean there are regulatory and technical hurdles to adopting best practices.
- Many jurisdictions lack incentives for utilities to continuously improve program design and leverage best practices.

4. 30 Strategies of Large VPP Programs

INCENTIVE DESIGN

Incentive Design Strategies

15	Maximize the financial incentive	**The size of the financial incentive is a key driver of participation.** It should be large enough to be attractive, while still recognizing applicable constraints related to cost-effectiveness.
16	Ensure customer pays a portion of device cost	**Many programs offer an upfront incentive that pays only a portion of the cost of the device so customers are invested in their purchase.** This is particularly effective in programs focused on low-cost devices such as smart thermostats.
17	Offer ongoing participation payments	**Successful programs offer ongoing participation payments to incentivize retention and performance.** The cadence of payments could be aligned with program characteristics (e.g., seasonal for smart thermostats) and could be contingent on performance or control requirements.
18	Bundle device financing options with programs	**Some utilities with innovative emerging programs offer or advertise financing options with some programs.** This can be especially important for programs using expensive devices such as batteries or EV chargers and can help LMI customers adopt these devices.
19	Align price signals	**Successful programs have found solutions to avoid sending the customer conflicting price signals through different programs and pricing structures.** A common issue with VPP/DR programs is that events sometimes shift usage from the retail TOU rate's off-peak period to the on-peak period, unintentionally causing the customer's bill to increase. Solutions include more frequent refinements to TOU window definitions, avoiding calling events outside the peak window, or exempting controlled devices from the TOU rate.
20	Offer active and passive control models	**Some utilities with large portfolios offer two types of programs for some devices (especially EVs):** A time-varying/dynamic pricing offering, where customers can respond by using the device during lower cost hours, and an automated control program, where the utility or an aggregator can control the device, and no customer action is needed.



Note: The feasibility and impact scores for Strategy 18 reflect the views of the authors.

Design an effective financial incentive structure

Successful programs have some of the following incentive design features:

- An upfront incentive that is large enough to be attractive but still accounts for applicable constraints related to cost-effectiveness.
- An upfront incentive that covers only a portion of the full cost of the device, so customers are invested in their purchase
- An incentive for ongoing participation so customers remain enrolled

Strategies #15-17

Potential Impact

- Interviewees generally agreed that providing a significant financial incentive is one of the greatest factors in increasing enrollment.
- At the same time, higher incentives are understood to have decreasing incremental impact, whereby a higher incentive payment doesn't necessarily achieve proportionally higher enrollment. The precise "shape" of this relationship is not fully researched or understood.
- Setting the up-front incentive such that the customer still pays for a portion of the device cost increases the likelihood that customers will install and utilize the device. Programs that provide devices for free have seen that a high number of devices never get installed.
- Ongoing incentives aligned with program performance goals (e.g., a seasonal incentive for seasonal DR events) are key to retaining customers and ensuring effective participation in the program.

Potential Implementation Hurdles

- Programs must provide enough value to justify significant upfront and ongoing incentives. This requires market structures that allow VPPs to pursue and capture value from all the grid services they are capable of providing.
- Finding the most cost-effective balance of budgeting for upfront incentives vs. other program costs can require experimentation.
- Utilities in many jurisdictions are not incentivized to increase spending on VPP programs to maximize participation.

Bundle device financing options with programs

Some utilities with innovative emerging programs offer or advertise financing options with some programs.

This can be especially important for programs using expensive devices such batteries or EV chargers and can help LMI customers adopt these devices.

Strategy #18

Potential Impact

- Reduced barrier to entry for customers with limited ability to finance high upfront costs.
- Potentially lower financing costs for customers.
- Can lock the customer into the program for the duration of the loan.

Potential Implementation Hurdles

- Utilities may need to find a bank or other financial institution to partner with.
- Potential need for regulatory approval for the utility to finance these costs.
- Increased risk to ratepayers of potential bad debt.

Recommendation in Action:

- National Grid advertises no-cost battery financing with Connected Solutions program
- Xcel Energy MN offers EV chargers for rent

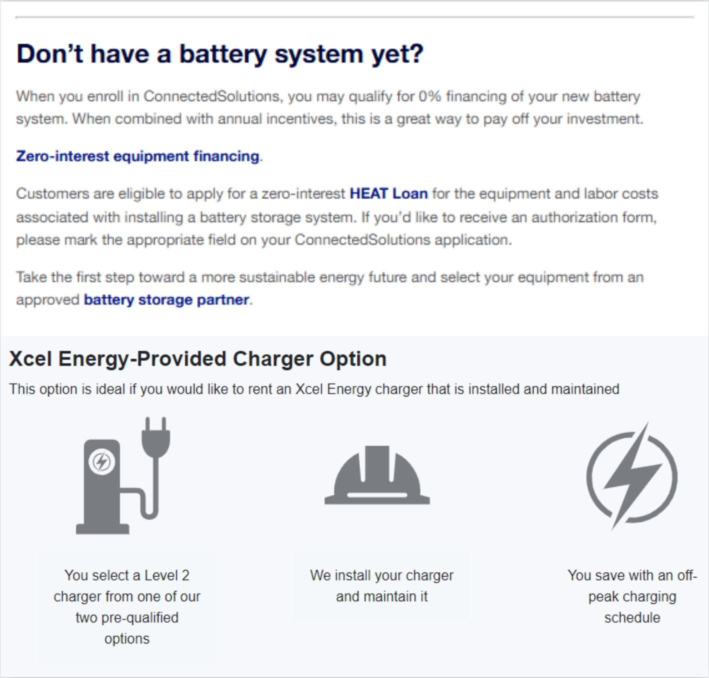


Figure Source: Xcel Energy website

Align price signals

Successful programs have found solutions to avoid sending the customer conflicting price signals through different programs and pricing structures.

A common issue with VPP/DR programs is that events sometimes shift usage from the retail TOU rate's off-peak period to the on-peak period, unintentionally causing the customer's bill to increase. Solutions include more frequent refinements to TOU window definitions, avoiding calling events outside the peak window, or exempting controlled devices from the TOU rate.

Strategy #19

Potential Impact

- While multiple interviewees identified that price signals are sometimes misaligned, they did not identify it as a significant barrier to scaling programs.
- The impact of aligning price signals is likely to be more indirect – unlocking more value by reducing constraints on program operators can improve cost-effectiveness.
- Avoids surprise events that increase customer bills in the on-peak period.

Potential Implementation Hurdles

- Most jurisdictions do not revise TOU rate windows often, leading to misalignment with wholesale market prices.
- Revising TOU rate designs has a high administrative burden and can be hard for customers to follow.
- Exempting a certain device from paying a higher rate during events may not be technically feasible without updates to billing and measurement systems.
- Some ISOs may not yet provide the proper price signal or program for direct VPP participation in the market

Offer active and passive control models

Strategy #20

Some utilities with large portfolios offer two types of programs for some devices (especially EVs):

1. **A time-varying/dynamic pricing offering**, where customers can respond by using the device during lower cost hours
2. **An automated control program**, where the utility or an aggregator can control the device, and no customer action is needed

Potential Impact

- Offers options suited to both customers who prefer a hands-off approach (automated control) or more involved participation (price response).
- Automated control is likely to become more important as EV penetration grows and causes local distribution system constraints.
- Allows enrollment of devices that may only be compatible with one type of control.

Potential Implementation Hurdles

- Increases administrative burden – more programs to design, manage, and regulate.
- Providing customers more options should be accompanied by concise information about the pros and cons and how to choose the right option.
- Additional operation capabilities (e.g., DERMS) and regulatory mechanisms (e.g., NWA frameworks) may be needed to unlock the full value of active control of devices.

Recommendation in Action:

Xcel Energy MN offers four EV charging programs

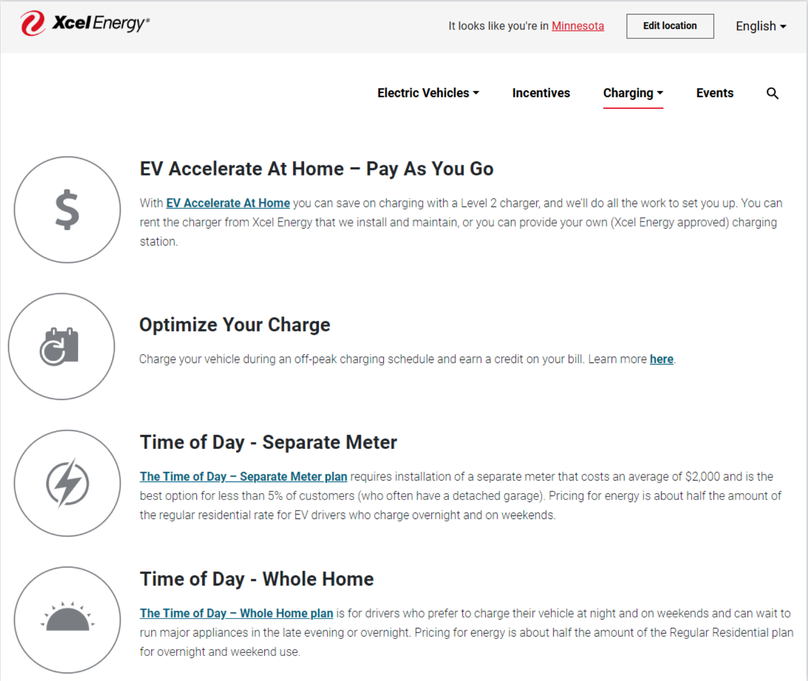


Figure Source: Xcel Energy website

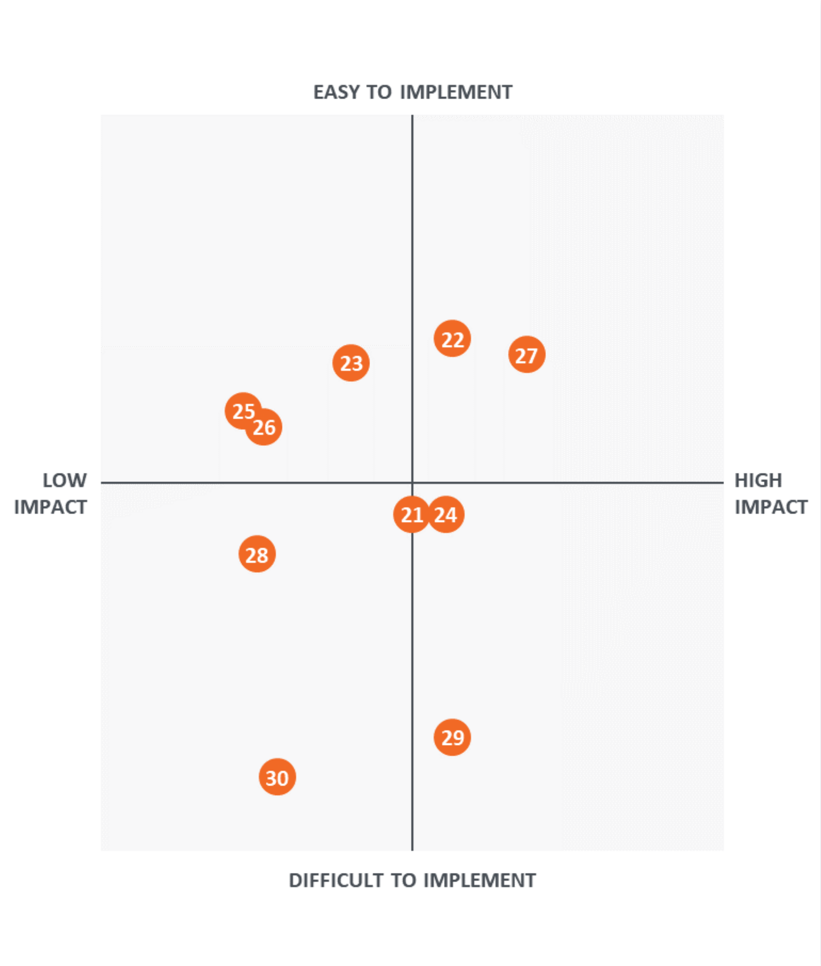
4. 30 Strategies of Large VPP Programs

ENGAGEMENT AND RETENTION

Engagement and Retention Strategies

21	Improve program design over time	**Successful programs continuously learn from implementation experience and refine the design over time.** Beta testing potential new features and building flexibility into programs allows for learning and optimization of program performance.
22	Regularly remind customers of their rewards	**Successful programs send reminders about earned rewards and financial incentives through noticeable channels.** It is important for customers to realize that they are benefitting from participation for continued engagement. Examples of potential noticeable payment methods include Venmo and gift cards rather than utility bill offsets.
23	Compensate through channels customer will notice	
24	Communicate societal impact of participation	**Many successful programs regularly inform customers of the energy and emission reductions resulting from their participation.** This type of communication underscores the benefits of their actions to the community and could increase customer satisfaction.
25	Call regular testing events	**Some large programs call regular DR test events to keep customers accustomed to program participation.** This frequency could reinforce the feeling that they are contributing and "earning" their incentive, while also ensuring that they are not surprised when real DR events are called.
26	Offer easy unenrollment	**Many programs provide straightforward ways to unenroll from a program.** Frictionless unenrollment can reduce the perceived barriers to enrollment and can help non-performing participants easily exit the program.
27	Offer flexibility to opt out of events	**Many programs allow customers to opt out of DR events.** Opt-outs may be limited in some cases or carry a penalty but should be an option so customers can use their devices when needed.
28	Limit event notifications in automated programs	**Large smart thermostat programs have implemented some of the following features:**
29	Allow customers to set control range	
30	Continue offering physical switch-based programs	

- Sending customers one communication at the end of a season, rather than notifications ahead of every event
- Allowing customers to set their preferred range of temperatures not to be exceeded during events
- Continuing to offer traditional switch-based A/C load control programs in parallel to a smart thermostat program



Improve program design over time

Strategy #21

Successful VPP solutions providers continuously learn from their experience administering a program and refine the design over time.

Beta testing potential new features and building flexibility into programs allows for learning and optimization of program performance. Examples include testing different frequencies or channels of communication, different frequencies of DR events, or introducing additional forms of automation.

Potential Impact

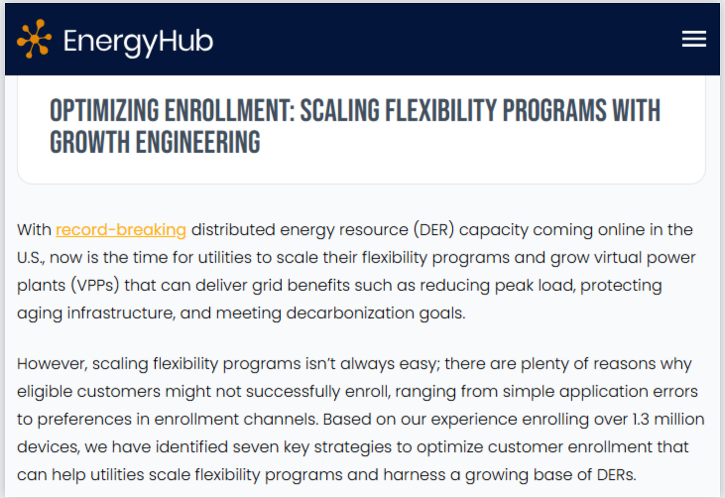
- Programs can be deployed more quickly if they can continue to be refined over time. Less pressure to "get it right" with the initial design.
- The ability to "fail fast" on a small scale allows programs to identify scalable strategies and adaptation based on changing conditions.
- Customer-centric design ensures the final implementation is more aligned with customer needs and expectations.
- Fostering a culture of innovation and experimentation encourages the exploration of new ideas.

Potential Implementation Hurdles

- Too many frequent changes to program design and rules can cause customer fatigue. Finding the right balance between continuous improvement and customer experience can be a challenge.
- Regulators may be concerned with potential impact of beta testing on customers especially if they involve changes to billing, service quality, or participation requirements
- Obtaining informed consent and other standards from participants for data collection and usage can add complexity to the process.

Recommendation in Action:

By iterating and testing of reordering the stages of the program application process, EnergyHub helped utilities increase average conversion rate by 47%. Arizona Public Service saw a 109% increase.


EnergyHub

OPTIMIZING ENROLLMENT: SCALING FLEXIBILITY PROGRAMS WITH GROWTH ENGINEERING

With record-breaking distributed energy resource (DER) capacity coming online in the U.S., now is the time for utilities to scale their flexibility programs and grow virtual power plants (VPPs) that can deliver grid benefits such as reducing peak load, protecting aging infrastructure, and meeting decarbonization goals.

However, scaling flexibility programs isn't always easy; there are plenty of reasons why eligible customers might not successfully enroll, ranging from simple application errors to preferences in enrollment channels. Based on our experience enrolling over 1.3 million devices, we have identified seven key strategies to optimize customer enrollment that can help utilities scale flexibility programs and harness a growing base of DERs.

Figure Source: EnergyHub website

Ensure that customers are aware of earned rewards

Strategies #22-23

Successful programs send reminders about earned rewards and financial incentives through noticeable channels.

It is important for customers to realize that they are benefitting from participation for continued engagement. Potential noticeable payment methods include Venmo and gift cards rather than utility bill offsets.

Potential Impact

- Regular reminders about rewards can serve as a powerful motivator for customer participation and reinforces positive behaviors.
- Ensuring that the customers understand the value they get from the program directly impacts customer retention.
- The same payment may have a larger impact when sent as a reward rather than as a bill discount.

Potential Implementation Hurdles

- Customers may face messaging fatigue and decide to opt-out because they were messaged too frequently.
- Regulators may have concerns about use of alternative payment methods.
- Integration with alternative payment methods may require a significant IT effort.

Recommendation in Action:

RenewHome offers gift cards and cash rewards rather than bill credits

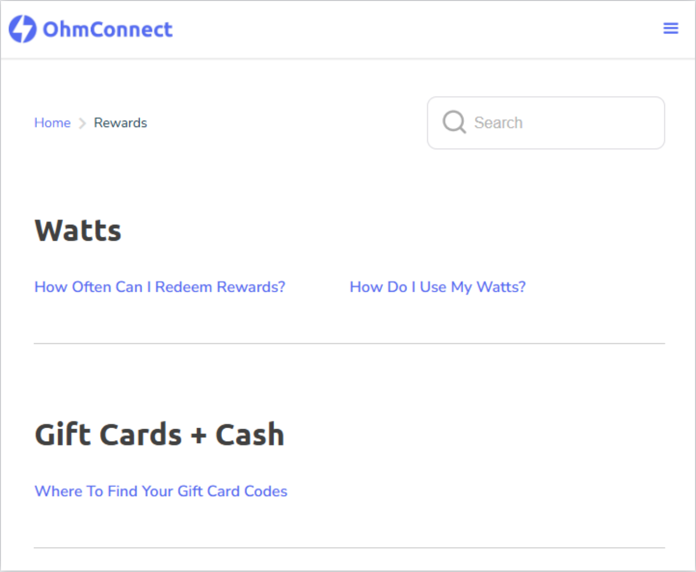


Figure Source: RenewHome website

Communicate societal impact of participation

Strategy #24

Many successful programs regularly inform customers of the energy and emission reductions resulting from their participation.

This type of communication underscores the benefits of their actions to the community and could increase customer satisfaction.

Potential Impact

- Increased customer engagement and lower event opt-out rates.
- Increased customer satisfaction and retention.
- Customers who understand the impact of their participation may be more motivated by non-monetary incentives (e.g., earning a badge in an app).
- Showcasing environmental benefits can enhance the company's brand image and reputation.

Potential Implementation Hurdles

- Developing energy and emission reduction metrics for each customer may require additional effort.
- Complex energy and emissions data can be difficult for all customers to understand.
- Increases the amount of communication the customer receives, potentially contributing to information overload.

Recommendation in Action:

ev.energy smart charger platform provides carbon emissions of every charge in their usage report

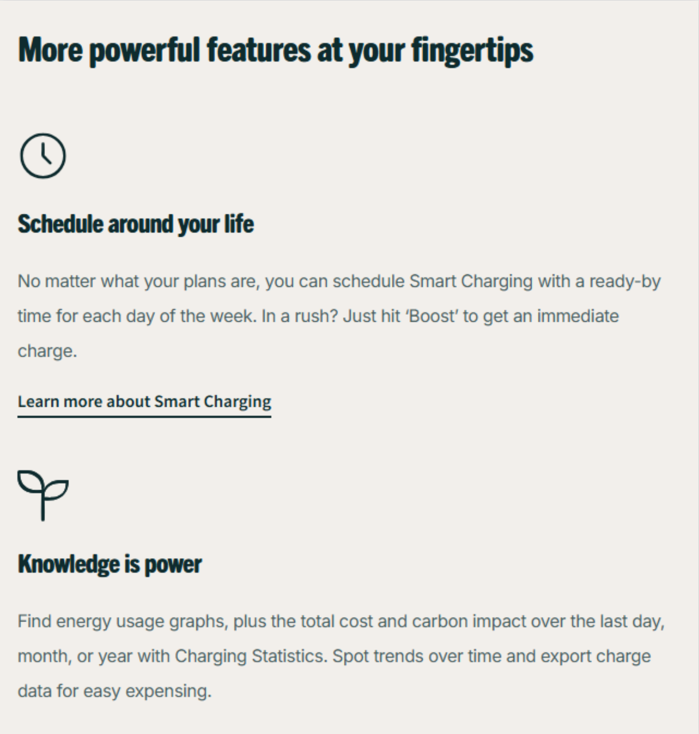


Figure Source: ev.energy website

Call regular testing events

Strategy #25

Some large programs call regular DR test events to keep customers accustomed to program participation.

This frequency could reinforce the feeling that they are contributing and "earning" their incentive, while also ensuring that they are not surprised when real DR events are called.

Potential Impact

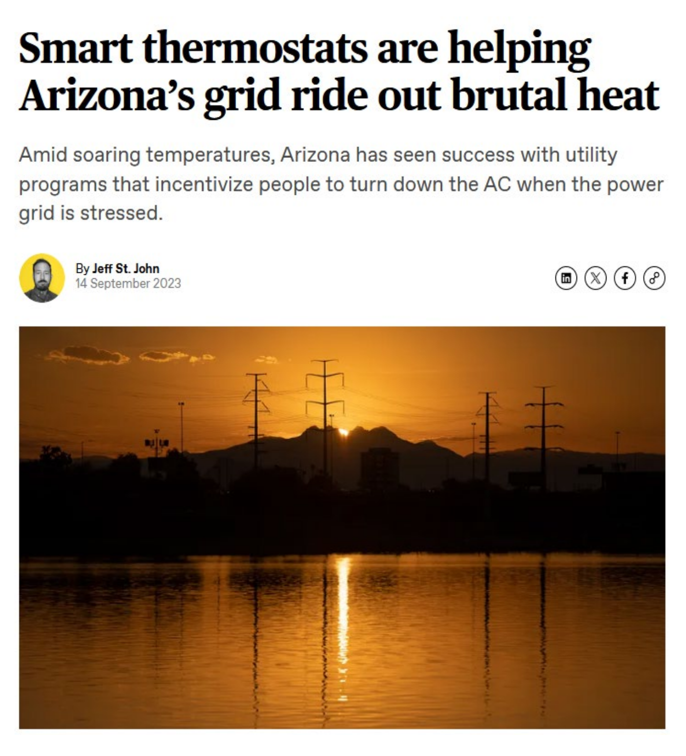
- By helping customers become more familiar with the process, programs can reduce uncertainty and increase comfort levels with participation. More frequent participation can ensure that customers respond predictably to DR signals, fostering a habit of engagement, and improve forecasting.
- Regular events can build trust and transparency, since customers will see the program's ongoing activity and impact.
- Provides more opportunities for customers to give feedback, enabling continuous program improvement.

Potential Implementation Hurdles

- Regular DR events could increase customer fatigue and lead to attrition, or a diminished response if customers think they are not adequately compensated for their participation efforts.
- Developing effective strategies to keep customers engaged and motivated in the long term could be challenging.
- Running regular test events can incur significant operational costs, for communication, data management, analysis, and customer incentives.

Recommendation in Action:

Arizona Public Service's smart thermostat program has called repeat DR events during heat waves and seen reliable participation rates, attributable in part to regular testing



Smart thermostats are helping Arizona's grid ride out brutal heat

Amid soaring temperatures, Arizona has seen success with utility programs that incentivize people to turn down the AC when the power grid is stressed.

By Jeff St. John
14 September 2023

Figure Source: Canary Media website

Provide options to opt out of events or unenroll

Strategies #26-27

Many programs allow customers to opt out of DR events and provide straightforward ways to unenroll from a program.

Opt-outs may be limited in some cases or carry a penalty but should be an option so customers can use their devices when needed. Frictionless unenrollment can reduce the perceived barriers to enrollment and can help non-performing participants easily exit the program.

Potential Impact

- Clear opt-out options demonstrate transparency and respect for customer autonomy, building trust in the program and utility.
- Customers will feel more comfortable enrolling in the program if they feel in control of their participation. The presence of an easy opt-out option can reduce perceived risks and barriers to entry and attract a broader range of participants.
- Understanding why customers opt-out can inform targeted improvements and provide insights on customer behavior and preferences.
- Offering easy unenrollment and removing participants who frequently opt-out can make the program more reliable.

Potential Implementation Hurdles

- Opt-out options could reduce predictability and increase volatility in program performance.
- High opt-out rates could conflict with implementation of other strategies. E.g., lower program benefits caused by high opt out rates may necessitate reduced incentives.
- Ensuring opt-out options are clearly and effectively communicated to all customers across different channels requires well-designed communication strategies and materials.

Recommendation in Action:

Rocky Mountain Power's DR program allows participants to unenroll at any time at no cost

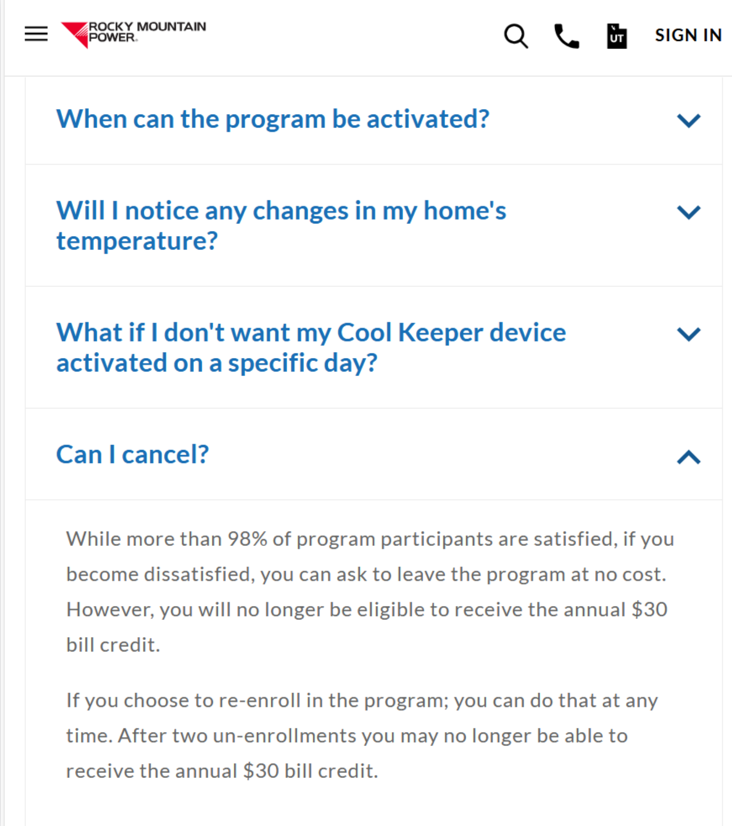


Figure Source: Rocky Mountain Power website

Adopt strategies specific to smart thermostat programs

Strategies #28-30

Large smart thermostat programs have implemented some of the following features:

- Sending customers one communication at the end of a season, rather than notifications ahead of every event
- Allowing customers to set their preferred range of temperatures not to be exceeded during events
- Offering alternative technology choices where available, such as a traditional switch-based A/C load control option in addition to smart thermostats

Potential Impact

- Finding the right cadence of notifications can reduce unnecessary opt-outs and reduce the perception of inconvenience.
- Allowing control of the temperature range during events increases comfort and trust.
- Switch-based DR offers the advantages of allowing more convenient installation and keeping a premise in the program when a customer moves, reducing unenrollment rates relative to smart thermostat programs.

Potential Implementation Hurdles

- Programs may have technical challenges when allowing for customers to set a range of temperatures.
- Offering two programs in parallel increases program complexity and requires customers to figure out the right option.
- Customers may want to be notified before every event.

Recommendation in Action:

Xcel's DR programs offer traditional load control programs in parallel to smart thermostat load control

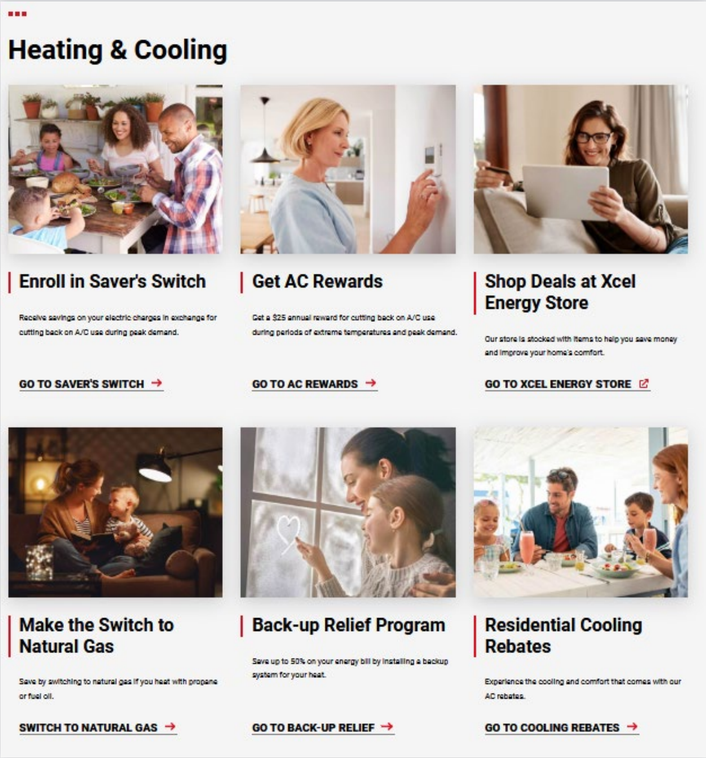


Figure Source: Xcel's Energy website

5. Additional Considerations

Beyond the 30 strategies

This section discusses two additional considerations that could be complementary to the execution of the 30 strategies.

Other barriers and solutions to deploying VPPs: While this report focuses on scaling customer enrollment, there are several other barriers that can be mitigated – in parallel to execution of the 30 strategies – to facilitate broader VPP deployment.

Low-income customer participation: Low-to-moderate income (LMI) customers may have unique barriers and preferences to participate in VPP programs. We describe ten actions VPP solutions providers can take to address LMI customer needs.

Additional barriers and solutions for broader VPP deployment

	Barriers	Solutions
Technical	Communication protocols are not standardized across utilities and lack interoperability between different systems.	State or federal guidance regarding minimum capabilities can help align stakeholders around a common set of protocols. State regulators developing roadmaps and timelines for utilities to achieve critical technical capabilities can spur investment needed to develop these capabilities and create more certainty of cost recovery for utilities.
	Interconnection processes are often slow and cumbersome for customers and aggregators to navigate. Newer technologies are slow to be integrated into utility processes.	
	Data access is often through many different and disjointed channels and may not be possible at all in some jurisdictions. This can be a significant roadblock for customer acquisition and identification of new VPP potential.	
Operational and Planning	Integration of VPPs into planning models and processes is nascent. Planners lack the capabilities to predict customer adoption, accurately characterize VPP costs and grid services, and have certainty on VPP performance during normal and extreme system operations.	Planners can adopt more advanced tools, such as locational DER adoption forecasting, to analyze how VPPs can serve grid needs. Evaluation of VPPs as a solution could become a standard part of the planning process. Piloting can prove emerging operational benefits of VPPs.
	VPPs are often used as an emergency measure and not integrated into normal operating procedures, often due to lack of training or technical capabilities available to grid operators.	Develop procedures that outline when VPPs should be optimally used to provide various grid services. Provide operators the tools needed to automate this process.
	VPPs are not utilized to their full potential to provide distribution grid services due to lack of visibility, control, and telemetry.	Develop a framework for DER orchestration and identify the DERMS capabilities needed to enable coordinated operation and grid services.
Markets and Monetization	VPP programs are often disjointed or confusing for customers and aggregators to navigate.	Programs can be streamlined to enable easier/clearer ways to value-stack across multiple programs (i.e, wholesale and retail), offering additional revenue for VPPs.
	Many regions do not offer any programs or tariffs that VPPs can use to provide distribution grid services.	Time-varying retail price signals or call-based programs can offer opportunities for VPP revenue in the near-term, while utilities expand more sophisticated capabilities for grid orchestration.
	Integration of VPPs into wholesale markets is progressing slowly and faces barriers around the telemetry and control capabilities needed to orchestrate millions of DERs.	Continue to expand and refine existing programs to offer revenue opportunities for VPPs in the interim while long-term solutions are developed.

Sources: A National Roadmap for Grid-Interactive Efficient Buildings," DOE, 2021; VPP Policy Principles, RMI, February 2024; Pathways to Commercial Liftoff: Virtual Power Plants, DOE September 2023.

Considerations for expanding low-income customer participation

To address information asymmetry

1. **Provide information that is culturally and linguistically appropriate** and hold transparent and inclusive educational events to combat low trust in historically underserved communities. Partner with community-based organizations who often have already addressed language barriers and other unique educational outreach considerations.

2. **Partner with public agencies** that promote technology adoption in low-income communities (e.g., California air quality districts created programs to subsidize used EVs if you trade in used gasoline vehicles). [Further Reading: Electric vehicle program designs and strategies to enhance equitable deployment]

To improve program targeting

1. **Target program enrollment** by using census data with metered consumption data to predict underserved neighborhoods that have high energy use.

2. **Critically examine metrics** used to identify and separate low-income communities from others in jurisdictional context (e.g., classifications based on federal poverty guidelines do not work well in California given the much higher cost of housing).

3. **Collaborate with existing programs for fast-tracking income-related verification processes** (e.g., food assistance programs, utility rate discount programs, LIHEAP, WAP, other public agency that can report this data to a utility).

To address financial needs

1. **Avoid punitive incentive structures** to increase community trust and improve customer satisfaction (e.g., peak time rebates may be more effective for driving behavioral change than time-varying rates).

2. **Carve out a significant portion of outreach budgets** for low-income communities (e.g., follow federal Justice40 goal to allocate 40% of program benefits to underserved communities).

3. **Bundle easy access to financing** within programs to increase access for capital-constrained communities.

To provide benefits through program operation

1. **Include device automation and auto-enrollment** with flexibility related programs to help address time-poverty in low-income groups. Automating operations can help certain customer segments access benefits they may not be able to access if manual actions are required.

2. **Consider pollution reduction in disadvantaged communities** as an additional criteria to be optimized through VPP dispatch. Precedence for this exists: the City of Redondo Beach, CA is working with RenewHome to develop a community VPP to eliminate reliance on the local gas peaker plant (~20,000 people live within 1 mile of the plant).

6. Conclusion

From strategy to action

A strategy is only as effective as its execution. The following are three recommendations for regulators, utilities and aggregators to implement the findings in this report when scaling VPP offerings.

Regulators

1. Use the strategies identified in this report as a checklist for ensuring that existing or proposed programs have comprehensively considered established industry practices in their design.
2. When reviewing proposals for VPP pilots, consider requiring that the proposals include a plan to scale following successful implementation of the pilot.
3. Review and address areas where existing regulations may limit successful implementation of certain strategies (e.g., if established cost-effectiveness methodologies do not consider the full value of VPPs, or if there are barriers to “value stacking”).

Utilities

1. Evaluate existing programs against the strategies proposed in this report. While all strategies may not be applicable to a given utility jurisdiction, identify gaps where relevant.
2. Implementing the strategies in this report may require additional funding. Clearly define the potential utility system and ratepayer benefits of the strategies when requesting VPP budget increases.
3. Streamline the enrollment process. This emerged as a key success theme in several interviews but is one of the biggest barriers to program scale today. Utilities can play a central role in addressing this barrier for all customer classes.

Aggregators

1. Aggregators have critical on-the-ground insight regarding the barriers preventing the strategies in this report from being implemented. Identify and advocate for solutions to those barriers in a coordinated fashion.
2. Much of the innovation in consumer engagement has originated with aggregators. Empirical support demonstrating the efficacy of these strategies will help to convince regulators and utilities to enable them.
3. Innovation comes with risk; aggregators will need to deliver on commitments to scale for the themes identified in this report to gain credibility.

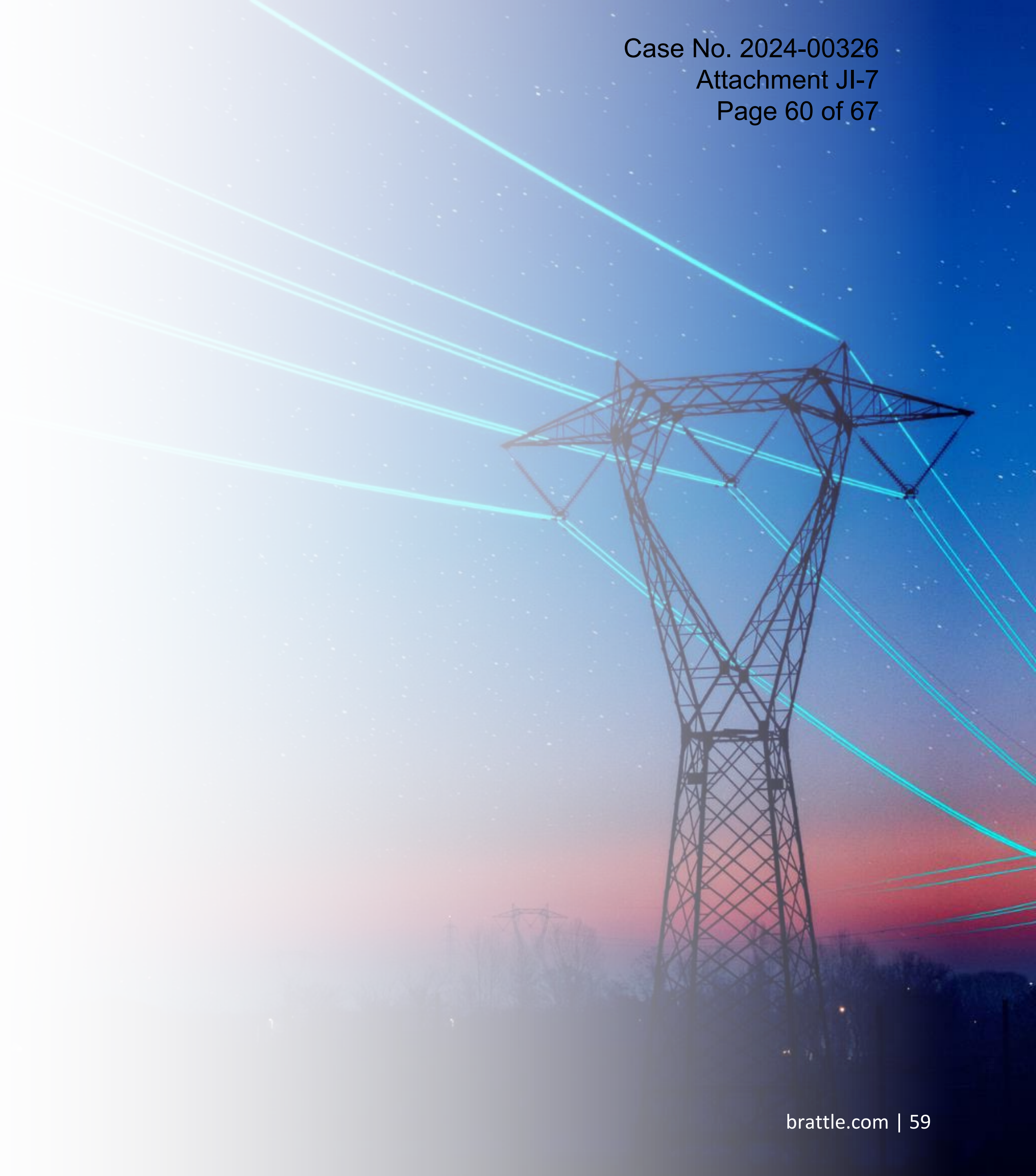
Further research

There are many opportunities to build upon the research framework established for this report, with a goal of accelerating the growth of VPP deployment in the U.S.

Regularly review and identify best practices for VPP enrollment: The VPP market is evolving rapidly. Methods for scaling VPPs will continue to be developed and refined as consumer adoption of DERs grows and new programs are introduced. We recommend updating the findings of this study regularly in order to keep up with rapid market evolution and disseminate successful strategies.

Extend the scope: This study focused on method for increasing consumer participation in VPP programs. However, consumer engagement is not the only factor currently limiting VPP scale. Regulatory, technical, and economic barriers remain. The approach used in this study could be extended to identify successful practices for overcoming barriers such as these.

Consider international experience: Organizations in international jurisdictions are developing innovative approaches to engaging consumers and scaling VPPs. For example, Octopus Energy (now the largest retailer in the UK) offers several products to encourage demand flexibility. European companies are gaining significant experience with managed charging programs as adoption of EVs accelerates.



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Further reading on VPPs

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Appendix

Sources for U.S. Generation Capacity Outlook

		Demand Growth	Supply Growth	Cost
2016 to 2023	VALUE	**24 GW**	**83 GW**	**$90 billion**
	SOURCE NOTES	Estimated from historical data: *EIA, "Peak hourly U.S. electricity demand in July was the second highest since 2016," October 2023.*	Estimated from: *Ryan Hledik, Kate Peters, "Real Reliability" prepared for Google, May 2023 (see pp. 7).* Note: Estimate only includes storage, CCs, and CTs. Values were updated for this presentation with data as of Oct. 2024.	Reported in 2022 dollars. Calculated based on assumed asset installation costs from: NREL Annual Technology Baseline.
2023 to 2030	VALUE	**100+ GW**	**240 GW**	**$250 to $350 billion**
	SOURCE NOTES	Assumes at least 50 GW of data center demand from: *McKinsey, "How data centers and the energy sector can sate AI's hunger for power," September 2024.* Other load growth from: *Tsuchida et al., "Electricity Demand Growth and Forecasting in a Time of Change," 2024 (see pp. 7).*	Assumes 140 GW of retirements from: *US DOE, "Pathways to Commercial Liftoff: Virtual Power Plants," September 2023.* Method: Adds 140 GW to 100 GW from demand estimates	Method: Calculated using same asset installation costs from: NREL Annual Technology Baseline, with inflation adjustments to report the costs in nominal dollars.

Clarity in the face of complexity

Brattle

Energy Markets & Policy
BERKELEY LAB

Bridging the gap on data and analysis for distribution system planning

Information that utilities can provide regulators, state energy offices and other stakeholders

Sean Murphy, Lisa Schwartz, Guillermo Pereira, Cody Davis[1]
[1]Electric Power Engineers

January 2025

This work was supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Bridging the Gap on Data and Analysis for Distribution System Planning:

Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders

Prepared for the
Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

Sean Murphy
Lisa Schwartz
Guillermo Pereira
Cody Davis, Electric Power Engineers

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

January 2025

The work described in this study was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this study was conducted at Lawrence Berkeley National Laboratory and supported by the U.S. Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy under Contract No. DE-AC02-05CH11231.

The authors thank the following experts for reviewing all or portions of this report (affiliations do not imply that these organizations support or endorse this work): Paul De Martini, Newport Consulting Group; Julieta Giraldez, Electric Power Engineers; Jeff Loiter, National Association of Regulatory Utility Commissioners; and Kirsten Verclas, National Association of State Energy Officials. We also thank Paul Spitsen, DOE Office of Energy Efficiency and Renewable Energy, for supporting this study.

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Acronyms and Abbreviations

BCA	benefit-cost analysis
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CEMI	Customers Experiencing Multiple Interruptions
COP	coefficient of performance
DER	distributed energy resources
DOE	U.S. Department of Energy
EPRI	Electric Power Research Institute
EJ	Environmental Justice
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
HCA	hosting capacity analysis
IDSP	integrated distribution system planning
IEEE	Institute of Electrical and Electronics Engineers
kvA	kilovolt-ampere
kW	kilowatt
LRC	lowest reasonable cost
MAIFI	Momentary Average Interruption Frequency Index
MODA	multi-objective decision analysis
MW	megawatt
NERC	North American Electric Reliability Corporation
NWA	non-wires alternative
NYISO	New York Independent System Operator
OT/IT	operational technology/information technology
PG&E	Pacific Gas & Electric
PUC	public utilities commission
PV	photovoltaics
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SCE	Southern California Edison

Executive Summary

U.S. investor-owned utilities spent an estimated $59.7B on electric distribution system investments in 2024, accounting for the largest portion of capital expenditures — 32 percent, according to the Edison Electric Institute. Utilities conduct planning annually to ensure their distribution system meets technical standards, policies, and regulations; addresses forecasted grid conditions; satisfies customer needs; and advances utility priorities. The plan identifies grid deficiencies, analyzes potential solutions, and prioritizes capital investments and other distribution expenditures.

While all utilities conduct planning, about 20 U.S. states and jurisdictions require regulated utilities to file some type of distribution system plan with the public utility commission (PUC) for review. Requirements for sharing distribution system data and analyses vary widely, from few specific requirements to a detailed list of information that must be provided.

While utilities conduct extensive analysis to develop distribution system plans, in most jurisdictions regulators and stakeholders do not know what data are available and how the utility uses the data in planning and investing. This report aims to bridge the gap by increasing understanding of the types of data and analyses utilities employ to develop distribution system plans and how the information affects their decision-making.

The report describes information that states and stakeholders can ask for related to 11 data categories:[1]

1. Forecasting loads and distributed energy resources (DERs)
2. Scenario analysis
3. Worst-performing circuits
4. Asset management strategy
5. Hosting capacity analysis
6. Value of DERs
7. Grid needs assessment
8. Cost-effectiveness evaluation for investments
9. Distribution system investment strategy and implementation
10. Geotargeted programs
11. Non-wires alternatives (NWAs) procurements

Following is a summary of the types of data available for each of these categories and impacts on distribution system planning. Sharing such data provides transparency into the utility's planned capital investments and operation and maintenance expenditures over time. Providing a longer-term, holistic picture of interdependent distribution system investments before they show up individually in utility rate cases facilitates regulatory and stakeholder review and understanding as well as improved oversight of distribution system costs on behalf of utility customers. Transparent distribution system

[1] Berkeley Lab's Integrated Distribution System Planning website includes an interactive planning framework with additional information on these and other data categories.

data and analysis also are useful for review of proposed DER programs and retail rates and enable consumers and third-party providers to propose grid solutions and participate in providing grid services.

Berkeley Lab's data collection tool for this report, in Excel, is available at https://emp.lbl.gov/publications/bridging-gap-between-utilities-and-0. Utilities, regulatory commissions, state energy offices, and other stakeholders can adapt the tool to meet their needs.

1. Forecasting Loads and DERs

Load and DER forecasting informs the timing, need, and type of distribution system investments required to meet estimated peak demand at specific grid locations and times. These forecasts are inputs for multiple distribution planning activities, including assessing grid needs and considering non-wires alternatives. The forecasts also can inform other electricity planning processes such as resource and transmission planning.

Data category	Type of data reported	Impact of data on planning
Gross load forecast	Model parameters and sources	Provides transparency and enables regulators and stakeholders to validate utility decisions and propose alternatives and scenarios
Load-modifying technologies and distributed generation	Input assumptions and modeling decisions on technologies that affect load growth	
New construction	Size, timing, and location of new loads	Characterizes future grid conditions, identifies drivers of increased peak demand, and informs grid investment strategies
Forecast outputs	Peak demand	

2. Scenario Analysis

Scenario analysis examines a range of plausible futures based on potential trajectories of drivers, such as economic and technological factors and weather impacts. Scenarios identify challenges and risks that the distribution system may face in the future and help the utility manage uncertainty by analyzing a range of conditions.

Data category	Type of data reported	Impact of data on planning
Scenario structure	Narrative descriptions	Identifies the types of uncertainties addressed by scenarios
Scenario assumptions		Documents the range of uncertainties used and supports assessment of reasonableness of assumptions
Implications for planning activities		Increases awareness of planning risks and informs discussion of risk mitigation and adaptation

3. Worst-Performing Circuits

Utilities analyze the duration, frequency, and number of customer service interruptions to identify circuits (feeders) with the poorest reliability. For these worst-performing circuits, utilities assess potential root causes and develop remediation plans to improve reliability.

Data category	Type of data reported	Impact of data on planning
Identification of worst-performing circuits	Metrics, methods, and criteria for selecting worst-performing circuits	Focuses efforts on circuits with the poorest performance and resulting local grid conditions
Worst-performing circuit characteristics	Circuit technical details, customer counts and classes, reliability performance, event and maintenance history	Provides historical and operational context for understanding circuit reliability
Remediation plans	Criteria for developing a remediation plan and planned remediation actions	Specifies how utilities plan to respond to known drivers of poor reliability performance

4. Asset Management Strategy

Asset management encompasses all of the ways utilities make decisions about building and maintaining distribution infrastructure. Asset management spans the full life-cycle, from initial equipment selection to design and construction practices to inspection and maintenance and, ultimately, replacement. Common decision-making elements in executing an asset management strategy include assessing asset performance, maintaining and improving reliability and resilience, and efficient budgeting and allocation.

<table>
<tr><th>Data category</th><th>Type of data reported</th><th>Impact of data on planning</th></tr>
<tr><td>Standards and guidelines</td><td>Equipment and design standards, engineering guidelines</td><td>Shapes physical grid infrastructure and types of solutions available to address system challenges</td></tr>
<tr><td>Asset and reliability data</td><td>Reliability indices, equipment testing and inspection data, device settings</td><td rowspan="3">Impacts distribution infrastructure and provides opportunities to coordinate asset management with distribution system planning to optimize spending on capacity upgrades</td></tr>
<tr><td>Programmatic asset-related investments</td><td>Utility programs and associated goals and budgets</td></tr>
<tr><td>Discrete asset management investments</td><td>Asset needs identification and prioritization</td></tr>
</table>

5. Hosting Capacity Analysis

Utilities determine the amount of DERs that can interconnect at a specific point on the grid without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems. Hosting capacity analysis models existing grid conditions and simulates power flow at various levels of DER penetration to determine hosting capacity for distributed generation, battery storage, or new loads such as electric vehicle (EV) charging. Hosting capacity maps can serve as a guide for developers to evaluate potential project sites. Utilities can use hosting capacity information in interconnection processes, as well as in distribution system planning to identify the location and causes of distribution system constraints and assess options to mitigate them.

Data category	Type of data reported	Impact of data on planning
Analytical framework	Criteria for updating hosting capacity analysis and key methodological decisions	Provides transparency and enables regulators to validate utility decisions and propose alternatives
Distribution system infrastructure attributes	Locational, technical, and operational information on substations and feeders	Informs siting of DERs and loads absent power flow simulations
Load characteristics	Peak and minimum demand	Informs siting of DERs and loads
DER capacity	Installed and queued DER capacity	
Hosting capacity estimates	Generation, load, and storage hosting capacity	Informs siting, sizing, and operations of DERs and EV charging stations
Mitigation analysis	Options and costs for mitigating constraints	Provides transparency, enables validation of utility analyses, and provides insight into utility investment decisions and potential alternatives

6. Value of DERs

Utilities quantify the benefits of DERs to the distribution system to inform compensation and guide deployment. More accurate valuation of DERs in distribution planning can help guide DER deployment to areas that improve distribution system outcomes or prevent or defer future distribution system investments.

Data category	Type of data reported	Impact of data on planning
Distribution system input data	Distribution growth expectations, capacity needs, and historical costs	Informs DER programs, which can affect future distribution system planning needs
DER input data	DER types and associated performance characteristics	
Distribution DER value drivers	Value drivers considered and corresponding quantification methodologies	

7. Grid Needs Assessment

A grid needs assessment is an output of distribution system analysis that transparently identifies specific grid deficiencies over a set period. Utilities leverage data from other distribution system analyses for the assessment, including load and DER forecasting and scenario analysis. The assessment includes a description of the deficiency, associated engineering characteristics, and timing of the need. The grid needs assessment informs the utility's distribution system investment strategy, including both traditional grid upgrades and pricing, programs, and procurements for NWAs.

Data category	Type of data reported	Impact of data on planning
Scope	Objectives and regulatory compliance	Establishes the breadth and depth of the assessment and how it fits into the utility's distribution system planning strategy
Analytical approach	Methodology, limitations, and tools	Characterizes the approach implemented to identify grid needs
Grid needs identification	Asset characteristics, description of grid need, cost estimates, timing of grid need, and engineering characteristics	Identifies assets impacted by grid deficiencies
Grid needs selection	Grid needs prioritization and solutions	Selects grid needs for near-term investments and describes the approach that will be used to identify solutions

8. Cost-Effectiveness Evaluation for Investments

Cost-effectiveness evaluation assesses the benefits and costs of grid investments and qualitative factors to achieve established planning objectives to determine an optimal course of action. Utility data on cost-effectiveness can support regulators in assessing and determining which investments may be appropriate for approval and deployment.

Data category	Type of data reported	Impact of data on planning
Solution justification data	Description of selected investments and other expenditures, expected outcomes, investment drivers (compliance with standards, regulations, or policies or enabling other new capabilities), and engineering analyses	Identifies alternatives considered, selected solutions, and rationale
Cost-effectiveness analysis screening	Scope of analysis (individual solution or integrated set of technologies), screening method, estimates of benefits and costs, uncertainty analyses, and ex-post results from prior distribution plans	Determines approach (lowest reasonable cost or benefit-cost analysis) the utility uses for initial economic evaluation of proposed expenditures based on investment drivers
Portfolio development	Scoring and ranking methods (e.g., multi-objective decision analysis, value-spend efficiency) and results, planned portfolio of expenditures	Prioritizes screened expenditures based on cost and potential contribution toward achieving planning objectives to create value for utility customers and society

9. Distribution System Investment Strategy and Implementation

The investment strategy is the utility's plan to achieve the objectives established for distribution system planning. The strategy addresses asset management; reliability and resilience investments including physical upgrades, advanced technologies, and microgrids; capacity expansion including physical upgrades and non-wires solutions, such as customer load flexibility and DER services; and advanced grid technology including for monitoring and control capabilities. The strategy also may include network and data management, planning and operational analytics, and DER enabling technologies.

Data category	Type of data reported	Impact of data on planning
Strategy development	Vision, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and strategic roadmap	Characterizes the long-term evolution of the distribution system and enables regulators to assess alignment with state policy goals and objectives, as well as planning requirements
Strategy implementation	Progress to date, future implementation, investments planned, costs and financing, and risks and mitigation	Connects long-term strategic plans with near-term actions, allowing regulators to understand progress and assess the adequacy of proposed investments in relation to the utility's long-term strategy

10. Geotargeted Programs

Geotargeted programs provide incentives for DERs to reduce load growth for specific locations on the distribution system and reduce the need for upgrades. Utilities and third-party administrators can offer an upfront rebate or other incentive for customers to install a specific technology and opportunities to earn revenues by operating technologies to reduce distribution peak demand.[2]

Data category	Type of data reported	Impact of data on planning
Program needs	Program goals, locational characteristics, and operational and technical requirements	Defines suitability and technical characteristics of geotargeted programs to meet grid needs
Program design and deployment	Eligible measures, program duration, customer participation, and marketing, education, and outreach	Identifies program elements and deployment activities
Evaluation of program performance	Technologies and measures deployed, program effectiveness, community engagement, program budget, and cost-effectiveness	Supports decision-making on continuing and refining program design and deployment

[2] Geotargeted pricing for the distribution system is nascent. See Carvallo, J., and L. Schwartz, 2024, The use of price-based demand response as a resource in electricity system planning.

11. Non-Wires Alternatives Procurements

Utilities can use energy storage, demand flexibility, managed EV charging, and other DERs to provide grid services at specific locations on the distribution system to reduce, defer, or avoid the need for upgrades to infrastructure such as circuits or substations. These NWAs — both front-of-meter and behind-the-meter DERs — can lower peak demand, address voltage issues, improve resilience, and reduce power interruptions.

Data category	Type of data reported	Impact of data on planning
Suitability screening	Criteria for determining whether an NWA is suitable, for a known grid need	Identifies whether NWA processes and technologies are practical for addressing a specific grid need
Technical and cost-effectiveness screens	Methods and input assumptions for determining whether NWA can resolve grid need cost-effectively	Helps regulators understand utility decision whether to pursue NWA
NWA opportunities	Project descriptions and grid need characteristics for NWAs that pass screens	Prescribes how the NWA should perform and informs the selection and operation of NWA DERs
Procurement process	Timeline, review process, bidding rules, and contingency plans	Sets expectations for regulators and NWA providers on how utility procures NWA solutions
Performance evaluation	Data requirements, data cleaning assumptions, and performance metrics	Helps regulators validate utility evaluation methods and NWA vendors achieve desired outcomes

1. Introduction

More than 20 states and jurisdictions in the United States require electric utilities to file some type of distribution system plan.[3] Requirements for sharing planning data and analysis vary widely.

Significant utility investments to replace aging infrastructure and modernize distribution grids — for example, to integrate DERs and electric vehicles (EVs), facilitate grid services by customers and DER aggregators, maintain reliability and resilience in the face of increasing threats, and improve grid flexibility — are increasing interest in distribution system planning. But utility regulators and stakeholders often do not know:

- The breadth, depth, and robustness of available data
- How utilities use the data in planning
- How the data and analysis affect utility decisions

Previous reports on grid data-sharing focused on state requirements,[4] frameworks,[5] or specific types of data such as information used to determine hosting capacity for DERs and DER valuation.[6] This report aims to bridge the gap between utilities and utility regulators — and stakeholders such as state energy offices and utility consumer advocates — on a broad range of grid data available from utilities. The guide describes the types of distribution planning data that state agencies and stakeholders can ask for and the potential impact such data have on distribution system plans and utility and regulatory decision-making.

1.1 Methods

Berkeley Lab researchers reviewed utility distribution plans filed with PUCs to identify data and analyses relevant to the categories covered in this report and assess how the utility used the information. Data categories were selected from key topics in Berkeley Lab's Interactive Decision-Making Framework for Integrated Distribution System Planning. Researchers organized the information in a data collection tool using a structure aligned with this framework. The tool is posted here in Excel format to make it easy for utilities, regulators, and stakeholders to adapt it for their own needs.

Berkeley Lab researchers also interviewed representatives of electric utilities, public utility commissions, and state energy offices (Appendix A) about the types of data and analyses shared in distribution planning proceedings, information-sharing approaches and issues, ways stakeholders use

[3] Berkeley Lab, online catalog of State Distribution Planning Requirements.
[4] National Association of Regulatory Utility Commissioners (NARUC), Grid Data Sharing: Brief Summary of Current State Practices, 2022.
[5] NARUC, Grid Data Sharing Framework, 2023; NARUC, Grid Data Sharing Playbook, 2023.
[6] See, for example, Electric Power Research Institute, 2018, Key Decisions for Hosting Capacity Analyses; Interstate Renewable Energy Council (IREC), 2021, Key Decisions for Hosting Capacity Analyses; IREC and National Renewable Energy Laboratory, 2022, Data Validation for Hosting Capacity Analyses; and NYSEG/RG&E, Benefit Cost Analysis (BCA) Handbook, 2023.

the information, and impacts of data sharing on distribution planning and utility and regulatory decision-making.

1.2 Data-Sharing Findings From Interviews

Information-sharing approaches and issues - Interviewees identified several approaches that utilities use to share information:

- Annual utility reports
- Data requests in formal proceedings or through informal methods
- Discussions outside of proceedings, such as stakeholder working groups
- Utility-hosted websites (e.g., hosting capacity maps) and data portals

Interview participants also identified several data-sharing issues, summarized below, including managing large volumes of data, lack of standardized data, inconvenient data formats, and utility data systems and processes. Participants also described how litigated distribution planning proceedings can hamper data sharing and offered perspectives on how non-litigated processes such as utility- or commission-convened stakeholder working groups can support data sharing.

The large volume of data in distribution planning proceedings can create burdens for utilities as well as regulators, state energy offices, and other stakeholders. For utilities, data reporting can reduce the time for planning analysis and engagement with regulators and stakeholders.

Data overload can make it difficult for regulators and stakeholders to prioritize their review and evaluate information provided. Lack of technical expertise and staff capacity adds to this challenge. One regulator noted that a large volume of data requests can lead to proceedings that focus on compliance with planning requirements instead of focusing on progress toward planning goals. Both utilities and regulators identified strategies to address these challenges. Utilities interviewed said they can educate regulators and stakeholders about the data and automate processes to reduce staff effort in fulfilling reporting requirements. One utility cited progress toward a largely automated process for cleaning hosting capacity data and modeling, reforming a time-intensive manual process. Another utility opined that a use case-based approach could better align data sharing with regulator and stakeholder needs.

Regulators offered the following strategies for mitigating data overload:

- Initially request historical and other data that is readily available
- Establish information filing requirements at the start of distribution planning processes
- Ask utilities to explain cost categories in advance of filing distribution system plans that specify planned investments and other expenditures
- Require data sharing in between plan filings to identify errors before the next filing is due
- Make data requests specific — for example, ask for 15-minute meter data instead of simply “load data” — to avoid misinterpretation by the utility
- Identify what data overlaps distribution planning and other filings, what data is missing, and what data is superfluous

Despite confronting data overload, regulators and state energy offices said they find value in extensive reporting of data for distribution planning. One regulator noted that it can be helpful to have data on hand in case it becomes useful later in the proceeding. A state energy office noted that *integrated* distribution system planning can reduce the effort of staff coordinating across multiple dockets and topics by consolidating data into a single docket.

Regulators and state energy offices observed a lack of standardized data reporting, with the format and definition of each data field varying across utilities and even within utilities, noting that such variation makes it hard to find information and benchmark utility performance. Regulators and stakeholders suggested that standard data dictionaries, cost categories, and reporting templates could address these issues.

Regulators and state energy offices also noted that the format and granularity of utility data can hinder their review of the plan. Utilities often report data in tables embedded in PDFs, which regulators and stakeholders cannot easily analyze. Regulators and state energy offices both expressed a preference for spreadsheets. While more granular data can facilitate more analyses by regulators and stakeholders, a state energy office representative opined that it is reasonable to expect that the granularity of data that the utility shares would correspond with the size of the utility and, in turn, the resource capacity of the utility, as well as filing requirements and level of DERs installed.

Utilities acknowledged that internal systems and processes can affect the availability and quality of distribution planning data. For example, one utility noted that internal data silos can limit the planning team's access to advanced metering infrastructure data. Another utility pointed out that load data for the distribution system may not be available due to a lack of monitoring equipment as well as recording errors. Based on their experience, a state energy office said that utility data systems cannot easily fulfill the agency's data requests in distribution planning proceedings. The agency also noted that updates to utility data systems present opportunities for additional data requests if the utility makes updates with improved information-sharing in mind.

Utilities, regulators, and state energy offices all identified challenges to data sharing in distribution planning proceedings and benefits of coordination outside of litigated processes. They noted that litigated proceedings may offer limited opportunities for clarifying questions about utility data and processes. Utilities offered the following ways that informal stakeholder engagement processes can address these challenges:

- Lower the stakes of discussions, since utility statements on are not on the record
- Allow for more conversation and transparency
- Provide an opportunity to discuss what data are needed and useful
- Involve perspectives of data users who have insight into what data is most useful — for example, DER developer perspectives on hosting capacity data

Similarly, one regulator shared that regular meetings with utilities before filings made data requests easier by providing an opportunity to discuss what commission staff were looking for. This cooperative approach made the utilities more willing to share data.

Using information shared by utilities - Regulators and stakeholders provided examples of how they used distribution planning data provided by utilities to:

- Compare historical, actual, and projected expenditures by a utility and across utilities
- Review and validate utility modeling decisions (e.g., load forecast assumptions)
- Map granular reliability data to socio-economic data to identify equity issues
- Conduct benefit-cost analyses using data on distribution asset capacity and depreciation schedules
- Track circuit reliability — with and without major storm impacts — over time to inform prioritization of investments
- Use cost-effectiveness data to inform commission approval of grid investments

Impacts on planning and utility and regulatory decision-making - Participants identified the following impacts related to data shared by utilities:

- Data for a new reliability metric (CEMI-4) introduced by the utility led to Commission approval of investments
- Regulator's identification of errors in reporting data revealed issues with utility meter installations
- Regulator’s analysis found that reduction in utility staffing was correlated with poor reliability, which ultimately led to the utility improving reliability
- Validation by the state energy office of utility assumptions on battery storage growth rates
- Coordination between the state transportation agency and utilities as a result of utility data accessed by state energy office

1.3 Report Organization

The remainder of this report describes each of the 11 data categories covered and provides examples of utility data-sharing practices, as well as best practices for utility data-sharing, for each category:

- Forecasting loads and DERs
- Scenario analysis
- Worst-performing circuits
- Asset management strategy
- Hosting capacity analysis
- Value of DERs
- Grid needs assessment
- Cost-effectiveness evaluation for investments
- Distribution system investment strategy and implementation
- Geotargeted programs
- NWA procurements

2. Forecasting Loads and Distributed Energy Resources

Load and DER forecasting for distribution system planning informs the timing, need, and type of distribution system investments required to meet estimated peak demand at specific grid locations and times. Load and DER forecasts are inputs for multiple planning activities, including grid needs assessment and non-wires alternatives analysis. These forecasts also can inform other planning processes such as resource and transmission planning.

Distribution system plans can share key input assumptions, modeling decisions, and outputs for:

- Forecasts of gross load, which project historical load trends into the future, but do not account for the impacts of weather-driven DERs (e.g., solar and wind), energy efficiency, demand response
- Load-modifying technologies such as energy efficiency, battery storage, demand response, and building and transportation electrification technologies
- Distributed generation such as solar photovoltaics (PV)
- New construction of housing and commercial and industrial facilities (see Table 2-1)

Table 2-1. Load and DER forecasting data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Gross load forecast	Model parameters and sources	Provides transparency and enables regulators and stakeholders to validate utility decisions and propose alternatives and scenarios
Load-modifying technologies and distributed generation	Input assumptions and modeling decisions on technologies that affect load growth	
New construction	Size, timing, and location of new loads	Characterizes future grid conditions, identifies drivers of increased peak demand, and informs grid investment strategies
Forecast outputs	Peak demand	

3.1 Data Inputs

2.1.1 Gross load forecast

Utilities generate gross load forecasts (1) using time extrapolation with simple linear trending for weather and economic factors or (2) applying a regression model that relates historical load to economic, weather, and demographic parameters to forecasts of those parameters over the study period, projecting these parameters and the resulting changes in gross load over the study period.[7] Distribution system plans can report these parameters and data sources for modeling inputs (see Table 2-2). Utilities also may study planning scenarios by varying parameters such as DER penetration (see

[7] Utilities typically model peak loads only, not 8,760 hours.

Scenario Analysis chapter). Transparency on data inputs and sources increases understanding of forecasting methods by stakeholders and enables them to propose alternative inputs and sources.

Utilities generally do not report historical data used in regression models. Hawaiian Electric is an exception. The utility provided spreadsheets of historical and projected model inputs and sources as part of a working group process.[8] Reporting of historical data facilitates stakeholder analysis and model validation. Utilities also generally do not share data on forecasts of modeling parameters, with the exception of weather data. Utilities often report a design temperature defined by some probability of occurrence. For example, a 90/10 design temperature is the historical temperature at which peak demand is higher than 90% of observed peaks and there is a 10% chance of peak demand being higher. A 90/10 temperature sets an upper bound for expected gross peak demand, whereas a 50/50 temperature represents more normal conditions.[9]

Design temperatures typically reflect long-term historical trends, rather than account for recent changes in weather and future climate change. Some utilities are beginning to account for the impact of climate change in gross load forecasts. For example, Hawaiian Electric incorporated a climate change adder to its projection of cooling degree days.[10] Similarly, National Grid explored the impact of temperature increases from climate change on load in its recent Climate Change Vulnerability Study.[11]

Table 2-2. Regression parameters for gross load forecast

Category	Parameters
Economic	Per capita income, unemployment rate
Weather	Cooling or heating degree days, temperature-humidity index
Demographic	Population
Utility Data	Customer count by class, energy sales by class, electricity price

2.1.2 Load-modifying technologies and distributed generation

Utilities can report technology adoption estimates and other assumptions on how load-modifying technologies and distributed generation will operate. Adoption estimates may be at a utility systemwide level or at a feeder level. National Grid New York, for example, estimated systemwide heat pump adoption using installation targets for its energy efficiency programs and stock projections from a state climate change mitigation pathway.[12] The utility then allocated systemwide heat pump adoption to feeders based on historical adoption records and an adoption propensity model that considers customer demographics. National Grid reported adoption data only for its service area (see Figure 2-1), but its documentation of sources helps regulators and stakeholders understand how the forecast aligns

[8] Hawaiian Electric, *Integrated Grid Plan*, May 2023
[9] ComEd, *Multi-Year Integrated Grid Plan*, January 2023
[10] A *degree day* compares the mean (average of high and low) outdoor temperatures recorded for a location to a standard temperature, usually 65° Fahrenheit in the United States. *Cooling degree days* measure how hot the temperature was on a given day or during a period of days. A day with a mean temperature of 80°F has 15 CDDs. U.S. EIA, "Degree Days." n.d.
[11] National Grid New York, *Climate Change Vulnerability Study*, Case 22-E-0222, September 2023
[12] National Grid New York, *2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment*, March 2024

with state policies and expected technology and market changes. Tabular data can facilitate stakeholders and regulators to perform their own analyses, as in Hawaii.[13]

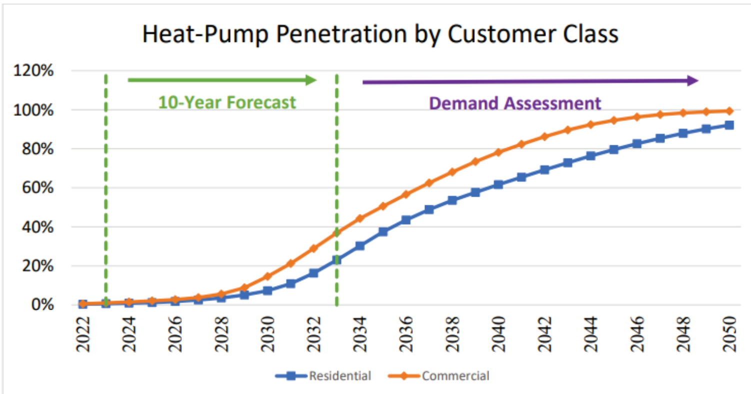


Figure 2-1. National Grid New York service area projections of heat pump adoption

For example, building electrification assumptions can include heat pump efficiency and whether buildings retain the existing heating system as a backup after electrification retrofits.[14] Air-source heat pump efficiency, typically measured by the coefficient of performance (COP), declines with ambient air temperature. Utility assumptions on sensitivity of the COP to temperature, therefore, can affect estimates of winter morning peak demand associated with heat pump adoption. Similarly, retention of existing backup heating systems avoids the adoption of electric resistance backup systems, which can have significant peak demand impacts. For transportation electrification, assumptions for electric vehicle (EV) type[15] (e.g., light duty vehicles, electric buses), vehicle miles traveled, fuel efficiency,[16] and charging strategy[17] impact the timing, location, and magnitude of charging. Utilities also can identify assumptions for battery discharging times and system losses.[18]

Utilities can document sources for all of these modeling decisions. For example, many utilities use EPRI's eRoadMAP™ as a source for EV forecasts. Hawaiian Electric cited the U.S. Energy Information Administration as the source of its fuel economy assumptions, and Green Mountain Power cites historical enrollment in its EV time-of-use rates as the source for its assumed share of managed EV charging.[19] [20] Regulators and stakeholders can use the utility's reported technical assumptions and sources to validate utility decisions and propose alternatives.

Utilities can develop scenarios with different adoption rates and other assumptions for load-modifying technologies for load and DER forecasts (see Scenario Analysis chapter). Xcel Energy in Minnesota, for

[13] Hawaiian Electric, *Integrated Grid Plan*, May 2023
[14] National Grid New York, *2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment*, March 2024
[15] National Grid New York, *2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment*, March 2024
[16] Hawaiian Electric, 2018-0165. Response to Information Requests, July 2020
[17] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021
[18] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, July 2024
[19] Hawaiian Electric, 2018-0165. Response to Information Requests, July 2020
[20] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021

example, estimated low and high adoption levels of rooftop PV relative to changes in installation costs in a medium scenario.[21] Similarly, National Grid New York documented its assumptions for managed charging for light-duty vehicles in its low scenario and unmanaged charging in its base and high scenarios.[22] Utility reporting on these assumptions enables stakeholders and regulators to understand the conditions that forecast scenarios represent.

2.1.3 New construction

New construction forecasts can account for large new loads that utilities expect to serve in the early years of a forecast (≤5 years), including individual large customers or a group of customers in the same location, such as a residential housing development. Utilities can describe how they identify these new loads and report their size, location, and timing. Eversource, for example, provided a narrative on how it accounts for customers that have requested and been approved for at least 500 kilowatt (kW) service.[23]

2.2 Data Outputs

Load and DER forecast outputs that utilities can share in distribution system plans include estimates of peak demand and impacts of load-modifying resources and distributed generation on peak demand. In general, utilities report peak demand at the distribution substation and/or feeder levels that is not coincident with peak demand utility systemwide. Such noncoincidence reflects maximum demand on a particular location of the local grid.[24] For example, noncoincident peak for a circuit (feeder) informs the need for capacity-related upgrades for that circuit.

The granularity of peak demand forecasts reported by utilities varies in terms of time (e.g., single peak hour of the year vs. hourly load shape) and geography (systemwide vs. circuit level). Typically, utilities report single-hour peak demand estimates for each year of a forecast for their service territory as a whole.[25] Such high-level reporting shows projected overall demand growth, but not how growth varies geographically—today and over time. Alternatively, utilities can provide hourly load shapes for peak days[26] or weeks that include peak days. Green Mountain Power, for example, presented load profiles for weeks that include summer and winter peak days to show how heat pump adoption shifts annual peaks from summer afternoons to winter mornings and how rooftop solar adoption decreases annual minimum net demand (Figure 2-2).[27]

Utilities can provide more geographically granular load forecast results, at the circuit or substation level.[28] NV Energy, for example, provided ratings and annual peaks for individual substation

[21] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[22] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[23] Eversource Energy, Forecasting and Electric Demand Assessment Methodology, April 2023
[24] In contrast, coincident peak demand for a circuit reflects demand at that location during the utility system's peak demand.
[25] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[26] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[27] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021
[28] Southern California Edison, 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report, January 2023

transformers in each year of its short-term (five-year) forecast.[29] Circuit- and substation-level peak demand data provide transparency for grid needs assessments, indicating where and when constraints appear.

Forecast outputs for load-modifying technologies include both peak demand impacts and load shapes. As Figure 2-2 shows, Green Mountain Power's peak-week load profile showed the contribution of EV charging (green) and heat pumps (red).[30] Similarly, National Grid New York provided tables detailing increases to peak demand attributable to EV charging and heat pumps, as well as decreases to peak demand resulting from energy efficiency, rooftop PV, energy storage, and demand response for six planning zones.[31] These technology-specific breakdowns of peak demand make clear what technologies drive peak increases and inform peak mitigation strategies.

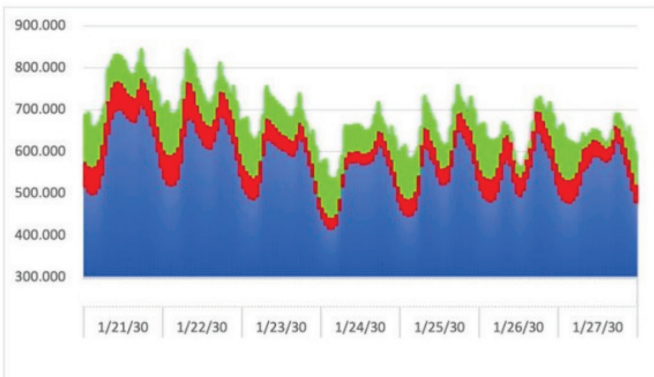


Figure 2-2. Green Mountain Power 2030 winter peak demand week load profile

Note: Blue is baseload net demand, green is EV charging, and red is heat pumps.

2.3 Best Practices

Best practices for sharing data on load and DER forecasting include:

- Identify parameters and design temperatures used in gross load forecasts
- Provide estimates of DER and load-modifying technologies at the feeder-level
- Document assumptions for operation of DERs and load-modifying technologies
- Develop forecasts for different scenarios of DER and load-modifying technology adoption and operation
- Describe criteria for including large new loads in the forecast
- Provide hourly load shapes for peak days that show the impacts of DERs and load-modifying technologies
- Provide estimates of peak demand, and impacts of DERs and load-modifying technologies on peak demand, by circuit

[29] NV Energy, *Narrative Distributed Resources Plan and Technical Appendix*, June 2021
[30] Green Mountain Power, *2021 Integrated Resource Plan*, December 2021
[31] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024

3. Scenario Analysis

Scenario analysis examines a range of plausible futures based on potential trajectories of planning drivers—either indirect (e.g., economic and technological factors) or direct (e.g., load growth and severe weather impacts).[32] Scenarios can identify challenges and risks that the distribution system may face in the future and can manage uncertainty by analyzing a range of conditions. Scenario analysis uses both quantitative and qualitative information to stress test distribution plans by:

- Determining least-regret investments under different potential conditions
- Assessing needed plan flexibility and plan robustness

Scenarios also can guide decision-making to manage different levels of risk and uncertainty. Table 3-1 summarizes a scenario-based decision-making framework for distribution planning developed by the Electric Power Research Institute (EPRI).[33] The framework describes how an exclusive focus on "no regrets" actions required in *most or all* scenarios can increase the likelihood of risks such as overloads. EPRI also explains how utilities can mitigate risks by taking actions required in *any* scenario and introduce flexibility by staging the implementation of planned actions.

Table 3-1. Scenario-based decision-making framework adapted from EPRI[34]

Approach	Description
No regrets	Proceed with actions necessary for all or most scenarios.
Most likely	Apply "likelihood factors" to move forward with initiatives that are more likely to be necessary.
Worst case	Address the full range of risks that develop in any of the scenarios.
Leveraged	Proceed with actions with a higher operational risk (No regrets/Most likely) and scale project to address a worst-case scenario.
Staged	Proceed with worst-case actions but advance the necessary elements in multiple phases.

Utilities can provide narratives in distribution system plans that describe the structure of scenarios used, assumptions that differentiate scenarios, and implications of scenarios on planning activities (see Table 3-2). Reporting on these planning activities can provide additional data that reflect the scenarios.

32 Scenarios are distinct from contingency planning procedures in which utilities assess the ability of circuits or transformers to serve load while adjacent infrastructure is not energized due to maintenance or equipment failures.
33 EPRI, Distribution System Scenario Planning, August 2024
34 EPRI, Distribution System Scenario Planning, August 2024

Table 3-2. Scenario analysis data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Scenario structure	Narrative descriptions	Identifies the types of uncertainties addressed by scenarios
Scenario assumptions		Documents the range of uncertainties used and supports assessment of reasonableness of assumptions
Implications for planning activities		Increases awareness of planning risks and informs discussion of risk mitigation and adaptation

3.1 Data Inputs

3.1.1 Scenario structure

Utilities that use scenario analysis in distribution planning typically use one of the following approaches:[35]

1. *Alternative futures scenarios* are used in the forecasting process to understand a range of plausible futures as an input for planning, such as a base case, high case, and low case. For example, DTE Electric considered electrification, distributed generation, and catastrophic storm scenarios in its 2023 Distribution Grid Plan.[36] The electrification scenario explores EV adoption greater than expected in the reference forecast for the utility's 2022 integrated resource plan.[37] The high distributed generation scenario considers increased adoption of PV and battery storage. In New York, National Grid differentiates PV adoption in its base and high scenarios by the share of the state's 2050 target for state PV deployment achieved.[38] Similarly, Xcel Energy Minnesota examines base case, medium, and high levels of DER adoption in accordance with state requirements to address uncertainty in DER deployment.[39] [40]
2. *Discrete scenarios* are used in distribution planning to assess least-regret investments that address more than one critical issue. Critical issues typically are driven by key factors that are largely independent of each other and have material impacts on grid needs. For example, electrification growth is independent of increasing storm severity with respect to distribution system impacts. The utility selects scenarios from the alternative futures described above. The

[35] Alternatively, utilities can use sensitivities of various forecast variables based on Monte Carlo analysis and provide a probability distribution for each variable. Sensitivity analyses for scenarios explore a change in outcomes due to a change in a single input. They are typically used for load and DER forecasting and for climate/weather projections for resilience assessments.
[36] DTE Electric, *2023 Distribution Grid Plan, Case U-20147*, September 2023
[37] De Martini, "Integrated Distribution System Planning," presentation for National Rural Electric Cooperative Association, September 2024
[38] National Grid New York, 2024 to 2033 Electric Peak (MW) Forecast and 2050 Load Assessment, March 2024
[39] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[40] Minnesota Public Utilities Commission, Docket 18-251, Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy, August 2018

objective of discrete scenarios analysis is to determine the potential impact of each of the factors studied to identify overlapping grid needs for least-regret investments.

Narratives can describe the structure of the scenarios the utility used and identify uncertainties addressed.

3.1.2 Scenario assumptions

Assumptions that define scenarios can address uncertainty related to technology adoption, efficiency, and operations. For example, Xcel Energy in Minnesota considered greater EV adoption in a high scenario using lower battery prices and higher gasoline prices relative to its medium scenario.[41] Hawaiian Electric illustrated how utilities can make assumptions about types of technologies customers will install and how customers will use them. As Table 3-3 shows, Hawaiian Electric explored a high value for peak demand by assuming that customer EV charging is unmanaged in its High Load and Unmanaged Electric Vehicles scenarios.[42] Such documentation identifies the range of uncertainties that the utility factors into planning activities. This information enables regulators and stakeholders to assess whether scenarios align with state policies, expected market and technology changes, and climate change mitigation pathways.

Table 3-3. Hawaiian Electric 2023 Integrated Grid Plan scenario assumptions[43]

Modeling Scenario	Purpose	DER Forecast	EV Forecast	EE Forecast	Non-DER/EV TOU Forecast	EV Load Shape	Fuel Price Forecast	Resource Potential
Base	Reference scenario.	Base	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Land-Constrained	Understand the impact of limited availability of land for future solar, onshore wind and biomass development.	Base	Base	Base	Base	Managed EV charging	Base	**Land-Constrained Resource Potential**
High Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that lead to higher loads.	**Low**	**High**	**Low**	**Low**	**Unmanaged EV charging**	Base	NREL Alt-1
Low Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that leads to lower loads.	**High**	**Low**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Faster Technology Adoption	Understand the impact of faster customer adoption of DER, EV and EE.	**High**	**High**	**High**	**High**	Managed EV charging	Base	NREL Alt-1
Unmanaged Electric Vehicles	Understand the value of managed EV charging relative to unmanaged.	Base	Base	Base	Base	**Unmanaged EV charging**	Base	NREL Alt-1
DER Freeze	Understand the value of the distributed PV and BESS uptake in the Base forecast. Informative for program design and solution sourcing.	**DER Freeze**	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Electric Vehicle Freeze	Understand the value of the electric vehicle's uptake in the Base forecast. Informative for program design and solution sourcing.	Base	**EV Freeze**	Base	Base	Managed EV charging	Base	NREL Alt-1
High Fuel Retirement Optimization	Understand the impact of higher fuel prices on the resource plan while allowing existing firm unit to be retired by the model.	Base	Base	Base	Base	Managed EV charging	**EIA High Fuel Price**	NREL Alt-1
Energy Efficiency Resource	Understand the value of energy efficiency as a resource. Informative for program design and solution sourcing.	Base	Base	**EE Freeze + EE Supply Curves**	Base	Managed EV charging	Base	NREL Alt-1

3.2 Data Outputs

Scenario narratives can identify potential challenges and risks to distribution system planning activities based on analysis performed by utilities or third parties. DTE Electric, for example, describes how EV

[41] Xcel Energy Minnesota, *Integrated Distribution Plan 2024-2033*, November 2023
[42] Hawaiian Electric, *Integrated Grid Plan*, May 2023
[43] Hawaiian Electric, *Integrated Grid Plan*, May 2023

adoption could increase the number of capacity-constrained substations, resulting in higher risks of outages during grid contingencies. Similarly, ComEd discusses the risks of climate change in its 2023 Integrated Grid plan based on a study the utility conducted with Argonne National Laboratory.[44] [45] The study indicates that longer growing seasons could increase the risk of damage to distribution infrastructure from vegetation and that the utility may need to derate transformer capacity due to higher air temperatures (see Figure 3-1). These narratives can make stakeholders and regulators aware of risks to the distribution system and provide a starting point for further analysis and discussion on mitigating and adapting to identified risks.

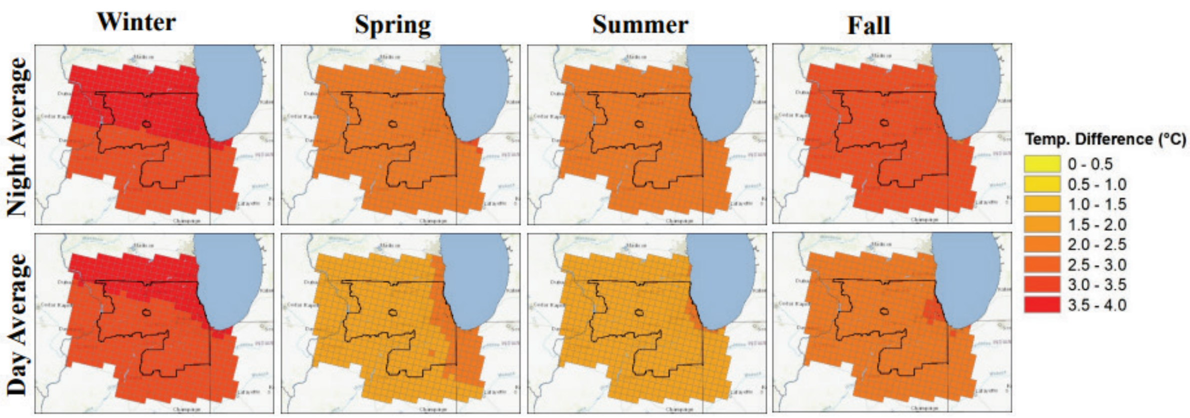


Figure 3-1. Estimates of seasonal daytime and nighttime changes in average minimum temperature: 1995–2004 baseline to mid-21st century[46]

Utilities also can report data on the planning activities to which they apply scenarios. For example, utilities often develop load forecasts across multiple scenarios that differ in trends for customer load, the adoption of EVs, building electrification technologies, distributed generation and storage technologies, and market and fuel prices among other factors. Such scenarios inform detailed system planning analyses that determine potential distribution needs and related scope, scale, and timing considerations.

Salt River Project, for example, estimates the need for major investments in existing and new substations across four scenarios that reflect possible load growth trajectories for the utility (Figure 3-3).[47] The scenarios differ in terms of economic growth, carbon policy, climate change impacts, and technology costs, among other factors. By extending scenarios into grid needs assessment, the utility is able to determine the plausible range of investments it may need to make over the planning period.

[44] ComEd, Multi-Year Integrated Grid Plan, January 2023
[45] Burg, Kartheiser, Mondello, et al., *ComEd Climate Risk and Adaptation Outlook, Phase 1: Temperature, Heat Index, and Average Wind*, November 2022
[46] Burg, Kartheiser, Mondello, et al., *ComEd Climate Risk and Adaptation Outlook, Phase 1: Temperature, Heat Index, and Average Wind*, November 2022
[47] Salt River Project, *2023 Integrated System Plan*, 2023

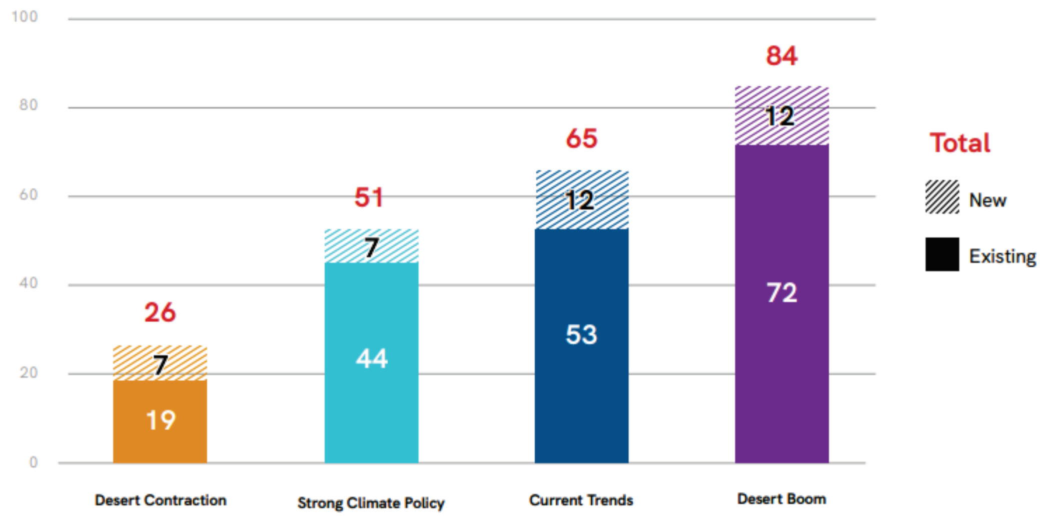


Figure 3-2. Salt River Project substation bay additions through 2045 by planning scenario[48]

3.3 Best Practices

Best practices for sharing data on scenario analysis include:

- Clearly describe the structure of scenarios used and the uncertainties that each scenario addresses
- Document assumptions that differentiate scenarios
- Provide narrative descriptions that identify risks and challenges of planning activities for each scenario
- Report scenario-specific data that utilities apply to scenarios, such as load and DER forecasts

[48] Salt River Project, *2023 Integrated System Plan*, 2023

4. Worst-Performing Circuits

Utility engineers analyze data on the frequency, duration, and number of customer service interruptions to identify circuits (or feeders) with the worst reliability performance. For these "worst-performing circuits," utilities assess potential root causes and develop remediation plans to improve reliability. Many states require that regulated utilities annually submit a list of worst-performing circuits, along with reliability metrics and a remediation plan for each circuit. This process supports prioritizing reliability improvements for customers that have experienced the highest frequency and/or duration of power interruptions.

Data and analyses reported on worst-performing circuits provide transparency into reliability performance for individual circuits and utility processes for selecting circuits for remediation. Utility reporting can describe the metrics and criteria used to classify the worst-performing circuits, provide detailed characteristics of those feeders, and delineate remediation plans (Table 4-1).

Table 4-1. Worst-performing circuit analysis data categories and impacts on planning

Data category	Types of data reported	Impact of data on planning
Identification of worst-performing circuits	Metrics, methods, and criteria for selecting worst-performing circuits	Focuses efforts on circuits with the poorest performance and resulting local grid conditions
Worst-performing circuit characteristics	Circuit technical details, customer counts and classes, reliability performance, event and maintenance history	Provides historical and operational context for understanding circuit reliability
Remediation plans	Criteria for developing a remediation plan and planned remediation actions	Specifies how utilities plan to respond to known drivers of poor reliability performance

4.1 Data Inputs

4.1.1 Identifying worst-performing circuits

Utilities identify worst-performing circuits by ranking them according to reliability performance metrics and applying selection criteria to those metrics. Table 4-2 defines metrics that utilities use to characterize electric power reliability. Utilities can report data on several factors that affect the outcome of worst-performing circuits analysis, including the choice of metric, the types of interruptions eligible for analysis, and the period over which utilities calculate a metric.

Table 4-2. Definitions of common electric power reliability metrics[49]

Metric	Description	Interpretation
SAIFI	System Average Interruption Frequency Index	Total number of sustained interruptions that an average customer experiences over some time period
SAIDI	System Average Interruption Duration Index	Total number of minutes than an average customer is without power over some time period
CAIFI	Customer Average Interruption Frequency Index	Average number of interruptions per customer interrupted over some time period
CAIDI	Customer Average Interruption Duration Index	Time required to restore service for an average customer over some time period
MAIFI	Momentary Average Interruption Frequency Index	Total number of momentary interruptions (< 5 minutes) than an average customer experiences over some time period
CEMI	Customers Experiencing Multiple Interruptions	Individual customers who experience more than some threshold number (e.g., four) interruptions of at least one minute over some time period.

The reliability performance metric that utilities use affects how the frequency, duration, and breadth of interruptions drives which circuits are worst-performing. For example, frequency-based metrics (e.g., SAIFI) prioritize circuits with frequent but short interruptions compared to duration-based metrics (e.g., SAIDI), which prioritize circuits with long-duration interruptions. Interruptions that affect a small number of customers can have a large impact on CAIDI and CAIFI, but not SAIDI and SAIFI, because they quantify impacts on customers interrupted, not all customers served. However, metrics that use averages—whether for frequency, duration, the whole circuit, or customers interrupted—can obscure individual customers that have poor reliability and fail to identify circuits that serve them. CEMI addresses this issue by identifying individual customers with poor reliability, which utilities can then use to identify circuits. Rhode Island Energy,[50] for example, uses CEMI-4 (percent of customers experiencing at least four interruptions of one minute or more in the past year) to prioritize circuits for line reclosers in a program that complements its worst-performing circuit analysis.

Utilities can rank circuit performance with multiple performance metrics. Pacific Gas & Electric,[51] for example, uses both CAIFI and CAIDI to identify worst-performing feeders. Orange and Rockland

[49] Definitions are from Schellenberg, J., and L. Schwartz. *Grid Resilience Plans: State Requirements, Utility Practices, and Utility Plan Template*, 2024, Table 3-6.
[50] Rhode Island Energy, *Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan*, 2023
[51] PG&E, *2022 Annual Electric Reliability Report*, 2023

Utilities[52] uses a weighted score that accounts for SAIFI and the number of interruptions and customers affected, among other variables.

Some types of outages may be excluded from consideration in reliability metrics. That affects what grid conditions the analysis represents. Excluding interruptions that result from major weather events, maintenance,[53] or generation and transmission issues[54] omits one-off or infrequent events (e.g., major storms) that do not contribute to persistent reliability issues, focusing performance on standard distribution system operations. Metrics are calculated annually, giving significant weight to one-off or infrequent events (e.g., major storms) that do not contribute to persistent reliability issues, which can justify their exclusion.

State reporting requirements may determine which interruptions utilities exclude when calculating reliability metrics. Missouri,[55] for example, requires that utilities use an engineering standard (IEEE-1366) to determine major event days that can be excluded from circuit-level SAIFI scores that inform identification of worst-performing circuits. The standard provides a statistical method for identifying major event days based on daily SAIDI measurements.[56] Absent regulatory guidance, utilities develop and report on their own approaches, such as in New York.[57] For example, National Grid excludes interruptions from major storms but includes interruptions from transmission issues.[58]

Utilities also can share criteria they use for selecting worst-performing circuits based on reliability performance. These criteria often include some defined percentage of circuits with the lowest score for one or more metric. Illinois, for example, identifies any circuit as worst-performing if it is in the one percent highest SAIFI, CAIDI, or CAIFI scores among all circuits (higher score means lower performance).[59] Similarly, Florida defines the three percent of circuits with the most interruptions as worst-performing.[60]

4.2 Data Outputs

4.2.1 Worst-performing circuit characteristics

Table 4-3 identifies data that utilities report on characteristics of worst-performing circuits. Utilities and regulators use the information to track circuit performance over time. Technical details provide context for causes of interruptions, potential remediation actions, and level of effort required. Pacific Gas & Electric,[61] for example, provides the total length of circuits as well as the percent of the circuit length

[52] Orange & Rockland Utilities, *Service Reliability Filing for 2022 System Performance*, 2023
[53] PG&E, *2022 Annual Electric Reliability Report*, 2023
[54] Florida Public Service Commission, Rule 25-6.0455, Annual Distribution Service Reliability Report, 2006
[55] Missouri Code of Regulations, Title 20 4240-23.010, 2024
[56] IEEE, IEEE 1366-2003, 2004
[57] New York Public Service Commission, Case 2-E-1240, 2004
[58] National Grid, Annual Electric Reliability Report for 2023, 24-E-0140, 2024a
[59] Illinois Commerce Commission, Illinois Administrative Code, 83.1.c.411, 2022
[60] Florida Public Service Commission, Rule 25-6.0455, Annual Distribution Service Reliability Report, 2006
[61] PG&E, *2022 Annual Electric Reliability Report*, 2023

underground, both of which are relevant to the outages experienced and remediation actions the utility undertakes. Data on the customers served by a circuit, such as the number on medical or life-support systems[62] registered with the utility, indicates the potential health risks of poor reliability.

Table 4-3. Characteristics of worst-performing feeders

Circuit characteristic	Data reported
Identifying information	• Circuit name/ID • Substation name/ID • Location
Technical details	• Voltage • Circuit length
Customers	• Number of customers on circuit by customer class • Number of customers on medical or life-support systems
Event history	• Date of interruptions • Number of customers affected by event • Duration by event • Cause of event
Reliability performance	• SAIDI, SAIFI, CAIDI, CAIFI, MAIFI • Total duration of interruptions • Total number of customers interrupted • Number of interruption events • Number of equipment outage events • Years in which circuit has been on worst-performing list
Maintenance history	• Date of last tree trimming • Date of last inspection • Description of measures already taken to address previously identified reliability issues • Cost and timeline for actions already taken to address previously identified reliability issues

Event history data can include the causes and impacts of individual interruptions to inform mitigation strategies. New York State Electric and Gas Company, for example, reports the number and duration of interruptions and number of customers interrupted by standard causes such as trees, overloads, equipment failure, and lightning (Table 4-4).[63] This detailed breakdown makes it clear to regulators what remediation efforts (e.g., tree trimming or equipment replacements) are most likely to improve reliability.

[62] Ohio Administrative Code, 4901:1-10-01, 2024
[63] New York State Electric and Gas, 2022 Annual Reliability Report, 2023

Table 4-4. Causes of interruptions for a single circuit: New York State Electric and Gas Company[64]

CRARYVILLE 400

	Interruptions		Customers Interrupted		Customer Hours of Interruption	
Tree In Row	7	11.48%	169	2.44%	619.503	4.29%
Tree Out Row	28	45.90%	3378	48.82%	4993.385	34.54%
Overloads	2	3.28%	229	3.31%	646.109	4.47%
Operational Errors	0	0.00%	0	0.00%	0	0.00%
Equipment Failures	7	11.48%	549	7.93%	207.464	1.44%
Accidents/Non-Utility	4	6.56%	1865	26.95%	6294.908	43.55%
Prearranged	1	1.64%	9	0.13%	19.647	0.14%
Customer Equipment	1	1.64%	1	0.01%	1.167	0.01%
Lightning	7	11.48%	531	7.67%	1242.753	8.60%
Unknown	4	6.56%	189	2.73%	430.749	2.98%
Totals	61	100%	6920	100%	14456	100%

Reliability performance data for worst-performing circuits provides standard reliability metrics and aggregate measurements of performance across all events, such as the total number of customers experiencing interruption. These data cover the reporting year and often include historical performance data, as well. Ameren Illinois, for example, provides SAIFI, CAIFI, and CAIDI for each worst-performing feeder for the three preceding years.[65] Appearing on the worst-performing list in previous years indicates continued performance issues, informing the selection of circuits for remediation.

Maintenance history data indicate whether a utility already has taken preventative or mitigation measures to improve circuit reliability. Commonwealth Edison, for example, reports the date of the most recent tree trimming and mainline and tap inspections (Figure 4-1).[66] These data help inform the extent of utility progress in addressing reliability issues for individual circuits and which circuits to prioritize for future maintenance.

4.2.2 Remediation Plans

Utilities develop remediation plans to mitigate worst-performing circuit reliability. Data can include the criteria for selecting the worst-performing circuits for remediation and details on specific remediation actions. Missouri, for example, requires remediation plans for “Multi-Year Worst Performing Circuits”—those that appear on the worst-performing list for any two of the three most recent consecutive calendar years.[67]

[64] New York State Electric and Gas, 2022 Annual Reliability Report, 2023
[65] Ameren Illinois, Response to 83 Illinois Administrative Code 411: 2022 Annual Report, 2023a
[66] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a
[67] Missouri Code of Regulations, Title 20 4240-23.010, 2024

Detailed data on remediation actions includes specific actions that utilities have taken, and plan to take, as well as related timelines and cost estimates. Ameren Missouri, for example, provides a narrative description of its remediation efforts that relates specific actions (e.g., tree trimming) to the cause of interruptions (e.g., trees falling on lines).[68] As Figure 4-1 shows, Commonwealth Edison[69] reports total cost estimates for all planned and completed work. Planned work descriptions can range from high-level descriptions to technical specifications that include the length of lines added or the type and size of new transformers.[70] Utilities also can explain why they decided not to take action on any of the worst-performing feeders.[71] These details provide transparency on the strategies utilities pursue and demonstrate how utilities responded to known drivers of poor reliability performance. The information also provides a record of the utility's commitments to improve reliability for accountability purposes.

Utilities also can report on expected reliability improvements from planned remediation actions. California[72] requires that utilities provide a "quantitative description" of expected circuit reliability performance, though in practice much of the utility reporting provides qualitative assessments of reliability improvements.[73]

G6072 **Serving Customers in the Chicago Area - Source Substation: Alsip TSS60**

Engineering Analysis:

G6072 was a 1% CAIDI feeder in 2022 due to one event. The main driver for the activity was a primary wire down during a storm. Planned 1% work will create an overhead tie to reduce outage duration and replace primary wire and poles in poor condition.

Date of Last Tree Trimming	Last Inspection Date Mainline	Last Inspection Date Tap	Estimated Cost of Work	Additional Work Planned and/or Completed
4/20/2023	2/4/2023	2/4/2023	$168,800	Install tap fuse at 1 location, install disconnect at 1 location, install 2 poles, install wildlife protection at 2 locations, install approximately 350 feet of overhead wire, replace 2 poles, reconductor 1 span of overhead wire, replace overhead wire splice at 2 locations, and perform tree trimming as necessary.

Interruption Date	Customers Affected on Circuit	Duration in Minutes	Cause	Cause Detail
1/31/2022	4	190	Public	Dig-in by Others
	1	314		
9/2/2022	12	62	Public	Dig-in by Others
	5	228		
11/5/2022	1	1,116	Tree Related	Limb Broken - Primary
	65	1,125		

Figure 4-1. Worst-performing circuit event history, maintenance history, and remediation plan: Commonwealth Edison[74]

[68] Ameren Missouri, *20 CSR 420-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability report*, 2023
[69] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a
[70] New York State Electric and Gas, *2022 Annual Reliability Report*, 2023
[71] Illinois Commerce Commission, Illinois Administrative Code, 83.1.c.411, 2022
[72] CPUC, Decision Updating the Annual Electric Reliability Reporting Requirements for California Electric Utilities, 2014a
[73] PG&E, *2022 Annual Electric Reliability Report*, 2023
[74] Commonwealth Edison, *2022 ComEd Electric Power Delivery Reliability Report*, 2023a

4.3 Best Practices

Best practices for sharing data on worst-performing circuits include:

- Describe reliability performance metric selection, interruptions excluded from metric calculation, and screening criteria applied to performance data to identify worst-performing circuits
- Provide detailed data on worst-performing feeders:
    - Identifying information for circuits and customers served, by customer class
    - Date, cause, and impact (e.g., customers interrupted, customer hours interrupted) for each reliability event in the reporting year
    - Multiple years of reliability performance metrics and aggregate measures of reliability (e.g., total number of interruptions)
    - Maintenance history (e.g., date of last inspection and tree trimming and description of preventative/mitigation taken in previous reporting years)
- Provide detailed information on remediation plans:
    - Criteria for determining which worst-performing circuits receive remediation plans
    - Description and costs of actions already taken in the reporting year to address poor performance
    - Description, cost, and timeline of actions planned to address poor performance

5. Asset Management Strategy

Asset management encompasses all of the ways utilities make decisions about building and maintaining distribution infrastructure. Asset management spans the full asset life-cycle, from initial equipment selection to design and construction practices to inspection and maintenance and, ultimately, replacement. Most utility infrastructure is expected to remain in service while being exposed to the elements for several decades, which makes both initial construction and ongoing maintenance practices critically important for long-term safe and efficient operation of the distribution system.

Common decision-making elements in executing an asset management strategy include the following:

- *Asset performance:* Assets must be capable of performing their intended function(s) and meeting all applicable codes and standards. For new assets, performance is an important factor in specifying equipment or construction practices. For existing assets, performance is a consideration for inspections and maintenance activities, particularly ensuring public and worker safety.
- *Reliability and resilience:* Maintaining and improving reliability and resilience are core goals for utility spending and, consequently, are central to effective asset management.
- *Efficient budgeting and allocation:* Fundamentally, effective asset management identifies and prioritizes necessary and beneficial activities that maximize benefits for customers while minimizing costs. Balancing short-run and long-run costs against a variety of system needs and potential improvements is the central challenge of asset management.

Asset management may or may not be addressed directly in utility distribution system plans, depending on state requirements and utility practices. In New York, for example, Distributed System Implementation Plans do not explicitly include asset management.[75] Minnesota, in contrast, has an explicit category covering standards, asset health, and reliability management.[76] Regardless of whether utilities provide direct data on asset management in distribution plan filings, underlying asset management practices and methods for selecting and prioritizing investments are important in optimizing resource deployment. Table 5-1 summarizes asset management data and its impacts on distribution system planning.

[75] See Joint Utilities of New York, Distributed System Implementation Plans, 2024 https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips.
[76] Minnesota Public Utilities Commission. Order, in Docket No. E-999/CI-17-879 et al., 2022

Table 5-1. Asset management data categories and impacts

Data category	Type of data reported	Impact of data on planning
Standards and guidelines	Equipment and design standards, engineering guidelines	Shapes physical grid infrastructure and types of solutions available to address system challenges
Asset and reliability data	Reliability indices, equipment testing and inspection data, device settings	Impacts distribution infrastructure and provides opportunities to coordinate asset management with distribution system planning to optimize spending on capacity upgrades
Programmatic asset-related investments	Utility programs and associated goals and budgets	
Discrete asset management investments	Asset needs identification and prioritization	

5.1 Data Inputs

5.1.1 Standards and guidelines: Equipment, construction, and design

Effective asset management starts even before any new equipment is placed in service. Equipment, design, and construction standards and guidelines are foundational to asset management efforts, as they ensure that assets are built in an optimal manner from the start.

Equipment standards and specifications dictate the specific performance requirements of the individual components that make up the distribution system. Specifications may include manufacturer or supplier documents or procurement-related materials used to source equipment. While most equipment specifications are not commonly included in utility distribution plans, they may be impactful to specific equipment replacement programs or grid modernization technologies. For instance, replacing porcelain cutouts with polymer cutouts is an emerging safety and reliability driver for utilities and may be included as part of the distribution plan or as a related investment. For instance, Xcel Energy included a Porcelain Cutout Replacement Program in its Integrated Distribution Plan based on safety improvements and reduction in customer outages expected to result from replacing porcelain cutouts with polymer versions (Figure 5-1).

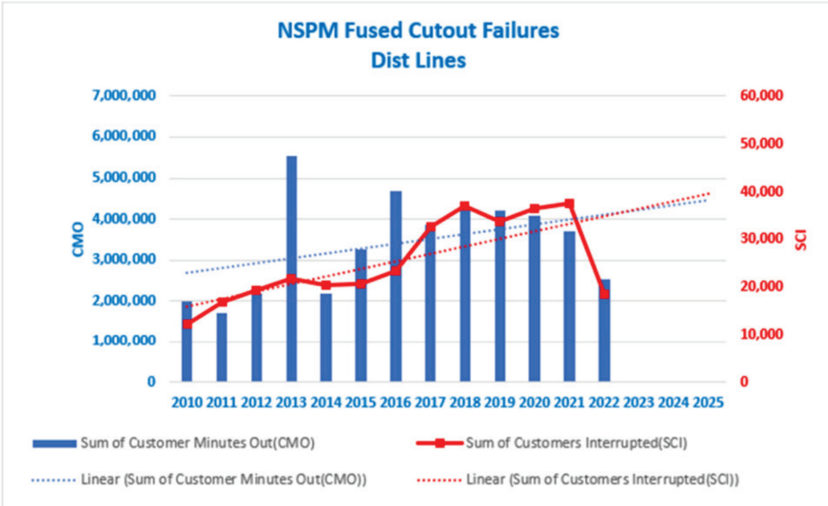


Figure 5-1. Xcel Energy fused cutout failure and customer outage data[77]

Construction standards are the methods and practices of the physical assembly and installation of distribution system equipment. Construction standards also include specific methods and practices for complying with the National Electrical Safety Code (NESC) and other applicable requirements. Specific construction standards are unlikely to be included in utility distribution plans, but broader system-level standards may be included, as they have broad impact on asset performance and cost. For example, Xcel Energy's *Integrated Distribution Plan 2204-2033* in Minnesota detailed the standardized use of NESC Grade "B" construction, which uses stronger poles to withstand more extreme ice and wind loadings.[78]

Engineering and design guidelines are far broader than equipment and construction standards. The guidelines are generally applied as a decision-making guide to balance factors such as cost, performance, and reliability for specific types of decisions across a utility's territory. Utility distribution plans often refer to specific engineering and design guidelines, as they are likely to be associated with new utility programs or changes to spending levels within existing programs. Following are examples of common utility engineering and design guideline topics.

- *Service Transformer Sizing:* Methods and assumptions for selecting service transformer sizes are based on customer load information. Many utilities are revisiting service transformer sizing calculations due to increasing adoption of solar and electrification, as well as increasing data availability through advanced metering infrastructure.
- *Underground Construction Utilization:* These are guidelines for selecting overhead or underground design for new construction in specific areas based on characteristics such as cost, reliability, maintenance, visual impact, or local requirements.
- *Underground Cable* – Repair or Replace: These guidelines are for responding to cable faults that indicate when a fault should be repaired or whether the cable segment should be replaced

[77] Xcel Energy, *Minnesota 2023 Integrated Distribution Plan 2024-2033* – Appendix A2, p 10–11, 2023
[78] Xcel Energy, *Minnesota 2023 Integrated Distribution Plan 2024-2033* – Appendix A2, p 12, 2023

instead. Factors influencing replacement decision-making may include the use of conduit, number of historical faults, accessibility, and replacement urgency.

- *System Voltage Standard Selection:* This guideline applies to the process and justification for standard voltage classes the utility uses for its distribution system. This guideline is included in distribution plans where the utility is pursuing long-term changes in system standard voltage as a result of load growth or standardization to facilitate circuit ties. One common example is converting legacy 4 kV distribution substations to 12 kV.
- *Voltage Conversion Make-Ready:* Where voltage conversion is a long-term goal, make-ready actions can reduce future conversion costs by deploying dual-voltage or higher voltage rated equipment. This may be utilized strategically, as dual voltage equipment is generally more expensive. The most common example is the installation of dual voltage transformers, which prevents the need for future replacement and simplifies the transition cutover process.
- *Storm Hardening:* These guidelines apply to design practices and equipment that provide additional strength or resilience to survive conditions beyond those anticipated and prescribed by the NESC.
- *Wildfire Prevention:* These are guidelines for the design and operation of utility equipment to reduce the risk of wildfires. Wildfire prevention also may be incorporated directly into utility design and construction standards. Common elements for wildfire prevention include use of covered conductors, use of underground equipment, and installation of advanced protective relaying capable of detecting downed conductors.

5.1.2 Data used in asset management decision-making

Because asset management is fundamentally focused on optimization, data related to asset health and performance is a critical input to decision-making. Equipment data, reliability data, and asset health data are all important inputs to analysis of programmatic and discrete investments in asset health. Many of these data streams are reported in utility distribution plans, as they often have wide-reaching impacts on utility budgets, planning, and operations.

5.1.2.1 Equipment data

The most foundational information for asset management is the equipment installed. Location, size, capabilities, age, and connectivity are all important records commonly kept by utilities that serve as the basis for asset management (among other critical activities). Data may be reported in utility distribution plans as aggregate counts of specific equipment such as poles, substations, transformers, or circuit miles of conductor. Utility line devices such as circuit breakers, reclosers, voltage regulators, load tap changers, and capacitor banks have programmable settings and associated utility records. These settings can have impacts on reliability, voltage management, and hosting capacity, among other distribution planning concerns.

5.1.2.2 Reliability and outage data

Asset management practices and investments have major impacts on reliability. Consequently, reliability and outage data are key inputs to making optimal decisions for asset management. Data provided in utility distribution plans may be at the systemwide or regional level, or may be available for specific circuits. Both sets of data are useful in understanding utility and asset performance. Data related to reliability may include metrics such as SAIFI, SAIDI, CAIDI (see Chapter 4: Worst-Performing Circuits for more information on outage metrics). DTE Electric's 2023 Distribution Grid Plan, for instance, included system-level SAIFI, SAIDI, and CAIDI data (illustrated in Figure 5-2) as well as outage cause data (illustrated in Figure 5-3).[79]

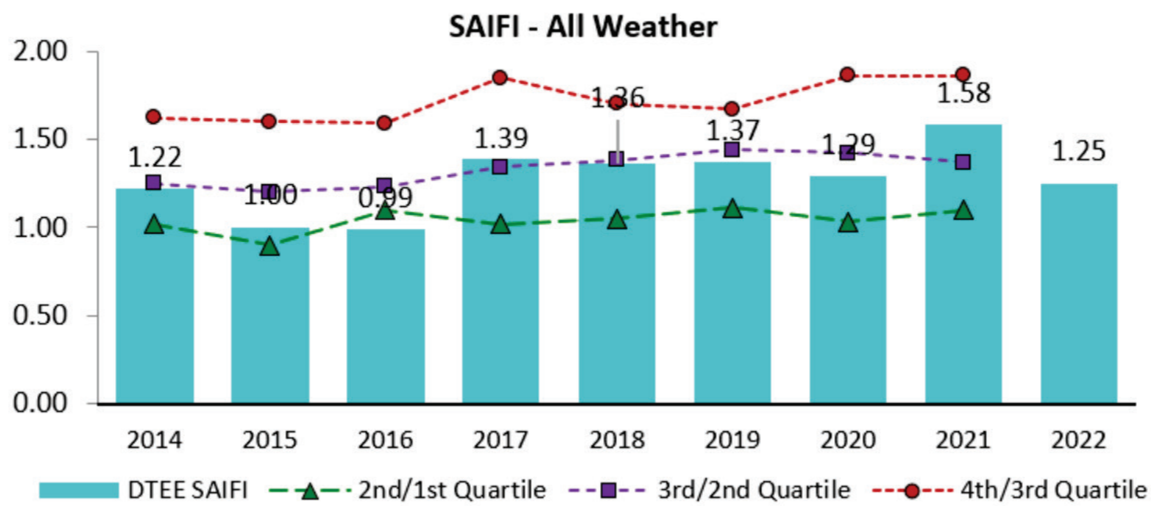


Figure 5-2. DTE 2023 Distribution Grid Plan, historical SAIFI data

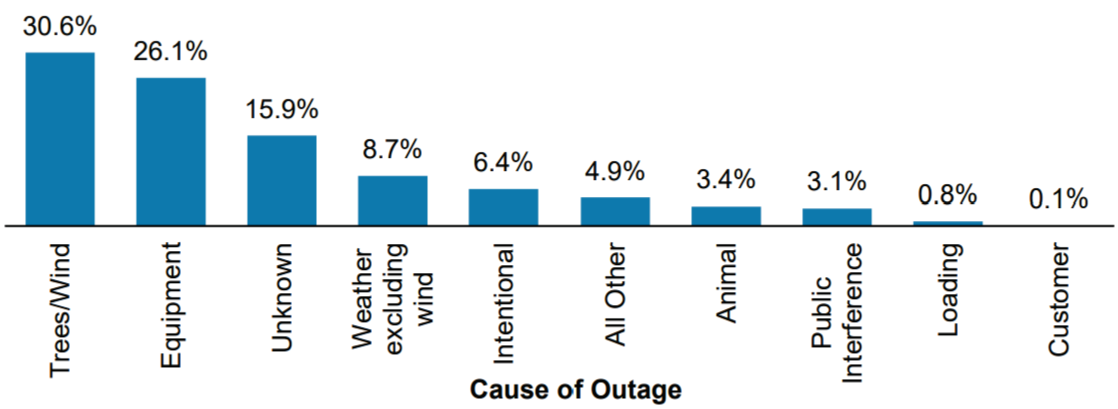


Figure 5-3. DTE Electric Company, 2023 Distribution Grid Plan, five-year average customer interruptions by cause (SAIFI)

5.1.2.3 Asset health data

Asset health refers to the relative risk of failure or nonperformance of a given asset. Because asset failure can have severe consequences impacting public and worker safety, environmental contamination, and reliability, it is generally desirable to replace assets before failure. Asset health data are useful in identifying which assets are at a higher risk of failure. Specific asset health assessment methods and data sources vary significantly depending on the type of equipment being considered, but

[79] DTE Electric Company, 2023 Distribution Grid Plan, pp. 39–41

the overall objectives are to prevent catastrophic failure and enable cost-effective scheduled replacement rather than responding to an emergency.

Most asset health testing and data collection is performed on an annual basis, either for all assets of a certain type or for a subset of assets based on a rotating multi-year schedule. For instance, capacitor banks may be inspected one or more times per year, while a given pole may be inspected every four to twelve years.

Assets that have relatively high costs are often a core focus of asset management programs. In particular, substation transformers, circuit breakers, and regulators are often inspected frequently and more thoroughly than line assets. Testing of the oil within transformers can be used to identify signs of insulation degradation that can indicate elevated failure risk, alongside a host of other testing methods. Other relevant data for health assessment may include asset age, historical loading data (especially whether and how often equipment ratings were exceeded), and the number of circuit faults downline that resulted in high magnitude fault currents. For breakers and voltage regulating equipment, the count of operations or tap movements also can be a strong indicator of health.

For assets that are relatively lower cost and installed at a high volume (e.g., poles), data availability is typically much more limited. Inspections are likely to be much less frequent and also generally do not provide the same degree of information. The frequency of inspections, data collected, and thresholds at which repair and replacement actions are taken are all important facets of asset management for high volume assets.

5.2 Data Outputs

5.2.1 Programmatic asset management investments

Given the scale of utility distribution systems and the high volume of physical assets, it is prudent to organize certain types of spending into programs covering specific activities with associated budgets. Programs that address repeating, ongoing needs are the most common programmatic investments for asset management. Utilities also can develop asset management programs that remediate widespread issues or deploy new technologies over a period of many years due to the cost and scale of deployment. It is relatively common for utilities to include program budget information, new program proposals, or information about changes to existing programs in their distribution plans.

Common utility programs for asset management and grid modernization include:

- Asset Inspections (poles, vaults, manholes, infrared, etc.)
- Animal Guarding and Avian Protection
- Forestry and Tree Trimming
- Underground Cable Replacement
- Lightning Protection
- Porcelain Cutout Replacement
- Communications and Sensor Deployment
- Voltage Optimization
- Advanced Metering Infrastructure Deployment

When considering the scope and budget for new or existing programs, prudency and cost-effectiveness are central concerns. It can be difficult to assess whether program spending is reasonable because the benefits or avoided risks may be spread across wide areas of the distribution system. Consequently, clear information on the drivers of programmatic investments and associated costs are critical factors to evaluate. It also is important to understand how to assess the effectiveness of a given program, including any specific metrics to be used for tracking program impacts.

5.2.2 Discrete asset management investments

In contrast to programmatic investments, discrete asset management investments generally capture specific projects at specific locations that are identified and justified based on reliability, asset health, or safety. Asset management drivers also may contribute to the justification of other system investments, such as distribution planning investments intended to increase capacity. Spending for different types of discrete asset management investments may be aggregated into categories (Table 5-2).

Table 5-2. Capital Expenditure Categories in Xcel Energy (Minnesota) 2023 Integrated Distribution Plan (2023-2027 – $M)

	Bridge Year	Budget					Budget Avg
IDP Category	2023	2024	2025	2026	2027	2028	2024-2028
Age-Related Replacements and Asset Renewal	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4	$227.1
New Customer Projects and New Revenue	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5	$49.3
System Expansion or Upgrades for Capacity	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1	$146.9
Projects related to Local (or other) Government-Requirements	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0	$139.9
Other	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4	$60.7
Metering	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5	$4.5
Grid Modernization and Pilot Projects	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8	$50.6
Non-Investment	($2.1)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8	$27.5
TOTAL	$491.7	$556.5	$548.5	$671.2	$867.2	$1,070.7	$742.8

Utilities generally justify discrete projects individually based on local conditions and investment drivers. As a result, spending within categories can fluctuate year to year based on actual system needs. Consider a substation transformer where routine testing determines that the asset is at a very high risk of failure. The replacement of the transformer may be categorized under "asset renewal" or a similar category, but the spending is driven by the specific needs so it's appropriate to justify it accordingly.

Programmatic investments, in contrast, generally cover a larger geographic area—many are systemwide—and are justified based on aggregate benefits and costs.

Utilities have many different methods for justifying both discrete and programmatic investments related to asset management. Generally, these methods focus on demonstrating the degree of need relative to the cost. That can be used as justification for specific investments or to prioritize a set of proposed investments to maximize benefits. Benefit-cost analyses are a common tool for this purpose. Many utilities also are adopting software tools for asset management and portfolio management that are capable of quantifying value drivers for various investments for prioritization. For example, Ameren Illinois' *2023 Multi-Year Integrated Grid Plan*[80] used the Copperleaf platform[81] (Figure 5-4) for this purpose.

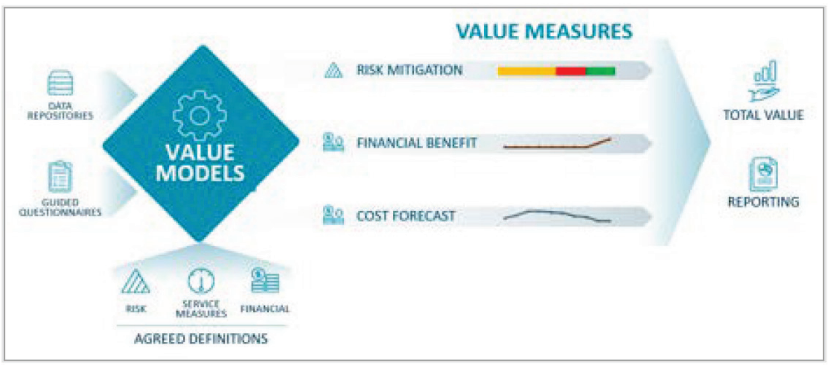


Figure 5-4. Ameren Illinois Multi-Year Integrated Grid Plan Copperleaf value models

5.3 Best Practices

Best practices for sharing data on asset management include:

- Clearly identify standards used to assess asset condition.
- Provide data for programmatic asset management investments to validate that the program is having the intended level of impact.
- Provide data for new programmatic investments to demonstrate the need for the program as well as data that can be reported to demonstrate the program's effectiveness.
- Be transparent about how the utility evaluates asset health and determines when to replace aging assets to provide clarity and support regulatory oversight.
- Share equipment selection and design practices, especially where practices are changing as a result of evolving system needs or environmental conditions, to facilitate efficiency across the anticipated useful life of constructed assets.

[80] Ameren Illinois, *Ameren Illinois' Refiled Multi-Year Integrated Grid Plan*, 2024a
[81] See https://www.copperleaf.com/.

6. Hosting Capacity Analysis

Hosting capacity is the amount (capacity) of DERs, most commonly distributed PV, that can be interconnected to the distribution system without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems. Hosting capacity analysis (HCA) models existing grid conditions and simulates power flow at various levels of DER penetration to determine hosting capacity for generation, battery storage, or new loads such as EV charging.

Hosting capacity maps can serve as a guide for distributed PV developers to evaluate potential project sites. Utilities can use HCA to determine if detailed studies are necessary for interconnection processes. Utilities also can use HCA in distribution system planning to identify the location and causes of distribution system constraints and assess options to mitigate them. In addition, HCA can support estimates of the locational value of DERs.

Key input data for HCA that utilities can share with regulators and stakeholders in the distribution planning process include descriptions of HCA analytical frameworks, distribution system infrastructure attributes, load characteristics, and DER capacity (Table 6-1). Outputs that utilities can share include estimates of hosting capacity for generation, load, and storage as well as results of mitigation analyses.

Table 6-1. Hosting capacity data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Analytical framework	Criteria for updating HCA and key methodological decisions	Provides transparency and enables regulators to validate utility decisions and propose alternatives
Distribution system infrastructure attributes	Locational, technical, and operational information on substations and feeders	Informs siting of DERs and loads absent power flow simulations
Load characteristics	Peak and minimum demand	Informs siting of DERs and loads
DER capacity	Installed and queued DER capacity	Informs siting of DERs and loads
Hosting capacity estimates	Generation, load, and storage hosting capacity	Informs siting, sizing, and operations of DERs and EV charging stations
Mitigation analysis	Options and costs for mitigating constraints	Provides transparency, enables validation of utility analyses, and provides insight into utility investment decisions and potential alternatives

6.1 Data Inputs

6.1.1 Analytical framework

Utilities can document HCA methodological decisions in distribution system plans and describe the costs and criteria for updating their HCA processes. Methodological decisions may include the types of hosting capacity constraints considered, criteria used for identifying each constraint, maximum DER calculation size, and modeling tools used.

Hosting capacity constraints can reflect voltage, loading, and system protection, and inform what changes to project design and what system upgrades are necessary to resolve constraints.[82] For example, Table 6-2 shows criteria that ComEd uses to determine constraints, including a simple description of the criteria that helps nontechnical audiences understand their importance, specific threshold values, and the basis for each constraint. Transparency on the thresholds used for determining constraints enables regulators and stakeholders to understand utility analyses and propose alternatives if relevant.

Table 6-2. ComEd criteria for determining hosting capacity constraints[83]

Criteria	Description	Threshold	Basis
Abnormal Voltage (over voltage)	Voltage exceeds nominal voltage by threshold	105%	Maintain allowable voltage limits per IL Administrative Code Section 410.300
Voltage Variation (Flicker)	Change in Voltage from no DER to full DER (ON/OFF)	3%	Maintain power quality for customers. Eliminate significant voltage fluctuations which may affect power quality to nearby customers and equipment.
Thermal Loading	Element rating	100%	Exceeding these limits would cause equipment to potentially be damaged or fail.
Reverse Power Flow	Reverse Power Flow at voltage regulators and feeders.	0%	Not allowed at voltage regulators and feeder heads to prevent mis-operation due to bi-directional control limitations.

Maximum DER calculation size refers to the amount of DER at which the hosting capacity calculation process will no longer continue to add DERs at a given location. For example, DTE Energy established a maximum calculation DER size of 2 MW.[84] A relatively common maximum size cutoff for medium voltage (e.g., 12.47 kV) distribution systems is 10 MW. Ameren Illinois[85] and Xcel Energy,[86] among others, use this threshold. These caps establish the upper limit for hosting capacity at a given location. DERs larger than this size may still apply for interconnection, but will have more limited information available from the hosting capacity map.

[82] Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022
[83] ComEd, Multi-Year Integrated Grid Plan, 2023
[84] DTE Energy hosting capacity map, n.d.
[85] Ameren, Ameren Illinois Refiled Multi-Year Integrated Grid Plan – Hosting Capacity, p 235, 2024b
[86] Xcel Energy, 2024 Hosting Capacity Program Guidebook, 2024

Utilities can identify and describe the tools they use in HCA. In its 2023 Integrated Distribution Plan in Minnesota, Xcel Energy provided a table that maps tools to planning activities, including HCA, and explains the capabilities and uses of each tool.[87] Such information helps regulators and stakeholders understand workflows and relate utility practices to industry best practices. The choice of software tool can impact the use cases that HCA can enable. For example, tools with stochastic modeling capabilities add incremental DERs of varying sizes at varying locations within the model until hosting capacity criteria are violated and then repeat this many times using Monte Carlo analysis. While stochastic modeling tools provide useful information for distribution planning, such as a wide range of possible outcomes, including those related to DER adoption, and the likelihood of various scenarios occurring, other tools can better support interconnection-focused use cases. Tools with iterative modeling capabilities, which add increments of DERs at a specific location until hosting capacity criteria are violated (repeated for all locations), can provide information much more geared toward supporting interconnection.[88]

Given the effort required, utilities may update HCA for only a subset of feeders each year. In HCA reports, utilities can describe the criteria used for selecting feeders for updates. Xcel Energy,[89] for example, includes feeders in quarterly HCA updates if the feeder's hosting capacity has not been updated in the previous 12 months and one of the following criteria is met:

- Load has increased or is expected to increase by 500 kilovolt-amperes (kVA) within one year
- Newly installed DER capacity totals at least 100 kW
- Feeder capacity or configuration has changed or will change due to projects in the next year

Providing such transparent criteria helps regulators and stakeholders know what HCA updates to expect and facilitates consideration of alternative criteria.

In addition, utilities can report the cost to update HCA. Pursuant to an order from the Minnesota PUC, Xcel Energy's 2022 hosting capacity report provides estimates of staffing costs if the utility updated HCA monthly using its existing process, compared to the net cost of modeling upgrades considering labor cost savings through automation.[90] Such detailed cost data can help regulators determine whether modeling upgrades may be appropriate. That includes consideration of expanded HCA functionality, such as its use for interconnection, one of the motivations for consideration of monthly updates in Minnesota.[91]

6.1.2 Distribution system infrastructure attributes

Table 6-3 summarizes the characteristics of substations and feeders that utilities can report in hosting capacity maps and downloadable tables. Utilities use these data as inputs to simulations of the

[87] Xcel Energy, Integrated Distribution Plan, Table A1-2, 2023a
[88] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[89] Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022
[90] Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022
[91] Xcel Energy Minnesota, 2022 Hosting Capacity Program Report, 2022

distribution system to estimate hosting capacity values. The data also can inform siting of DERs before a utility performs power flow simulations.[92]

Table 6-3. Substation and feeder characteristics[93]

Characteristic	Substation	Feeder
ID/name	X	X
ID/name of substation/feeder it is connected to	X	X
Location (coordinates)	X	X
Count of substation transformers	X	
Number of customers by customer class	X	X
Has known transmission constraint	X	X
Recent upgrades	X	X
Planned upgrades	X	X
Voltage(s)	X	X
Transformer nameplate rating	X	X
Has protection/regulation	X	
Has been upgraded for reverse flow	X	
Bus-tie exists	X	
Type (e.g., radial, network, mesh, spot)		X
Length		X
Voltage		X
Number of phases		X
Conductor capacity		X
Service transformer rating		X

6.1.3 Load characteristics

Utilities can provide data on minimum and peak demand for locations of the distribution system for which they are estimating hosting capacity. Minimum demand values vary by hour of the day (daytime vs. all hours) and time period (year vs. month). Daytime minimum demand, whether annual or monthly, can inform PV site selection and operation because generation during periods of low demand are more likely to cause voltage or other issues. Providing daytime minimum demand on a monthly basis can enable PV or other DER projects that can adjust exports to the grid throughout the year. Annual

[92] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[93] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021

reporting provides the minimum load data from the month with the lowest demand.[94] Increasing the granularity of hosting capacity data can facilitate improved DER sizing for applications.

Providing minimum demand data for all hours in a day can inform siting of battery storage paired with PV as well as distributed generation technologies that, unlike PV, can produce power outside of daytime hours.[95] For example, Xcel Energy in Minnesota provides both daytime and absolute minimum demand in its hosting capacity map, enabling developers to make informed decisions about siting, sizing, and operating distributed generation and storage technologies.[96]

Historical and forecasted peak loads can inform site selection for new loads such as EV charging. For example, Con Edison provides peak load (MW) in its load hosting capacity map, and Rhode Island Energy provides peak load for the previous year and for 10 years forecasted into the future.[97] [98]

Instead of single-hour demand values such as minimum and peak load, utilities can share an hourly load profile for an entire year (8,760 hours), load profiles for the two days in each month when peak and minimum demand occur (576 hours), or monthly peak and minimum load values. San Diego Gas & Electric (SDG&E), for example, provides monthly peak and minimum load values within its Integration Capacity Analysis tool (Figure 6-1).

Figure 6-1. Monthly peak and minimum load chart example – SDG&E[99]

6.1.4 DER capacity

HCA data for DERs can include installed and queued generation capacity or the number of applications in the study queue. Such information indicates the penetration of DERs in that area, as well as the

[94] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[95] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[96] Xcel Energy, Minnesota, hosting capacity map
[97] Con Edison, Hosting Capacity Web Portal
[98] Rhode Island Energy, System Data Portal
[99] SDG&E, Interactive Map and ICA User Guide

potential timeline for queued studies still to be processed. Figure 6-2 shows how DTE Energy indicates the queued and installed DER capacity in its hosting capacity map.[100]

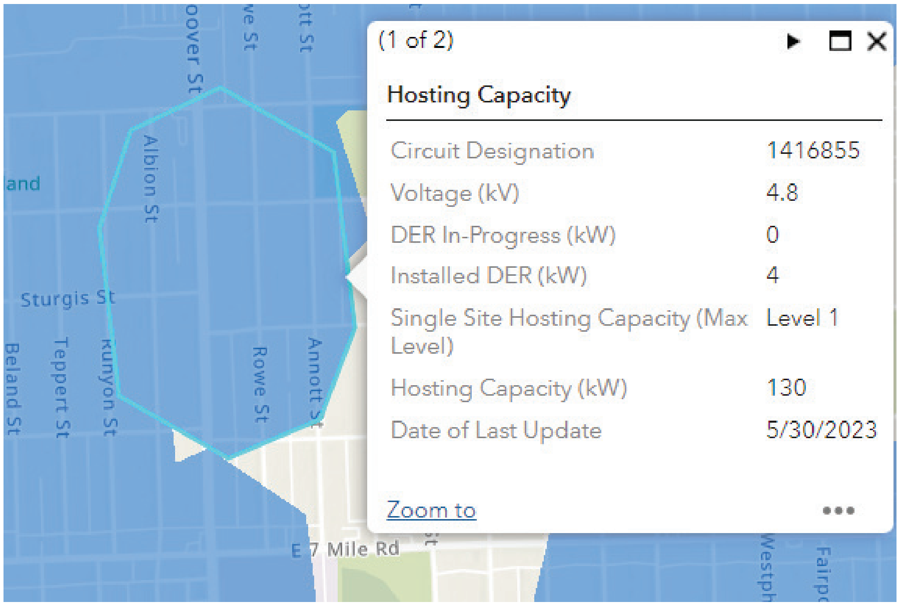


Figure 6-2. Queued and installed DER capacity in DTE Electric Company hosting capacity map

6.2 Data Outputs

6.2.1 Hosting capacity estimates

Utilities can provide hosting capacity estimates for generation, load, and energy storage. Utilities can publish these data in maps (see Figures 6-2 and 6-3), which can reduce the volume of data requests to utilities and help developers and customers access data relevant to their projects. Downloadable tabular data can complement the maps and can support analysis. Xcel Energy, for example, provides feeder and node level results in a machine-readable tabular format.[101] Central Hudson, while not providing direct downloadable tabular versions, enables tabular export of data using built-in ESRI map capabilities.[102] Application programming interfaces, such as those hosted by Con Edison and other New York investor-owned utilities, also can support analysis and help developers incorporate hosting capacity data into their own processes.[103] [104]

Similarly, utilities can share geographic data underlying HCA maps, which project developers can incorporate into their own geographic systems.[105] Utilities can report each type of hosting capacity for nodes within the feeder's footprint (Figure 6-2) or at the feeder level (Figure 6-3). Sub-feeder-level

[100] DTE, Energy hosting capacity map
[101] Xcel Energy, Hosting Capacity Resources, https://mn.my.xcelenergy.com/s/renewable/developers/interconnection.
[102] Central Hudson, Hosting Capacity Map
[103] Interstate Renewable Energy Council, Key Decisions for Hosting Capacity Analyses, 2021
[104] Con Edison, REST Services Directory
[105] Con Edison, REST Services Directory

data can support more targeted deployment of DERs and help developers assess specific interconnection points.

Figure 6-2 is a hosting capacity map for Xcel Energy in Colorado. For this feeder node, unintentional islanding is the most constraining hosting capacity criteria to 0.47 MW. The overvoltage criteria is the "maximum" because it is the last constraint to be violated during the iterative hosting capacity calculation process. In this example, 10 MW is the maximum DER size considered within the study and does not necessarily result in a violation of the overvoltage criteria. Transparency into the factors that constrain hosting capacity helps developers understand whether and which system upgrades will be necessary to enable DER projects of varying sizes.

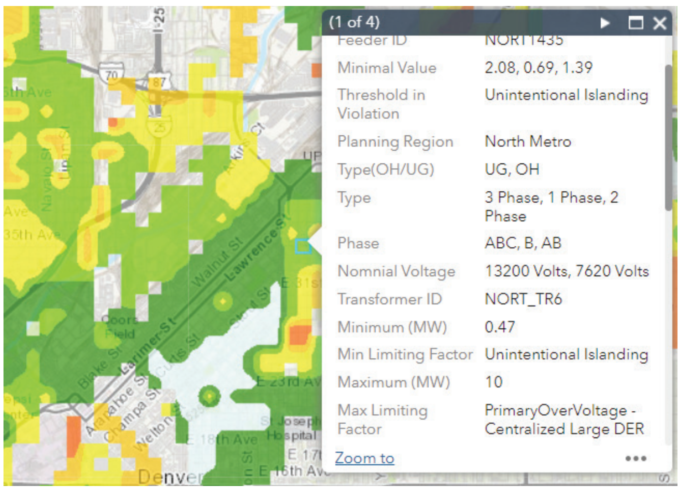


Figure 6-2. Xcel Energy, Colorado generation hosting capacity map and data pop-up window

Load hosting capacity data can include capacity available for EV charging, as well as building electrification. For example, Con Edison provides load hosting capacity for transformers and feeders for both EV charging and building electrification (Figure 6-3).[106] Hosting capacity values for individual service transformers inform site-level restrictions, and feeder and substation hosting capacity values for both summer and winter support decisions for larger developments. The utility's hosting capacity values represent the difference between seasonal peaks and rated capacity of the equipment.

Hosting capacity varies by season due to differences in load and equipment capacity. At colder temperatures, loading capacity of distribution system infrastructure increases. Load hosting capacity maps can show specific values for feeders and transformers (the lines and circles in Figure 6-3) or provide ranges (e.g., 0.5–1 MW).[107] Ranges can be helpful guides, but specific hosting values for distribution system equipment better support decision-making.

[106] Con Edison, Con Edison Hosting Capacity Web Application
[107] Delmarva Power, Available Load Capacity Map

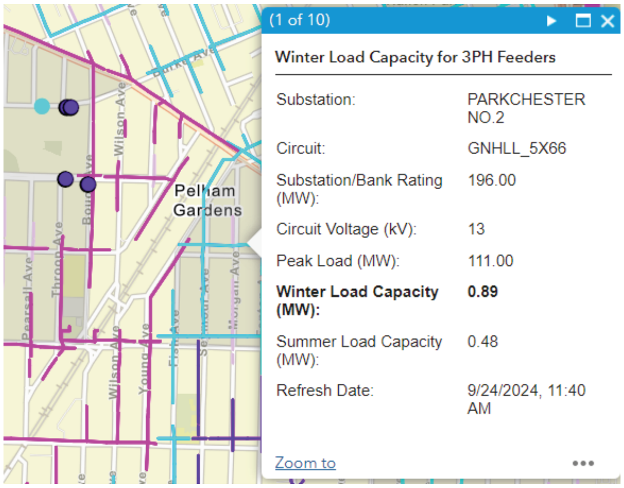


Figure 6-3. Con Edison load hosting capacity map and data pop-up window[108]

New York investor-owned utilities are among the few U.S. utilities that provide hosting capacity information for energy storage systems.[109] These New York utilities publish hosting capacity maps for storage separately from those for generation and load hosting capacity. Orange & Rockland Utilities, for example, publishes a map with hosting capacity for both storage charging and discharging.[110]

For all types of hosting capacity results, utilities can report the date that they last updated the data (see Figures 6-1 and 6-3). The more recent the data, the less likely a developer will confront unforeseen issues due to changes in distribution system components, load, or installed capacity of distributed generation or storage at the intended point of interconnection.

Utilities also can report data on HCA accuracy. For example, the California Public Utilities Commission recently required Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison to provide biannual HCA reports that identify issues with HCA accuracy or data completion and describe plans and timelines for correcting the issues.[111] Discrepancies between HCA and interconnection study results for specific loads or DERs also can point toward potential improvements.

6.2.2 Mitigation analysis

Mitigation analysis identifies constraints to hosting capacity and considers strategies to address these constraints. Utility HCA reports can delineate mitigation options and costs and provide estimates of increased hosting capacity that result from mitigation. Xcel Energy in Minnesota, for example, summarized potential mitigation strategies to address a range of common constraints for generation hosting capacity (Table 6-1). Such documentation provides transparency into the utility's decision-making process and helps regulators and stakeholders understand options available for increasing hosting capacity. The utility also reported the range of costs for mitigation and interconnection for DERs

[108] Con Edison, Con Edison Hosting Capacity Web Application
[109] DOE, Atlas of Electric Distribution System Hosting Capacity Maps
[110] Orange & Rockland Utilities, Hosting Capacity Web Application
[111] CPUC, Rulemaking 21-07-017, 2024

1–5 MW ($50,000–$1.4 million), noting that it is generally less costly to manage voltage constraints by adjusting inverter settings than to mitigate thermal issues.[112] Such cost information can help regulators and stakeholders understand which constraints to prioritize with limited resources and help developers understand expected utility system upgrade costs when different types of constraints are exceeded.

Table 6-1. Xcel Energy, Potential Mitigations to Increase Generation Hosting Capacity[113]

Category	Impacts	Mitigation
Voltage	Over-voltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

6.3 Best Practices

Best practices for sharing data on hosting capacity analysis include:

- Identify the maximum DER size considered in the analysis
- Document types of constraints considered and the threshold for each constraint
- Publish publicly-available maps that present node-level data on:
    - Substation and feeder characteristics
    - Installed and queued DER capacity
    - Historical and forecasted peak demand
    - Daytime and absolute minimum demand
    - Generation, load, and energy storage hosting capacity
    - Underlying geographic information
    - The constraint that limits hosting capacity
    - Date of last update
- Document issues with hosting capacity accuracy and plans to correct those issues
- Offer a tabular version of mapped data or an application programming interface that enables access to the data in a usable form
- Identify strategies and costs to mitigate hosting capacity constraints, including no- and low-cost options
- Describe criteria and costs for updating modeling tools and capabilities and updating hosting capacity analysis on a more frequent basis

[112] Xcel Energy, Minnesota, Reply Comments to 2019 Hosting Capacity report, 2019
[113] Xcel Energy, 2024 Hosting Capacity Program Guidebook, Table 3

7. Value of Distributed Energy Resources

Value of DER, as a concept, is an attempt to more accurately account for the benefits of DERs to the power system, especially at the distribution system level where there are no existing market structures. One of the objectives of valuing DERs in distribution planning is to direct DER deployment to areas that improve distribution system outcomes or prevent or defer future investments.

Currently, implementation of rates and compensation structures based on the value of DERs is limited. The majority of the work to date has been in the form of state-level value of DER studies, which attempt to quantify the value of different types of benefits such as capacity, loss reduction, and voltage support.

Valuing DERs is an important building block for enabling these resources to provide distribution services and be effectively compensated. It is particularly critical for energy storage, where there is significant potential value that is not realized or effectively compensated by traditional Net Energy Metering frameworks. Whether and how DER value is considered, calculated, and incorporated is part of a broader consideration of how DERs are integrated in distribution planning and investment processes.

Generally, DER value is derived by quantifying costs that are avoided as a result of the expenditure that would otherwise be incurred by the utility. Other benefits also may be included, with magnitudes based on the cost to achieve the benefits using other available means. Fundamentally, valuing DERs aims to provide utilities with another way to meet system needs, and is thus closely tied to key distribution system planning (DSP) elements, including distribution system planning, load and DER forecasting, and investment justification. Table 7-1 summarizes value of DER data that can be included in distribution system plans and its impacts on planning.

Table 7-1. Value of DER data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Distribution system input data	Distribution growth expectations, capacity needs, and historical costs	Informs DER programs, which can affect future distribution system planning needs
DER input data	DER types and associated performance characteristics	
Distribution DER value drivers	Value drivers considered and corresponding quantification methodologies	

7.1 Data Inputs

Value of DER studies can cover one or more types of DERs active in a utility's distribution system. Single-technology studies can reduce study complexity and address specific planning needs. For example, a Value of Solar study was performed for the Minnesota Department of Commerce[114] to inform a Value of Solar tariff for investor-owned utilities.[115] However, studies capturing only one technology type may use methods or assumptions that can be difficult to generalize or apply more broadly because specific performance characteristics of the technology (e.g., solar resources producing energy during daylight hours) are embedded within the process. Technology-agnostic studies, in contrast, use generalized methods that provide a flexible base to which different types of DER and performance characteristics can be applied to determine the value of a specific type of DER.

Regardless of the set of DER technologies studied, utilities can report on performance characteristics of each DER, including the operating profile, use of autonomous smart inverter functions, lifespan, and monitoring and control capabilities. These characteristics have a significant impact on the value calculations performed in the study and the ability of a DER to provide value after installation.

Operating profiles describe the timing and magnitude of DER electricity resource production, consumption, or storage. For solar PV, utilities can provide a time series of expected power generation and document data sources. For example, a 2022 New Hampshire study[116] used ISO-New England production profile data with NREL's PVWatts[117] generation profiling tool.

Because distribution needs are often limited to specific hours of the year (e.g., hours of peak load), the timing and magnitude of DER operation within the operating profile have significant impacts on the resulting value. For event-driven DERs such as demand response, utilities may identify the specific program or control mechanism that will be used to align DER performance with local needs. Central Hudson's Peak Perks Program in New York[118] provides one such example. Because distribution needs vary in time and may not fully coincide with bulk power system needs, aligning DER performance is critical to providing distribution system value.

Autonomous smart inverter functions can impact overall performance and DER value by providing additional voltage support. DERs with volt/volt-amps reactive (VAR) curve functionality are particularly effective, as they can modify their reactive power setpoint in response to local voltage conditions to help mitigate voltage violations. Volt/watt curves also may be used to address overvoltage challenges, but they involve greater risk of real power curtailment and subsequently are less commonly used. For example, New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E) require the volt/VAR curve points in Table 7-2, but do not use volt/watt functionality. Utility reporting on smart

[114] Norris, Putnam, and Hoff, *Minnesota Value of Solar: Methodology*, 2013
[115] State legislation enabled use of the tariff as an alternative to net metering and as a rate that can be used for community solar gardens.
[116] Dunsky Energy + Climate Advisors, *New Hampshire Value of Distributed Energy Resources: Final Report*, No date
[117] NREL, PVWatts® Calculator
[118] Central Hudson, Peak Perks

inverter functions using the associated curve points help regulators and stakeholders understand how DERs can support voltage and corresponding value.

Table 7-2. NYSEG and RG&E Volt/VAR Curve[119]

Volt-VAR[2]

Volt-VAR Active	Yes
Vref	1
V1 - [pu]	0.93
Q1 - %Nameplate Apparent Power Rating	0%
V2- [pu]	0.97
Q2 - %Nameplate Apparent Power Rating	0%
V3 - [pu]	1.03
Q3 - %Nameplate Apparent Power Rating	0%
V4 - [pu]	1.07
Q4 - %Nameplate Apparent Power Rating	-44%

[2] (+) Q Values Indicate Injection of Reactive Power (VARs) from the Inverter onto the Area EPS (-) Q Values Indicate Absorption of Reactive Power (VARs) from the Area EPS to the Inverter

The time period considered in Value of DER studies is another critical aspect that can significantly influence value calculations. The period may be aligned with forecasting time horizons for utility distribution system plans (e.g., five to ten years) or with the expected DER lifespan for longer-term value considerations. A recent study for the District of Columbia Public Service Commission,[120] for example, incorporated valuation estimates through 2045. Considering longer time horizons tends to increase the resulting calculated value because DERs provide services for additional years. Because the studies rely on forecasts and assumptions, however, adding years further into the future also tends to increase the risk of inaccuracies.

The ability to collect and use real-time and historical performance data in planning processes can reduce the number of assumptions, which often reflect worst case scenarios. Replacing assumptions with actual data leads to a more accurate understanding of system needs and improves investment efficiency. The ability of utilities to directly control solar generation and storage, for example, to align DER operations with local grid needs can enable much more effective use of DERs as a capacity resource. Hawaiian Electric's Bring Your Own Device Program[121] enables a variety of customer resource types, including battery storage systems and smart thermostats, to be dispatched by the utility to align with distribution and bulk power system needs for capacity.

[119] NYSEG and RG&E IEEE 1547-2018 Default Smart Inverter Settings, 2023
[120] Kallay, J. et al., *A Value of Distributed Energy Resources Study for the District of Columbia: Framework, Impacts, Key Findings, and Roadmap*, 2023
[121] Hawaiian Electric, Bring Your Own Device Program, 2024

7.1.1 Types of DER value and services to the distribution system

Utilities can identify the specific drivers they consider, describe the method(s) by which the value can be quantified, and report calculated values. Table 7-3 defines the types of values utilities can report in distribution system planning.

Table 7-3. Types of values utilities can report for value of DER studies and distribution system plans

Value driver	Definition
Distribution capacity	DERs delay or avoid the need for distribution capacity upgrades by reducing peak demand.
Loss reduction	When generated energy is consumed locally, DERs can reduce energy lost in electricity transmission and distribution.
Voltage support (power quality)	DERs can increase local voltages in low voltage areas and help modulate voltages using smart inverter functions.
Increased hosting capacity	DERs capable of acting as controllable loads can absorb excess solar generation, allowing for additional solar energy to be generated or additional distributed PV systems to interconnect.
Reliability, resilience, and outage reduction	Certain types and configurations of DERs can act as an alternate source during system outages, improving reliability and resilience.
Operations and maintenance (O&M) spending reduction	Utilities engage in a wide range of operations and maintenance activities that may be positively impacted by DERs.
Asset health	DERs can reduce the loading on equipment, which may increase equipment lifespan or reduce failure risk.
Other DER impacts	DERs may have positive impacts across nontechnical considerations including societal, environmental, and other benefit streams.

Specific services and methods vary by jurisdiction and study methodology. Distribution capacity is the most common DER service considered. Utilities can calculate distribution capacity value of DERs in either the short-run or long-run. *Short-run capacity value* refers to specific capacity upgrades expected to be necessary at specific locations within the utility's distribution planning forecast time horizon (e.g., 5–10 years). DER value for such locations is based on the magnitude of the capacity investment and the number of years it can be deferred through DER-derived capacity. *Long-run capacity value* refers to capacity-related investments that may become necessary but are not currently included in the forecast. These types of capacity needs may result from deviations from the utility forecast or occur beyond the forecast window. Whether the utility uses short-run or long-run values, or both, when determining distribution capacity value significantly affects the magnitude and locational nature of any resulting customer incentives.

Other potential value drivers span system efficiency, reliability, power quality, and maintenance, among others. Specific methods for quantifying and incorporating these value streams are still nascent, as they tend to be even more location-driven than capacity and often have less supporting information available to quantify the potential DER impacts.

Figure 7-1 illustrates Commonwealth Edison's marginal cost of service study process for its Grid Plan. Table 7-4 provides marginal cost results from Ameren Illinois' Grid Plan for a range of assumptions.

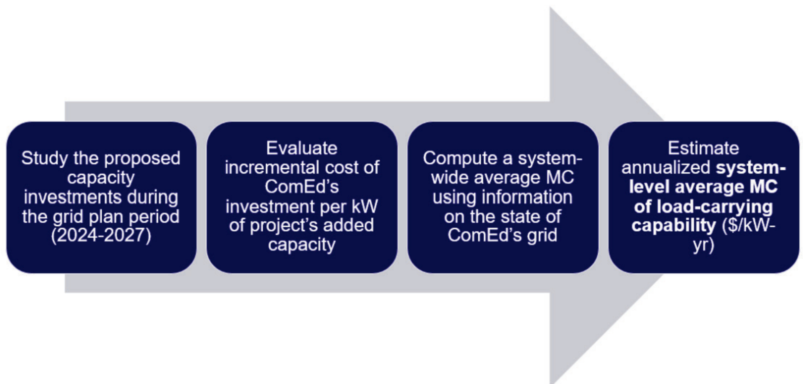


Figure 7-1. Commonwealth Edison's marginal cost of service study methodology[122]

Table 7-4. Ameren Illinois marginal cost results[123]

Marginal Cost Analysis (2023 Dollars)	Low Range	Mid Range	High Range
Total capacity-related annualized marginal cost ($/kW-year)	$6.81	$11.46	$21.75

Reduced line losses

When energy produced by DERs is consumed locally, it does not travel across transmission and distribution infrastructure components. That reduces energy losses and associated costs. When energy produced by DER is exported to the utility system, impacts to energy losses are more complex to evaluate and depend on local system loads and configurations. Changes in energy losses due to DERs are an important consideration in assessing DER value. It is difficult to assess these changes at a system level, given the high degree of variation in DER location. Modeling at a smaller scale and analytical calculations can provide estimated results for various locations.

Voltage support

Utilities can use DER real and reactive power capabilities to help regulate distribution system voltages and prevent voltage conditions outside of the standard operating range. Smart inverter capabilities

[122] ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 50, 2024. The study resulted in a marginal cost per kW of peak load of $5.54/kW-year.
[123] Ameren Illinois, *Ameren Illinois' Refiled Multi-Year Integrated Grid Plan,* Appendices P-W, p. 136, 2024c

such as volt/VAR curves are particularly impactful at providing voltage support. Because DERs also can create voltage issues, DER value analysis can identify voltage issues are “self-inflicted”—those result from DER operations—and separate them from system-driven voltage issues where DERs are providing only positive support.

Quantifying the value of voltage support from DERs is often difficult. First, utility historical data on voltage violations is often limited to customer complaint information. Advanced metering infrastructure measurements that include meter voltage provide an opportunity to examine the location, frequency, duration, and severity of voltage violations, but even with these data available there are challenges to ensuring accuracy and consistency. Second, performance of DERs varies, and they may not be fully capable of replacing traditional voltage management equipment (voltage regulators or capacitor banks) if the DER (e.g., solar) is not producing during some periods of voltage violation.

Increased hosting capacity

Battery storage, when operated for such a purpose, can charge from excess solar capacity and discharge to the grid during periods of higher load, effectively increasing hosting capacity. Voltage support and data access also can increase hosting capacity. Analysts can take care not to include benefits for avoiding constraints that the DERs themselves otherwise might cause.

Reliability, resilience, and outage reduction

The ability of DERs to improve reliability and resilience, by avoiding or shortening sustained outages, is heavily dependent on specific DER design and other technologies. DERs that are configured as part of a microgrid that segments a portion of a distribution system (“islanding”) may provide value that is considered beneficial to society and customers within the microgrid boundary. Several examples have been developed by utilities and communities.[124] [125] DER value related to islanded microgrid operation in such a configuration can be carefully considered alongside the feasibility, additional costs, and overall benefits of implementation in a given area.

However, behind-the-meter DERs that are configured as part of a customer’s microgrid, or that provide stand-alone backup power (e.g., onsite generator or battery) to their premises or campus, are typically not considered to provide benefits to other customers.

Operations and maintenance (O&M) spending reduction

Utility spending on operations and maintenance activities covers a relatively broad set of activities, some of which may be impacted by DERs. Considering reduction in O&M spending as a potential value driver requires identification of specific cost drivers and specific mechanisms that enable DERs to avoid those costs. DER operation also may increase O&M costs, such as load tap changer operations and

[124] ComEd, Bronzeville Microgrid. https://www.energy.gov/eere/solar/project-profile-commonwealth-edison-company-shines
[125] Portland General Electric and City of Beaverton, Beaverton Microgrid. https://blog.energytrust.org/wp-content/uploads/2022/05/BeavertonPublicSafety_CS_05_2022_web.pdf

maintenance, due to increased operations from voltage fluctuations.[126] Any identified cost reduction will need to be netted against any increased costs.

Asset health

Asset health generally refers to the risk of failure of a given asset and the overall asset service lifespan. DERs can reduce the degree of loading on an asset, which may reduce risk of failure or extend asset lifespan, though there are limited data on the overall size of this effect. Conversely, DERs may negatively impact asset health, affecting DER value. For example, voltage regulators may experience increased tap operations due to DER adoption, though there are techniques and technologies (with associated costs) to reduce these effects. As a result, quantifying DER impacts on asset health is challenging.

Other DER impacts

If value streams beyond the distribution system are considered, they may be identified along with corresponding quantification methods and supporting information. Table 7-5 provides an example from Commonwealth Edison's Grid Plan in Illinois.

Table 7-5. Commonwealth Edison DER costs and benefits[127]

Impact Category	Timeline	Costs	Benefits
DER Owner	Short-Term	Interconnection costs, Equipment costs and financing, Electrical upgrade costs, Permits and Inspections	Reduced Energy Costs, Net Metering, Rebates/Tax Credits
	Long- Term	Changing Tariffs and Energy Costs	Wholesale Market Participation, Customer Back Up (resilience benefit)
Environmental	Short-Term	Upstream Manufacturing Emissions	Greenhouse Gas Emissions Reductions, Air Quality Improvement
	Long- Term	DER Recycling and Disposal	Reduction in Climate Change Impacts
Societal	Long- Term	Renewable Energy Credits	Environmental justice Health benefits associated with air quality improvements. Green/Sustainable living
Generation & Transmission	Short-Term Long-Term	Implementation and Management Costs for Wholesale Market Access, Transmission Modeling and NERC Compliance Costs	Wholesale Services (Energy, Capacity and Ancillary services)
Distribution Grid	Short-Term	Hosting Capacity Infrastructure Grid Investments, and DER Rebates	Distribution Capacity relief, Line loss reduction
	Long- Term	DER management and coordination	Outage support & resiliency, Voltage support

As illustrated in the example above, it is important to differentiate between positive DER contributions that impact the broad distribution system and positive DER contributions that benefit the DER owner or future DER interconnections, or which serve to offset otherwise detrimental system impacts of DER.

[126] A tap operation occurs when a voltage regulator adjusts the line voltage, and the physical connection in the regulator is moved from one position to another. Fluctuations in DER output can impact system voltages and result in additional tap operations.
[127] ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 42, 2024

Identifying the beneficiaries within each value stream is critical to ensuring the benefits are accounted for and allocated fairly across those impacted.

7.1.2 Distribution system input data

To understand the potential for DERs to provide value to the distribution system, it is critical to understand current system conditions, forecasted system growth and changes, and existing and future grid needs.

Grid needs assessment

The data within a grid needs assessment typically covers known and anticipated capacity, reliability, and other challenges for the distribution system. Fundamentally, the value of DERs is derived from their ability to address grid needs. Data related to grid needs are often presented across many different sections of utility distribution plans.

Long-term forecasts and expected system changes

Load and DER adoption forecasts are an important input to understanding future grid conditions. Typically, distribution plans contain forecasts for 5–10 years for assessing grid needs. When considering the DER value, it may be necessary to look further ahead to capture future needs that may be addressed by DERs. With DER lifespans in the range of 20 years or more, developing accurate forecasts for the entire period is difficult. Still, it is important to consider future expected conditions using the best information available.

Marginal cost of capacity

The marginal cost of utility distribution capacity can be used to evaluate and quantify future capacity contributions and their value. Marginal cost calculation methods may use short-term and long-term forecasts as an input. Regulators can consider providing guidance to utilities for including specific marginal cost study documents or results in filed distribution system plans.

Asset health information

Information about assets that make up the distribution system is important to understanding grid needs and optimizing investments across different options, including potential value provided by DERs. As an example, deferring a substation transformer replacement by using DERs to provide additional capacity may be highly cost-effective if the transformer is in good condition. On the other hand, if the transformer is already at a high risk of failure, it may be more cost-effective to replace the transformer instead. Asset health information is often included in distribution plan filings in some form.

Voltage support needs

Understanding existing voltage challenges and locations with voltage violations can be important for understanding DER value. Often, mitigation efforts for voltage violations involve lower-cost equipment, which may not be captured in distribution plan filings. Data related to customer voltage complaints may be more readily available, but is unlikely to capture all voltage needs.

Key Challenges with Value of DER in Distribution Planning

When reviewing data and methods in distribution system planning for determining DER value, some key challenges can make it difficult to assess the quality of information provided. Being aware of these challenges and engaging with utilities on these issues can help facilitate a constructive dialogue.

Scarce Content on Value of DER in Distribution System Plans

Valuation of DERs is not yet commonly practiced in the electric utility industry, and many utilities do not include value of DER considerations in distribution planning filings. Even in states such as New York, with a Value of Distributed Energy Resources rate offering to customers,[1] relevant inputs and assumptions for each utility's value of DER offering are provided separately from the distribution planning process. Guidance to utilities on proactive engagement and reporting with respect to value of DERs may be necessary to ensure relevant content is addressed in filed distribution system plans.

Methodology and Assumption Differences

Types of DER values considered, methodologies to calculate those values, and underlying assumptions—all of which can significantly impact valuation results—vary widely across jurisdictions. While there are leading practices and examples,[1] many aspects of determining the value of DER have yet to be conclusively settled. Marginal cost study methods, discussed above, are one such example, where methodological differences can have significant impacts on resulting DER value calculations.

Geospatial Granularity

A key decision for valuing DERs is the extent to which benefits are assessed (and in some cases compensated) based on their specific location. System-level methods, which do not vary benefit calculations or compensation by geographical location, are common. They result in consistent results but may overestimate or underestimate actual benefits for a given DER being interconnected at a particular location on the grid.

Incorporating more geographic granularity into the analysis—at the feeder/substation or point of interconnection level—can better match DER value to areas of need, increasing DER value for installations in locations where it provides greater benefits and decreasing DER value for installations in locations where it provides lower benefits. This approach can drive additional efficiency in resource deployment but comes with significantly more complexity. Consider the potential of DERs to reduce line losses. Figure 7-2 illustrates how variations in DER location can impact line losses. Geographic granularity can lead to two different customers installing the same type of DER system receiving differing levels of compensation, which can raise issues of fairness. Balancing these factors is an element of success within Value of DER.

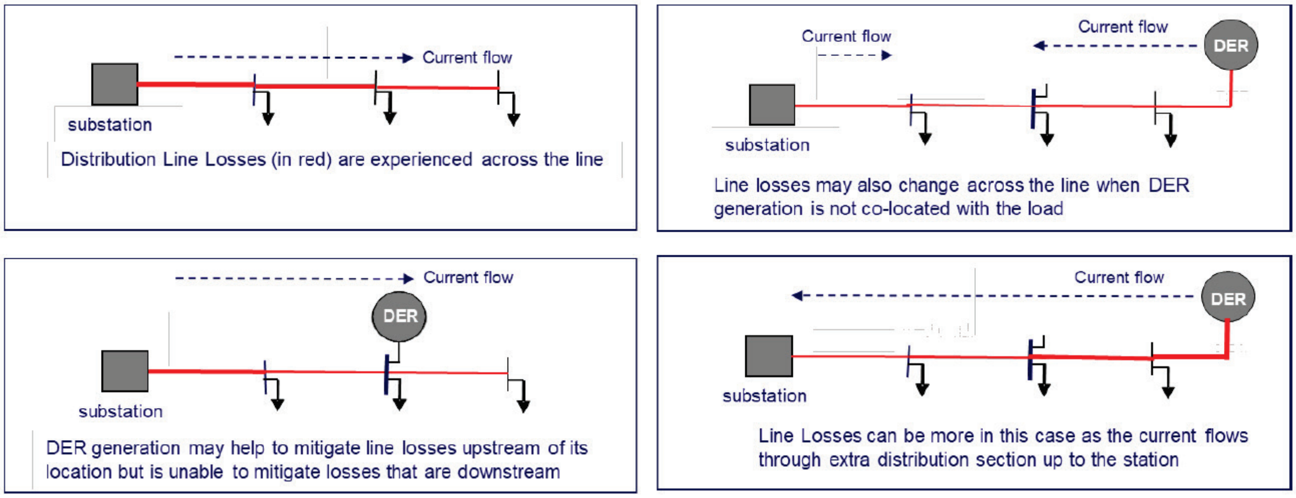


Figure 7-2. Line loss variation for varying DER locations – Commonwealth Edison[128]

Accounting for self-consumption

When assessing DER benefits, accurate accounting for customer self-consumption is critical to preventing double-counting. All else being equal, DER production that is self-consumed offsets local consumption that would otherwise be billed at full retail rates. To prevent double-counting, self-consumed energy can be removed from the resource profile or subtracted from the resulting value calculations. Self-consumption is highly efficient and generally desirable but must be accounted for when computing costs and benefits from a system perspective. Utilities can estimate self-consumption using customer PV system size and meter energy export data. In utility distribution planning filings, self-consumption should be addressed as part of the overall DER value determination process.

Customer understanding

To the extent that value of DER analysis is intended to inform DER compensation (either directly or via a third party), it is critical that customers understand how they will be compensated. Customers need to have sufficient information to ensure that they understand the project economics when determining whether to proceed with installing DER. Especially for DER value and compensation that varies by location and time, customers' ability to understand and respond to that information is part of developing programs and rates. While regulators typically approve programs and rates in separate tariff filings, distribution planning guidance for utilities can include providing information on design and implementation of value of DER programs and rates, including customer communications.

Investments with multiple benefit streams

DER value calculations have historically relied on avoided costs, especially for distribution capacity. While this is a useful approach for quantifying DER value, it is important to consider other values that may be provided by DER-based approaches, as well as traditional utility investments. When a distribution asset is replaced with a larger asset for capacity, the new asset is less prone to failure and

[128] ComEd, ComEd Refiled Grid Plan - Chapter 5: Hosting Capacity and Interconnection Investments, p 46, 2024

may have fewer maintenance and testing requirements as a result. Capturing the full extent of benefit streams is critical to a reasonable and holistic valuation framework, including calculation methods, in distribution system planning.

7.2 Data Outputs

While data inputs and methodologies for calculating DER value may be extensive, results are often simplistic, with a focus on dollar value equivalents for DERs providing specific grid services. Because DERs can impact all levels of the power system, transmission and bulk power system benefits may be analyzed alongside distribution value drivers to provide a more complete picture of DER value. The two most common formats for outputs from DER value processes are study reports and calculation tools.

Study reports generally document the input data, calculation methods, and resulting dollar equivalent values along with other jurisdiction-specific drivers. Table 7-6 illustrates resulting dollar values for different value streams included in these reports.

Table 7-6. DER avoided cost results for the District of Columbia (2020$/MWh)[129]

Impacts		Avg		
		2025	2035	2045
Energy		32	40	49
Generation Capacity		5	5	9
Transmission Capacity		3	3	3
Distribution Capacity, O&M, and Voltage	F1	1,258	279	238
	F2	136	245	254
	F3	109	224	193
	F4		0	
Distribution Losses		2	3	3
GHG	L	30	27	22
	M	70	59	47
	H	142	131	118
Public Health			8	
Other (Credit and Collections, Equity, Resilience)		34	34	35

Calculation tools provide a hands-on method for stakeholders to engage with and understand the value of DERs. Users can adjust inputs such as DER type, size, and location, and financial parameters to observe how inputs change the resulting dollar values. California's Avoided Cost Calculator[130] and New York's Solar Value Stack Calculator[131] (Figure 7-3) are examples of calculation tools. These tools are used to attribute long-run savings to DERs deployed across the system or in targeted locations, or both. For example, New York utilities use their annual marginal cost of service study to define two load reduction values for the Value Stack tariff:[132] one that is location-specific, and another that is systemwide. The Demand Reduction Value represents subtransmission and distribution costs that the utility avoids as a

[129] Kallay, J. et al., *A Value of Distributed Energy Resources Study for the District of Columbia: Framework, Impacts, Key Findings, and Roadmap*, 2023
[130] California Public Utilities Commission, DER Cost-Effectiveness. Avoided Cost Calculator (ACC), 2024
[131] New York State, Solar Program (NY-SUN), The Value Stack, 2024
[132] See https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources

result of DERs.[133] A higher Locational System Relief Value is available in utility-identified locations where DERs can address certain types of distribution investment needs. Compensation for this additional value targets highly constrained areas likely to require distribution system upgrades or other new investments in the absence of increased DER capacity contributions.

Value Stack Calculator v 3.1, for Projects Impacted by the 2019 Value Stack Order (Qualified after 7/26/2018)					
MONTHLY COMPENSATION FOR EXPORTS - SOLAR:					
	2024	*2024*	*2024*	*2024*	*2024*
	2024_1	*2024_2*	*2024_3*	*2024_4*	*2024_5*
	Jan-24	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**
Exports					
Solar generation immediately exported by solar system (kWh)	680,678	856,099	981,466	898,724	1,000,822
Value stack compensation from solar exports ($Nominal)					
Energy value	$ 63,444	$ 74,553	$ 52,898	$ 44,737	$ 57,819
Capacity value (36-month average Alternative 1 Rate (Jan 2021-Dec 2023) selected)	$ 13,325	$ 15,946	$ 7,421	$ 3,098	$ 13,784
Environmental value	$ 21,121	$ 26,565	$ 30,455	$ 27,887	$ 31,056
Demand reduction value	$ -	$ -	$ -	$ -	$ -
Locational system relief value	$ -	$ -	$ -	$ -	$ -
Community Credit	$ -	$ -	$ -	$ -	$ -
Total Value Stack compensation from solar generation immediately exported	$ 97,890	$ 117,064	$ 90,773	$ 75,722	$ 102,658
Average Value Stack compensation from solar - Per kWh exported ($Nominal/kWh)					
Energy value	$ 0.0932	$ 0.0871	$ 0.0539	$ 0.0498	$ 0.0578
Capacity value (36-month average Alternative 1 Rate (Jan 2021-Dec 2023) selected)	$ 0.0196	$ 0.0186	$ 0.0076	$ 0.0034	$ 0.0138
Environmental value	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310	$ 0.0310
Demand reduction value	$ -	$ -	$ -	$ -	$ -
Locational system relief value	$ -	$ -	$ -	$ -	$ -
Community Credit	$ -	$ -	$ -	$ -	$ -
Average Value Stack compensation, per kWh immediately exported	$ 0.1438	$ 0.1367	$ 0.0925	$ 0.0843	$ 0.1026
MONTHLY ON-SITE BILL REDUCTIONS FROM PROJECT:					
Retail rate taken from User Inputs row 123	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**
On-site consumption served by solar (kWh)	-	-	-	-	-
On-site parasitic load during hours with no solar generation (kWh)	-	-	-	-	-
Value of solar kWh consumed on site, at retail rate ($Nominal)	$ -	$ -	$ -	$ -	$ -

Figure 7-3. New York Solar Value Stack Calculator – Detailed outputs example

7.3 Best Practices

Best practices for sharing data on value of DERs include:

- Identify the types of DERs considered in value of DER analysis and explain the DER operational assumptions used.
- Identify specific distribution services considered in value of DER analysis and clearly document methodologies for quantifying the value of those services.
- To the extent practical, capture variations in DER value across the system due to differences in grid needs based on location.
- Accurately account for customer self-consumption to avoid double-counting benefits of behind-the-meter DER.

[133] In practice, some utilities quantify the costs of incremental transmission and distribution capacity instead of the demand reduction value.

8. Grid Needs Assessment

A *grid needs assessment* is an output of distribution system analysis that transparently identifies specific grid deficiencies over a set period (e.g., 10 years). Utilities leverage data from other distribution system analyses for the assessment, including load and DER forecasting and scenario analysis. The assessment includes a description of the deficiency, associated engineering characteristics, and timing of the need. Utilities prioritize grid needs identified and near-term actions.

The grid needs assessment informs the utility's distribution system investment strategy, including both traditional grid upgrades and pricing, programs, and procurements for non-wires alternatives (NWAs). The assessments also can support distribution system operations—for example, when the grid deficiency is projected to materialize before the utility can implement an infrastructure solution.

Utility data supporting the grid needs assessment allows regulators and stakeholders to understand the processes and analyses the utility used to identify investment needs, including robustness of approaches used. Utility data on identified grid needs, and their prioritization, is relevant to understanding capital project proposals presented for regulatory review. Utilities can report data and information related to the scope of the grid needs assessment, analytical approach, grid needs identification, and grid needs selection (Table 8-1).

Table 8-1. Grid needs assessment data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Scope	Objectives and regulatory compliance	Establishes the breadth and depth of the assessment and how it fits into the utility's distribution system planning strategy
Analytical approach	Methodology, limitations, and tools	Characterizes the approach implemented to identify grid needs
Grid needs identification	Asset characteristics, description of grid need, cost estimates, timing of grid need, and engineering characteristics	Identifies assets impacted by grid deficiencies
Grid needs selection	Grid needs prioritization and solutions	Selects grid needs for near-term investments and describes the approach that will be used to identify solutions

8.1 Data Inputs

8.1.1 Scope of the assessment

The grid needs assessment is shaped by the utility's strategy and applicable state requirements. Information on the scope of the assessment enables regulators and stakeholders to understand the breadth and depth of the analysis and how it fits into the utility's distribution planning activities. Utilities can provide information on their objectives and regulatory compliance.

Objectives establish the intended outcome the utility aims to achieve through the analysis. In addition to meeting overarching objectives such as maintaining grid reliability and resilience, specific aims for the assessment may include ensuring that all grid needs are characterized in detail and considered for NWA procurements and geotargeted programs when suitable. This information helps regulators and stakeholders understand how the assessment fits within the utility's strategy.

Regulatory compliance describes how the utility followed state requirements and commission guidance for implementing the grid needs assessment. This information simplifies regulatory oversight, including reviewing the adequacy of the approach. Compliance information also can provide regulators with valuable information on assessment challenges and inform future regulatory actions to improve assessment practices. For example, Pacific Gas & Electric's *2024 Distribution Grid Needs Assessment* report provides information on applicable commission decisions and regulatory requirements.[134]

8.1.2 Analytical approach

Grid needs assessments require a robust analytical approach supported by accurate system and asset data and engineering analysis. Regulators and stakeholders benefit from data and information to understand the approach followed, assess its suitability, and provide recommendations for improvement when appropriate. Utilities can provide data on their methodology, limitations, and tools. Utility data on the *methodology* can include information on the process designed to identify grid needs. For example, in its 2023 Integrated Grid Plan, Hawaiian Electric provides its grid needs modeling framework and describes the steps included in the process (Figure 8-1). The framework also provides the logic criteria applied across the analysis to establish the final portfolio of grid needs. Utilities also can report on assumptions used to support the analysis, as well as the time frame.

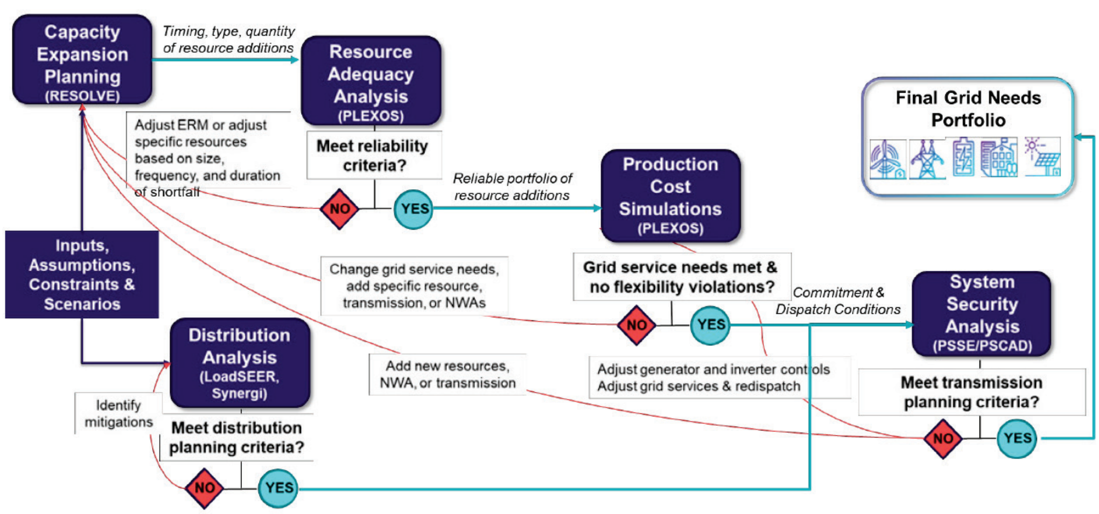


Figure 8-1. Grid needs modeling framework – Hawaiian Electric 2023 Integrated Grid Plan[135]

[134] PG&E, 2024 Distribution Grid Needs Assessment, 2024a
[135] Hawaiian Electric, 2023 Integrated Grid Plan, 2023

Utilities can report *limitations,* including a description of any shortcomings of the existing analytical approach or future considerations to improve existing processes. This may include gaps in asset engineering data, load and DER forecast uncertainty, and analytical tool limitations. The data inform regulators of challenges in identifying grid needs and can aid the interpretation of results by providing relevant context. For example, PacifiCorp's 2022 Distribution System Plan for Oregon provides a set of lessons learned through its grid needs assessment process. These include the need for granular data to understand the magnitude of grid needs, including the time of day, duration, and number of times a year the deficiency occurs, and the importance of allocating sufficient time for analysis.[136]

Utilities also can provide information on the *tools* deployed to support their analysis, such as commercial software or utility-developed tools. This information can improve transparency of the utility's analytical approach and enable regulators to assess tool capabilities and adequacy. For example, Pacific Gas & Electric (PG&E) describes the tools necessary to support its grid needs assessment and how the utility combines multiple tools to identify grid needs and automate its workflow. The utility uses LoadSEER,[137] a distribution system forecasting software for substations and feeders, to generate inputs for the analysis. In addition, the utility describes the various tools used to support planning automation, including CYME's Forecast Integration Tool,[138] which supports feeder analysis and can store data and support other departments engaged in distribution system planning.[139]

8.2 Data Outputs

8.2.1 Grid needs identification

Utilities can provide a range of data and information to describe identified grid needs, including asset characteristics and a description, cost estimates, timing, and engineering characteristics of the grid need.

Data on *asset characteristics* provides information to identify equipment impacted by a grid need. Utilities can report unique identifiers used to track the affected distribution system assets and their location.

Utilities can provide information *describing the grid deficiency* impacting the assets. This information enables regulators to understand drivers for near-term investments proposed and can inform future distribution system planning guidance to address emerging grid needs. For instance, a utility may find that most of its grid needs are related to limited distribution capacity, which could spur regulators to strengthen planning processes to deploy cost-effective DERs to defer, reduce, or mitigate grid upgrades.

136 PacifiCorp, Docket UM 2198, Distribution System Plan Part 2, 2022
137 LoadSEER is developed by Integral Analytics.
138 CYME is developed by Eaton.
139 PG&E, *2024 Distribution Grid Needs Assessment*, 2024a

In Nevada, NV Energy reports the results of its assessment categorizing grid needs due to thermal, reliability, or voltage constraints.[140]

Utility data on *cost estimates* gives regulators and stakeholders a reference point on what a traditional "wires" solution may cost to solve the grid need identified. This cost estimate can inform regulatory decisions regarding the utility's selection of cost-effective solutions to meet grid needs. For example, Hawaiian Electric organizes cost estimates for grid needs as those related to hosting capacity constraints (i.e., the ability of distribution system assets to accommodate DERs) and location-based constraints (i.e., the ability of distribution system assets to serve forecasted load growth). For each type of need, the utility provides data for a range of scenarios (Table 8-2).

Table 8-2. Grid needs cost estimates for O'ahu – Hawaiian Electric 2023 Integrated Grid Plan[141]

O'ahu hosting capacity grid needs, 2023-2030

Parameter (Nominal $)	Base DER Forecast	High DER Forecast	Low DER Forecast
Number of grid needs	6	16	5
Cost summary (wires solutions)	$792,000	$3,895,000	$648,000

O'ahu location-based grid needs, 2023-2030

Parameter (Nominal $)	Scenario 1 (Base)	Scenario 2 (High Load)	Scenario 3 (Low Load)	Scenario 4 (Faster Technology Adoption)
Number of grid needs	22	41	19	29
Cost summary (wires solutions)	$95,724,000	$152,426,000	$77,900,000	$165,934,000

Utilities can provide data on the *timing of the grid need* to inform regulators and stakeholders of when an asset will be impacted to inform planning and investment decisions. In addition to stating the year when the grid need is expected, the utility can indicate the season (or month) in which the grid need is expected to materialize, and the start and end times the deficiency occurs to inform the selection of suitable solutions.

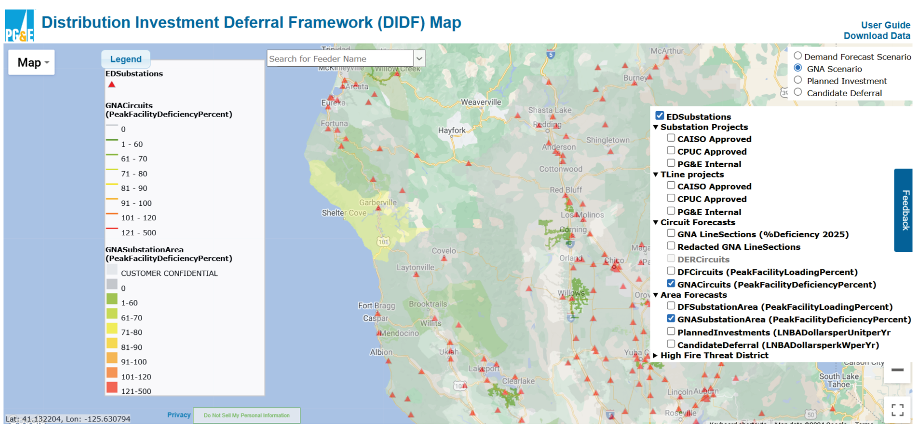
Utilities can describe the *engineering characteristics of the grid need identified*, including the operational condition when the grid need occurs—during normal operating conditions or when the system faces contingencies. Utilities also can provide data on the expected duration of the grid need, including the number of hours per year, the number of days per year when the asset experiences loading greater than its limit, and the number of hours on the forecasted peak day. These data allow regulators and stakeholders to understand the severity of the grid needs identified and can provide relevant information to support justifications of utility investment proposals.

140 NV Energy, Docket 23-09002, 2023 Distributed Resources Plan, 2023.
141 Hawaiian Electric, *2023 Integrated Grid Plan*, 2023

Utilities typically provide data on grid needs identification through regulatory filings in report format. Utilities can complement these filings with web portals to increase access to data (see text box).

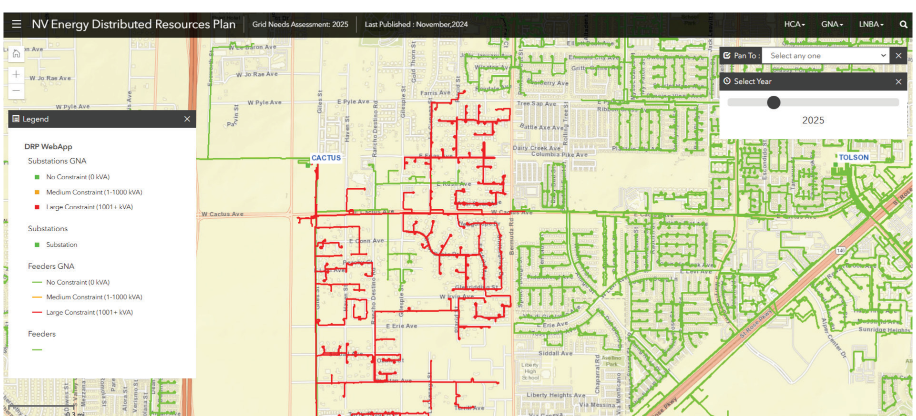
Online Portals for Data Access and Maps for Grid Needs

Utilities can use online portals to increase data access and transparency for grid need assessments. Online portals can provide mapping tools and enable downloading of granular data characterizing asset grid needs and provide mapping tools. Online portals are valuable for developers to identify areas where DERs may be a suitable solution to address grid needs. For example, PG&E's web portal provides data downloads and maps. The map allows users to toggle through various options to visualize grid deficiencies for feeders and substation areas. Users can select assets on the map to access more data, including the cause of the grid need, the date when the grid solution is needed, and the value of the grid need in MW and as a percentage of the asset capacity.[142]



Source: PG&E, [Grid Needs Assessment Map,](#) 2024

Similarly, NV Energy in Nevada has a web portal with mapping and data download capabilities.[143]



Source: NV Energy, [Distributed Resources Plan Portal,](#) 2024

142 PG&E, [Distribution Investment Deferral Framework (DIDF) Map User Guide](#), 2022

143 NV Energy, [Docket 24-05041, Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 Integrated Resource Plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027](#), 2024

8.2.2 Grid needs selection

The utility concludes its assessment by prioritizing grid needs for near-term investments. The distribution system plan can report on the utility's prioritization criteria and approach.

Utility information on *grid needs prioritization* provides details on how the utility selects the grid needs that require near-term action. This can include information on the methodology applied to rank grid needs. The information provides insights into factors driving utility investment priorities. Portland General Electric's 2022 Distribution System Plan included data on the utility's ranking methodology across five levels, with level 5 as the highest priority:[144]

- Level 5 – safety and customer commitment
- Level 4 – impacts to other facilities
- Level 3 – heavy loading telemetry, and substation risk
- Level 2 – feeder risk, load growth, and redundancy
- Level 1 – system utilization and DG readiness

The utility developed prioritization criteria and scores for each level to rank grid needs (Table 8-3).

Table 8-3. Grid needs prioritization criteria – Portland General Electric 2022 Distribution System Plan[145]

Level	Title	Max possible score	Multiplier	Max total	Peak importance
Level 5	Addresses Safety Concern? Yes = 15, No = 0	15	5	75	21.8%
	Must Do for Customer Commitment? Yes = 15, No = 0	15	5	75	21.8%
Level 4	Compliance Driver or Mitigates Transmission/ Sub-Transmission Constraint? 115 kV+ = 10, 57 kV = 5, No = 0	10	4	40	11.6%
	Precursor to mitigating other grid needs? Two or More = 10, One = 5, No = 0	10	4	40	11.6%
	Frees up or mitigates mobile/ temporary equipment or configuration? Yes = 5, No = 0	5	4	20	5.8%
Level 3	Feeder % Loading of Seasonal Limit (N-0) >100% = 4, 90%-99% = 3, 80%-89% = 2, 67%-79% = 1, <67% = 0	4	3	12	3.5%
	Transformer % Loading of LBNR (N-0) >100% = 4, 90%-99% = 3, 80%-89% = 2, <80% = 0	4	3	12	3.5%
	Existing Total Risk (Substation) Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0	4	3	12	3.5%
	Existing CMI Impact (Substation) Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0	4	3	12	3.5%
	Substation SCADA Adds New = 3, Replace Obsolete = 1, No or New Sub = 0	3	3	9	2.6%

LBNR – Loading Beyond Nameplate Ratings; CMI – Customer Minutes Interrupted; SCADA – Supervisory Control and Data Acquisition

[144] PGE, Docket UM 2197, Distribution System Plan Part 2, 2022a

[145] This figure includes only levels 3 to 5 for illustration. The full set of criteria can be found in Portland General Electric, Docket UM 2197, Distribution System Plan Part 2, 2022a, p 190.

Information on the utility's *approach to identifying grid needs solutions* describes processes suitable to address selected grid needs. Some grid needs may be suitable candidates for NWA procurements or geotargeted programs; others may require a grid upgrade. Utilities also can report the timeline for initiating the solution implementation process and the date by which a solution must be in place.

8.3 Best Practices

Best practices for sharing data on grid needs assessment include:

- Provide data on analytical steps followed to identify grid needs. This can include information on utility processes, including dependencies with other distribution planning activities such as load and DER forecasts and scenario analysis.
- Disclose commercial and utility-developed tools used and their role in the analysis. This can include a description of each tool, its capabilities, and how they fit into the utility grid needs assessment workflow. Utilities also can report any limitations and challenges experienced with available tools to inform future distribution planning efforts and enable regulators to understand existing hurdles, which may inform future planning guidance. Utilities may be able to use open-source tools, make their own tools available to stakeholders, or facilitate licenses for stakeholders for proprietary tools used.
- Share comprehensive grid deficiency data to enable identification of cost-effective solutions. This can include granular data to characterize the distribution system asset, the magnitude of the deficiency, and its expected duration.
- Leverage data portals to facilitate access by regulators, developers, and other stakeholders. This can include launching a web portal with data download capabilities and interactive maps to complement traditional regulatory filings.

9. Cost-Effectiveness Evaluation for Investments[146]

Cost-effectiveness evaluation assesses the benefits and costs of grid investments and qualitative factors to achieve established planning objectives to determine an optimal course of action. Utility data and analysis on cost-effectiveness are relevant for regulators and stakeholders to understand the economic impact of distribution system investments. Utility data on cost-effectiveness can support regulators in assessing and determining which investments may be appropriate for approval and deployment—and which investments may need to be assessed further prior to making a decision, postponed and considered in future proceedings, or rejected.

Table 9-1 summarizes categories and types of data that utilities can report related to cost-effectiveness evaluation and how the data impact distribution system planning.

Table 9-1. Cost-effectiveness data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Solution justification data	Description of selected investments and other expenditures, expected outcomes, investment drivers (compliance with standards, regulations, or policies or enabling other new capabilities), and engineering analyses	Identifies alternatives considered, selected solutions, and rationale
Cost-effectiveness analysis screening	Scope of analysis (individual solution or integrated set of technologies), screening method, estimates of benefits and costs, uncertainty analyses, and ex-post results from prior distribution plans	Determines approach (lowest reasonable cost or benefit-cost analysis) the utility uses for initial economic evaluation of proposed expenditures based on investment drivers
Portfolio development	Scoring and ranking methods (e.g., multi-objective decision analysis, value-spend efficiency) and results, planned portfolio of expenditures	Prioritizes screened expenditures based on cost and potential contribution toward achieving planning objectives to create value for utility customers and society

A well-designed integrated distribution system planning (IDSP) process provides a framework for translating multiple policy objectives into holistic infrastructure investment strategies and related cost-effectiveness evaluation. That includes establishing metrics for each objective and prioritizing among them. The set of objectives, metrics, and priorities facilitates effective assessment of grid technology options, physical infrastructure alternatives, and operational expenditures (Figure 9-1). Importantly, customer affordability is the global objective that sets the financial constraint for cost-effectively optimizing a portfolio of distribution expenditures to achieve other planning objectives. A best practice is identifying each expenditure and linking it to one or more distribution modernization objectives and metrics. Many distribution modernization expenditures address more than one objective.

[146] Paul De Martini, Newport Consulting, is a significant contributor to this section of the report.

	Customer Affordability					
	Reduce Wildfire Risk	**Increase Grid Capacity**	**Improve Asset Health**	**Improve Reliability**	**Promote Equity**	**Increase Resilience**
Description	Reducing wildfire risk and preventative outage impacts to customers and communities	Expand grid capacity to remedy overloading and facilitate electrification	Address underlying asset health (e.g., age) issues that lead to failure	Reducing frequency and duration of outages	Ensure benefits of the grid are fairly distributed across all communities	Aim to build a more resilient to anticipated impacts of climate change and other natural disasters
Metrics	Wildfire Multi-factor Risk Score PSPS related CMI	Number and MW of substations & feeders overloaded	Risk-weighted share of unhealthy assets Percentage of assets past expected life and at risk of failure	SAIDI & SAIFI w/o Major Events CEMI	Percentage of expenditure in disadvantaged and vulnerable communities	Percentage of spend in areas at risk of climate and other natural hazards (e.g., earthquakes) Number of identified grid vulnerabilities addressed

Source: P. De Martini

Figure 9-1. Example utility grid planning objectives and metrics

Cost-Effectiveness Methods

There are two fundamental approaches for evaluating distribution investments:[147]

1. **Lowest reasonable cost:**[148] LRC (or "best fit, least cost") is a quantitatively focused method based on engineering or technology architectural analysis, or both, to discern the need for and cost of a solution based on compliance with statutory requirements and explicit and implicit regulatory requirements identified in the distribution planning process. LRC answers the question: *What is the lowest reasonable cost to meet a safety, reliability, or other statutory or regulatory requirement?* The approach requires clear alignment and supporting engineering rationale for meeting statutory and regulatory requirements. LRC also is applied to individual expenditures with interdependent relationships in which the full value is only realized when the interdependent components are all deployed.

2. **Benefit-cost analysis:** BCA is a quantitatively focused method based on monetizing the benefits and costs of distribution modernization expenditures over a defined time period. It is best used when the dollar value of the benefits of a distribution modernization solution is discrete and assignable, quantitatively measurable, and does not materially change with increasing or decreasing usage.[149] BCA answers the question: *Will a specific or interrelated group of grid expenditures enhance welfare (i.e., benefits > costs) for all or a subset of customers?*

[147] De Martini, Ball, and Schwartz, *Economic Evaluation of Distribution Grid Modernization Expenditures: A Guide for Utility Regulators,* forthcoming.

[148] Utilities use a Lowest Reasonable Cost approach to justify reasonableness for many types of distribution expenditures, both capital investments and operating expenses, in general rate cases. De Martini et al. (2024) describes a more systematic approach to ensure transparency and alignment with planning objectives and priorities than methods often used for distribution-related expenditures in rate cases.

[149] DOE, Modern Distribution Grid: Strategy & Implementation Planning Guidebook. Vol. IV, 2020

The specific cost-effectiveness evaluation method to apply depends on state requirements and grid capabilities needed to meet state goals and objectives. Regardless of the method employed, utilities can share the underlying data related to grid needs, alignment with planning objectives, alternatives considered, and cost and benefit estimates. Given uncertainty, the level of detail and precision will be different for identified future expenditures compared to near-term expenditures. The utility can articulate the differences between longer-term and near-term cost-effectiveness calculations, including discussing the estimation methods employed.

9.1 Data Inputs

9.1.1 Grid need and solution justification data

After identifying needed investments, the utility can provide data to characterize them, and alternatives considered, laying out considerations for cost-effectiveness evaluation. Utility data for investment *characterization* includes a description of the selected capital investments and operating expenses included in the assessment and expected outcomes. Utilities also can provide information on the specific drivers and engineering analyses for the selected expenditures. Information characterizing selected expenditures enables regulators to assess how distribution system planning objectives translate into discrete grid needs and specific solutions. This "line of sight" between planning objectives and specific proposed expenditures is essential to a transparent IDSP process.

Information related to the utility's *cost-effectiveness considerations* includes the evaluation methodology applicable to the investment selected and a description of why the selected methodology is suitable for the investment under consideration. Information on the selected methodology helps regulators and stakeholders understand the utility's rationale and assess whether it matches regulatory priorities for cost-effective distribution system investments. Understanding which driver(s) informed a utility's choice of expenditures is critical to determining which cost-effectiveness methodology is appropriate for evaluating an expenditure (Figure 9-2).

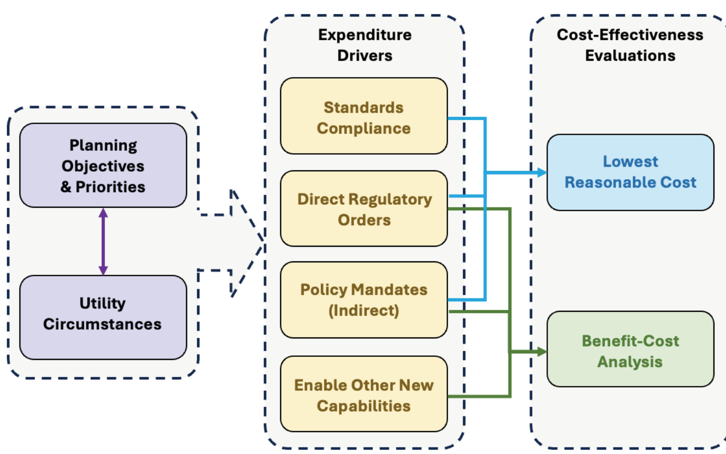


Figure 9-2. Drivers and cost-effectiveness evaluation methods[150]

[150] De Martini, P., J. Ball, and L. Schwartz. 2025

Figure 9-2 illustrates the following choices to assess the cost-effectiveness of various grid solutions based on the investment driver:

- **Standards compliance:** Solutions to comply with safety, power quality, and reliability standards are addressed using LRC.
- **Direct regulatory order:** Solutions in response to a regulatory order may be addressed using LRC or require a BCA, depending on whether the decision and order included a finding that the required capability was in the interest of the public and utility customers. If so, then the LRC method may apply.
- **Policy mandates:** For instance, legislation requiring commercial fleet and light-duty vehicle sales (by a certain date) considers societal value, and compliance with the statute may require new enabling grid capabilities. However, not all policy mandates identify the value to utility customers. In these cases, a BCA is used to determine the cost-effectiveness of solutions.
- **Other new capabilities:** Solutions identified by the utility to improve operations, but that are not driven by compliance, regulatory, or policy mandates, are evaluated using BCA.

States may have specific requirements indicating the methodology applicable for specific investment categories. Regardless of the cost-effectiveness analysis method, a clear narrative summary of a utility's decision is needed, based on planning objectives and priorities, grid needs, expenditure attributes, metrics, and relevant financial analysis.

9.2 Data Outputs

9.2.1 Benefit-cost analysis data

The utility can provide data and information on the scope of the analysis, cost-effectiveness methodology, cost and benefit estimation, uncertainty analyses, and any ex-post results from prior distribution system plans.

Utility data on the *scope of the analysis* can include a description of the specific grid solution or integrated set of IT/OT technologies analyzed.

Utility data and information on the *cost-effectiveness methodology* can include the description and rationale for its use in the analysis. For example, in its 2024 Multi-Year Integrated Grid Plan, Ameren Illinois provided regulators with information on its cost-effectiveness framework, outlining the utility's approach to evaluating different types of investments.[151] The framework describes the cost-effectiveness analytical approach for different types of investment drivers and provides examples of investments covered under different approaches.

Information on *estimation methods* to determine implementation and operational costs, and any

[151] Ameren Illinois, Ameren Illinois' Refiled Multi-Year Integrated Grid Plan, 2024

benefits associated with proposed expenditures, includes a discussion of method(s) used for conceptual estimates for future expenditures and benefits. Near-term expenditure costs can be supported by detailed information, including vendor price proposals. Likewise, near-term benefits may have greater detail based on recent information for benefit categories.

Conceptual cost estimates provide a basis to evaluate feasibility in long-term strategic planning included in distribution system plans. These estimates do not reflect a detailed design and business impact assessment or technology procurements. Conceptual cost estimates are developed through one or more of the following three cost engineering methods employed across industry sectors and government agencies:[152]

- **Historical estimating** uses historical data from similar projects as a basis for the cost estimate. The estimate can be adjusted for known differences between the projects. In the electric industry, this type of estimate is effective if there are significant historical cost data on electric infrastructure to draw upon. This estimating technique does not apply to new technologies that have no historical implementation information.
- **Parametric estimating** uses key parameters such as unit cost and quantity to calculate an estimate for deployment of devices or systems. For example, unit costs may be derived from historical average unit costs and industry cost guides (e.g., RSMeans Estimating Guidebook). AEP's Indiana-Michigan Power Company's 2019-2023 distribution plan[153] provides an example (Table 9-2). The total cost for each technology (e.g., "Station SCADA"), derived from an average unit cost, is multiplied by the quantity to develop a conceptual estimate.

[152] DOE, Modern Distribution Grid, Vol. IV, 2020
[153] Indiana Michigan Power Company, *Michigan Five-Year Distribution Plan (2019-2023),* 2019, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000004Q5rJAAS

Table 9-2. Parametric estimating example: Indiana Michigan Power Company's 2019-2023 Grid Modernization Investment Plan

Distribution Automation 2022				
Lakeside / New Buffalo	Union Pier / Bison	Install new automatic transfer scheme	1	Each
Main St / Riverside	Sears / Paw Paw Ave	Install new automatic transfer scheme	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,255,608		

Station SCADA 2020				
Station	Station	Description	Units	UOM
Stevensville	Stevensville	Install station SCADA	1	Each
Three Oaks	Three Oaks	Install station SCADA	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,393,443		

Station SCADA 2021				
Station	Station	Description	Units	UOM
Buchanan Hydro	Buchanan Hydro	Install station SCADA	1	Each
		Total	1	
	Estimated O&M			
	Estimated Capital	$1,175,727		

- **Equipment-factored estimating** typically takes the indicative/list price of the technology and multiplies it by installation and/or integration factors to determine conceptual costs. The installation factor, or total installed cost, includes technology vendor and consulting costs, associated internal project labor costs, additional costs needed for technology installation, and ongoing costs for operational and maintenance services.

Conceptual estimates developed using these top-down methods may include range estimates to frame the related *uncertainty*, as Table 9-3 shows.

Table 9-3. SCE grid modernization conceptual estimates

Category	Specific Investments		2015	2016	2017	2018 GRC (2018-2020)
Distribution Automation	#1	Automated Switches w/ Enhanced Telemetry	$500K - $1M	$3 - $5M	$35 - $60M	$185 - $320M
	#2	Remote Fault Indicators				
Substation Automation	#3	Substation Automation	$1.3 - $1.6M	$5 - $10M	$25 - $45M	$185 - $320M
	#4	Modern Protection Relays				
Communication Systems	#5	Field Area Network	$100 - $200K	$2 - $5M	$5 - $10M	$270 - $470M
	#6	Fiber Optic Network				
Technology Platforms and Applications	#7	Grid Analytics Platform	$10 - $13M	$65 - $100M	$55 - $85M	$215 - $375M
	#8	Grid Analytics Applications				
	#9	Long-Term Planning Tool Set				
	#10	Distribution Circuit Modeling Tool				
	#11	Generation Interconnection Application Processing Tool				
	#12	DRP Data Sharing Portal				
	#13	Grid and DER Management System				
	#14	Systems Architecture & Cybersecurity				
	#15	Distribution Volt/VAR Optimization				

Source: Southern California Edison

Conceptual estimates are not as detailed as values included in utility requests for cost recovery. However, these estimates can be useful to assess the magnitude of revenue requirements and associated rate impacts to consider customer affordability. Utilities in several states have incorporated conceptual estimates in distribution system plans to facilitate discussion about grid needs and affordability with regulators, utility customers, and other stakeholders.

Developing a detailed cost estimate ("engineering estimate") starts with detailed engineering design, related technologies, implementation plan, and vendor pricing. Engineering estimates involve estimating the cost for each major activity within the distribution system implementation plan. Engineering estimates for technologies and equipment usually are based on competitive vendor procurements or negotiated prices, or both. Remaining cost elements (such as various overhead charges) may be factored from direct labor and material costs.

Cost estimate summaries are typically provided in rate case filings, with detailed cost estimate analyses in work papers. Companion work papers may include information that is considered confidential vendor or service provider information. Access may be limited to regulatory staff and other parties in a regulatory proceeding under a nondisclosure agreement.

Utilities also can provide data related to *financial analysis*, such as cost escalation factors, discount rates, and the lifetime of the investments. It is important for regulators and stakeholders to understand the inputs and assumptions of the analysis. That may include describing how baseline data are generated for the analysis, as well as how *uncertainty* in selected inputs may affect cost-effectiveness analyses. Estimates often include contingencies based on these uncertainties to mitigate potential project risks. The utility can identify and discuss any contingencies incorporated into the analysis.

Sensitivity analysis can help utilities understand how variations in selected inputs may affect cost-effectiveness. Utilities can provide regulators and stakeholders with data and information on sensitivities included in the cost-effectiveness analysis.

Utilities use *ex-post cost and benefit data* to update cost and benefit assumptions and estimation factors as well as uncertainty analyses. Utilities can provide information on ex-post cost-effectiveness results from prior planning cycles and how they incorporated such data into current cost-effectiveness analyses.

9.2.2 Multi-objective prioritization

IDSP cost-effectiveness includes a determination of an optimal portfolio of expenditures in a specific time period[154] that provides tangible value to utility customers and society. Transparency in the methodology used is essential to the distribution system planning process. An effective multi-objective decision analysis (MODA)[155] supports a comprehensive, auditable, and robust assessment process that prioritizes expenditures aligned with established objectives and priorities. Utilities increasingly use MODA to prioritize distribution, given practical limits to utility spending due to customer affordability and utility financial and resource constraints, and regulators increasingly require utilities to conduct such analysis.

Since distribution planning typically addresses more than one objective, the utility identifies which solutions materially address the most objectives (or the highest priority objectives) for a given net cost. The MODA process assesses each proposed expenditure—whether first evaluated by Least Reasonable Cost or Benefit-Cost Analysis methods—quantitatively, qualitatively, or both against each objective and respective metric.[156] The utility defines each objective in quantitative terms (engineering or monetary metrics) or qualitative terms (e.g., safety attributes). The objective's priority ranking typically is reflected in a weighting factor applied to the total numerical score based on a proposed solution's contribution to addressing each objective (Figure 9-3). Using the resulting final score for each solution and its cost, the utility ranks each expenditure from highest to lowest score. Customer affordability is the global objective that sets the financial constraint for optimizing expenditures to achieve the other planning objectives.

Utilities can describe the prioritization methodology employed to determine the proposed portfolio of distribution expenditures, as well as the rationale for the scoring schema used to assess each expenditure's contribution toward achieving one or more objectives. For example, Portland General

[154] Cost recovery proceedings consider a single test year (or each rate year in the case of a multi-year rate plan). However, distribution planning usually identifies future needs and potential solutions across longer time frames (e.g., 10 years).

[155] Several industries and governments use MODA — for example, state highway and transportation agencies. See [How to Implement a Multi-Objective Decision Analysis (MODA) Approach.]

[156] For example, DTE has used a global prioritization model for several years. Other utilities have used weighted scores such as a Kepner-Tregoe framework. To aid in decision-making, utilities can convert non-monetary objectives to monetary values. See Baker et al. 2001 for an explanation of which types of projects each prioritization method is suited for and pros and cons.

Electric's (PGE) 2022 Distribution System Plan describes its MODA process (Figure 9-5). The scores are based on metrics developed using stakeholder input, statistical analysis, and heuristic adoption models. Each objective has an associated weight based on its priority, with the result that some objectives have a greater influence on the final project ranking.

Figure 9-3. Multi-objective prioritization for PGE's 2022 Distribution System Plan

9.3 Best Practices

Best practices for sharing data on cost-effectiveness evaluation include:

- Provide data to characterize distribution system expenditures evaluated for cost-effectiveness. That can include data on the specific distribution capital investments and operating expenses included in the assessment and information on how the expenditures address the identified grid needs.
- Ensure a transparent "line of sight" between each proposed distribution expenditure and its contribution to achieving one or more distribution planning objectives and requirements.
- Ensure that utility cost-effectiveness considerations align with distribution system planning objectives and criteria. The utility can provide detailed information on the cost-effectiveness methodology used and the rationale for selecting the approach. That can include assessment inputs, data sources, and information on any uncertainties affecting the analysis and mitigating actions.
- Provide a description and rationale of the cost and benefit estimation methodologies used for long-term and near-term cost-effectiveness determination.
- Provide information on the distribution expenditure prioritization method used, including details on how the utility incorporated planning objectives, the scoring approach and other factors employed, and the prioritization results.

10. Distribution System Investment Strategy and Implementation

The investment strategy is a utility's plan to achieve the objectives established for its distribution system planning process. The strategy addresses four interconnected dimensions:

1. **Asset management** includes traditional physical infrastructure, such as poles, wires, and transformers.
2. **Reliability and resilience** investments include physical upgrades, advanced technologies, and microgrids.
3. **Capacity expansion** includes physical upgrades and non-wires solutions, such as customer load flexibility and DER services.
4. **Advanced grid technology** includes solutions to advance monitor and control capabilities, including distribution automation. It also may include network and data management, planning and operational analytics, and technologies to enable DERs.

The investment strategy and implementation plan provides the utility's roadmap for meeting multiple DSP objectives in an affordable way over the planning horizon. The strategy and plan add transparency to the process by demonstrating how the utility translates planning objectives into expenditure decisions and provide context for the relationship between long-term goals and near-term needs. That supports regulatory review and stakeholder engagement with respect to how expenditures proposed for cost recovery in the short term, such as in a rate case, relate to future expenditure needs.

To prepare and implement the investment strategy, the utility relies on engineering, economic, and other technical data and analyses performed for the planning process. Sharing the information tells regulators and stakeholders how the utility identifies long-term investment needs and near-term investment proposals. Table 10-1 summarizes the investment strategy data and its impact on planning.

Table 10-1. Distribution system investment strategy and implementation data and impact on planning

Data category	Type of data reported	Impact on planning
Strategy development	Vision, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and strategic roadmap	Characterizes the long-term evolution of the distribution system and enables regulators to assess alignment with state policy goals and objectives, as well as planning requirements
Strategy implementation	Progress to date, future implementation, investments planned, costs and financing, and risks and mitigation	Connects long-term strategic plans with near-term actions, allowing regulators to understand progress and assess the adequacy of proposed investments in relation to the utility's long-term strategy

10.1 Data Inputs

10.1.1 Strategy development

Utility data related to strategy development provides insights into the utility's long-term plan for the evolution of its distribution system. Information the utility can provide includes a vision statement, objectives, strategy and investment drivers, capabilities and functionalities, grid architecture, and a strategic roadmap.

The utility's *vision* establishes its long-term ambition for the distribution system over a defined time frame. For example, California,[157] Colorado,[158] and Minnesota[159] utilities provide data on their vision for the distribution system in the next 10 years. In its 2021 General Rate Case, Southern California Edison (SCE) provided information on its 10-year vision for grid modernization to support increasing system complexity, customer empowerment to contribute to grid operations, and distribution markets to maximize the value of DERs (Figure 10-1).[160] Regulators can use this information to assess the utility's proposed investments and determine if they adequately advance the utility's vision, as well as state policy goals and objectives.

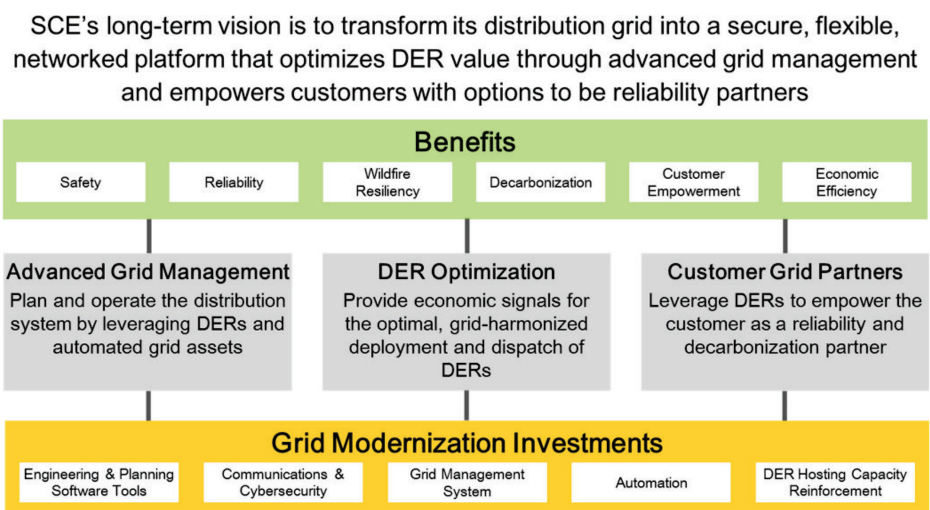


Figure 10-1. SCE's 10-year grid modernization vision[161]

The utility's *objectives* specify the outcomes the utility plans to achieve by implementing the distribution system strategy. For example, Xcel Energy in Colorado established the following objectives for its 2022 distribution system plan:[162]

- Implementing advanced forecasting and planning tools

[157] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021
[158] Xcel Energy, Proceeding 22A-0189E, Distribution System Plan, 2022.
[159] Xcel Energy, Docket No. E002/M-23-452, Distribution System Plan, Appendix B1: Grid Modernization, 2023b
[160] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021
[161] SCE, 2021 General Rate Case, Grid Modernization Plan, 2021 at 6
[162] Xcel Energy, Proceeding 22A-0189E, Distribution System Plan, 2022, p 11.

- Improving asset health and reliability
- Emphasizing resiliency
- Enhancing DER monitoring and control capabilities
- Evolving demand-side management and DER offerings to meet distribution system needs
- Harnessing stakeholder input
- Enabling interconnection of DER

Utilities can provide information to regulators and stakeholders on market, policy and regulatory, and technology drivers to support a better understanding of proposed investments:

- *Market-related drivers* may include technology adoption, customer behavior, and any expected implications for system operations that may need to be addressed through specific investments.
- *Policy and regulatory-related drivers* may include information on new state or federal laws or commission rules impacting the distribution system.
- *Technology drivers* may include information on advancements in modern grid technologies and expected impacts on grid operations and system functionalities. For example, Eversource's Electric-Sector Modernization Plan for its Massachusetts service area included data on EV contributions to system peak demand over time by sub-region (Figure 10-2).

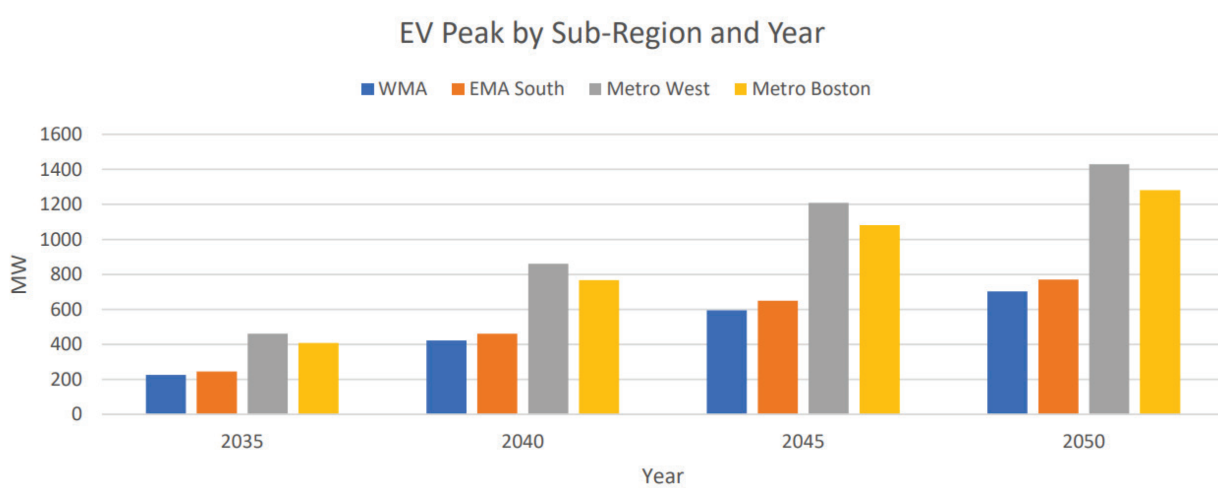


Figure 10-2. Eversource data on EV contribution to peak demand[163]

Notes: WMA: Western Massachusetts; EMA South: Eastern Massachusetts South

Utilities can provide data on the specific *capabilities and functionalities* enabled by the distribution system investments included in their strategy. A *capability* is the ability to execute a specific course of action, which may result from a combination of processes and technologies. An example of a distribution system capability can be to provide customers with access to their energy usage data. Capabilities inform what functions are needed. A *function* defines a business process, behavior, or operational result of a process. Planning identifies required changes to existing functions as well as new functions needed. Identifying functions within the context of needed capabilities to meet objectives is a

[163] Eversource Energy, *Electric Sector Modernization Plan*, 2024, p 509.

key reference point for strategic planning. Multiple functions can be combined to enable a capability. An example of distribution system functionality is deploying remote meter-reading, which would support access to energy usage data.[164] Rhode Island Energy included data on its capabilities and associated functionalities in its Grid Modernization Plan (Table 10-2).

Table 10-2. Rhode Island Energy grid modernization capabilities and functionalities[165]

Grid Modernization Capability	Grid Modernization Functionality
Customer Enablement	Advanced Metering (Customer Information, Advanced Pricing, Remote Metering) Distribution System Information Sharing
Monitoring & Control	Observability (Monitoring & Sensing) Distribution grid control (i.e., voltage control and fault management for compliance, flow control and state estimation) DER Management
Optimization	Voltage Control for Optimization Reliability Management DER Management
Data Acquisition	Operational Information Management Cyber Security Operational Telecommunications
System Modeling & Analytics	Distribution System Representation (Network Models) Grid Optimization

Utilities also can provide information on their *grid architecture* and how such considerations support the distribution system investment strategy, encompassing both the physical grid components and corresponding communication, control, and software systems. Grid architecture structures the planning and design of electric systems. It establishes the boundaries of what the grid can and cannot do and is an important component to support investment decisions.[166] Utilities can provide information on grid architecture by describing coordination, scalability, layering, and buffering considerations.

- *Coordination* is the process that causes or enables a set of decentralized elements to cooperate to solve a common problem.
- *Scalability* is the ability of a system to accommodate an expanding number of endpoints or participants without having to undertake major rework.
- *Layering* is applying fundamental or commonly needed capabilities and services to a variable set of uses or applications through well-defined interoperable interfaces (leading to the concept of a platform).
- *Buffering* is the ability to make the system resilient to a variety of disturbances.

Utility data on grid architecture may answer the following questions (Table 10-3).

[164] DOE, Modern Distribution Grid Strategy and Implementation Planning Guidebook Volume IV, 2020
[165] Rhode Island Energy, Grid Modernization Plan, 2022, p 73.
[166] DOE, *Modern Distribution Grid Strategy and Implementation Planning Guidebook Volume IV*, 2020

Table 10-3. Grid architecture questions that can be answered with utility data[167]

Coordination	How will we coordinate utility and non-utility assets? How will we address the information sharing requirements among participants?
Scalability	How do we enable optimal performance locally and systemwide? How do we minimize the number of communication interfaces (cyber-intrusion)?
Layering	How do we build out the fundamental components of the system to support new applications and convergence with other infrastructures?
Buffering	How do we address resilience and system flexibility requirements (e.g., what is the role of storage)?

In addition, utilities can provide information on their *strategic roadmap,* identifying current and future distribution system projects and initiatives and how they support the utility's strategy. The roadmap includes sequencing and relationships between projects and initiatives and indicates their status—completed, in progress, or planned for future implementation. For example, Figure 10-3 is the roadmap that Consolidated Edison filed with its 2023 Distribution System Implementation Plan.[168] The Gantt chart organizes projects and initiatives by theme, such as Advanced Metering and Grid Automation and Management, provides an overview of activities over time, and identifies milestones linking specific activities to regulatory proceedings, such as rate cases or distribution system implementation planning dockets.

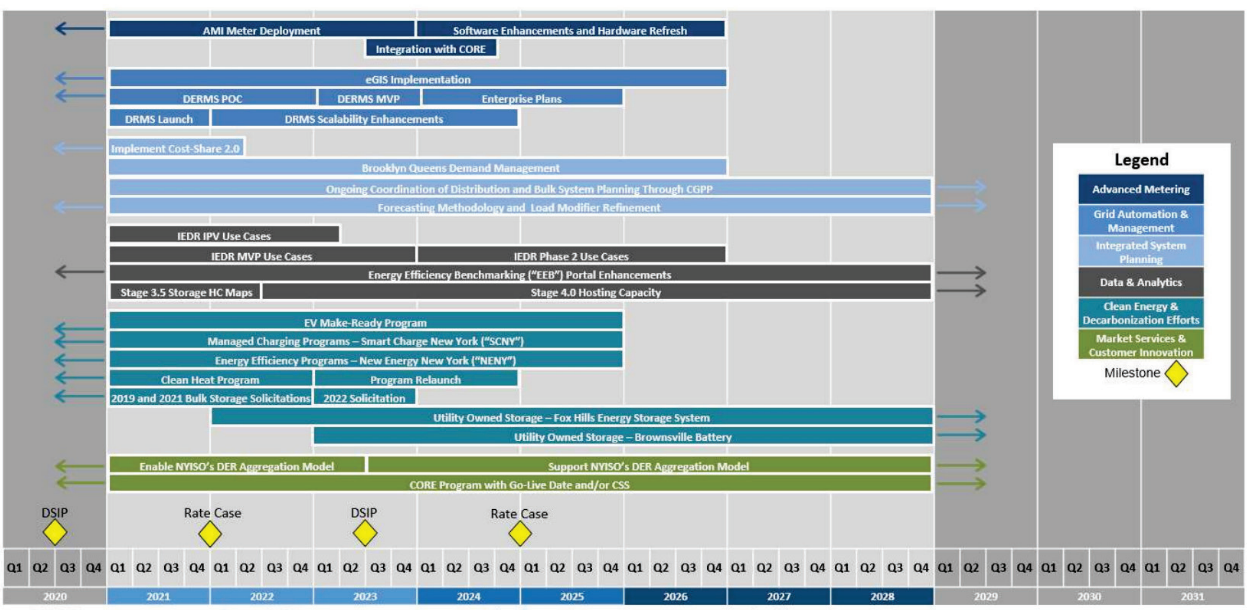


Figure 10-3. Consolidated Edison strategic roadmap[169]

[167] LBNL, Interactive Decision Framework for Integrated Distribution System Planning, Grid Architecture Considerations, 2024

[168] Consolidated Edison, Distribution System Implementation Plan, 2023, p 14.

[169] Consolidated Edison, Distribution System Implementation Plan, 2023, p 14.

10.2 Data Outputs

10.2.1 Strategy implementation

Utility data on strategy implementation provides regulators and stakeholders with information on past progress and future planned activities. Data translates ambitions (set during strategy development) into tangible investments the utility plans to pursue in the near term as necessary steps to deliver on its long-term vision and objectives. Strategic implementation data includes information on progress to date, future implementation, investments planned, costs and financing, and risks and mitigation. Utility data on *progress to date* describes past strategy implementation efforts, such as priorities established in previous distribution system plans. A narrative may be included to describe how the utility's priority investments support achievement of the distribution system strategy. In Michigan, for example, DTE Electric Company's 2023 distribution grid plan provided a summary of progress on strategic investments included in its prior plan to provide insight into how the utility has performed in delivering strategic objectives (Table 10-4). The narrative also can explain any delays in delivering previously proposed investments, which can support an assessment of any challenges faced by the utility and lessons learned, and can inform future investment decisions.

Table 10-4. DTE's progress on 2021 distribution grid plan strategic investments[170]

Investment	Progress
Technology and Automation	• Opened the new Electric System Operations Center (eSOC) in 2022 • Launched the Outage Management System (OMS) and Distribution Management System (DMS) components of Advanced Distribution Management System (ADMS) in February 2023
Pole Top Maintenance and Modernization (PTMM)	• Replaced 5,553 poles (2021-2022) through the PTMM program and on track to replace 3,353 poles in 2023
4.8kV Hardening	• Hardened 677 miles of overhead circuits in the city of Detroit and on track to harden 345 additional miles by the end of 2023
Tree Trim	• 80% of the system is now on a five-year tree trimming cycle and the company goal is to be 100% on cycle by the end of 2025
Conversion	• Energized two new 13.2kV substations in the city of Detroit (Corktown Substation and Island View Substation)

Utility information on *future implementation* can include a forward-looking description of how strategy implementation efforts are organized and managed and how they support stakeholder needs. For example, Consolidated Edison provides a narrative of its future implementation efforts for each topical area covered by its Distribution System Implementation Plan.[171]

[170] DTE, *2023 Distribution Grid Plan*, 2023, p 13
[171] Consolidated Edison, *Distribution System Implementation Plan*, June 2023

Data on *investments planned* can include the specific technologies the utility will invest in, as well as any alternatives considered in the technology selection process. Utilities also can provide information on functionalities enabled by selected technologies. For example, Portland General Electric's 2022 Distribution System Plan provided information on alternatives for proposed investments, including deploying NWAs to address system capacity needs.[172] In the case of the Eastport substation, the utility identified the need for near-term investments to address a capacity constraint. In addition to considering a traditional solution, including transformer and feeder upgrades at an estimated cost of $2.8 million, the utility analyzed NWAs such as energy efficiency, demand response, solar, and storage. Table 10-5 first shows the reliability violation for the substation that requires near-term investments, then summarizes the grid need and traditional and alternative investments analyzed.

Table 10-5. Portland General Electric's analysis of investment alternatives for Eastport Substation[173]

Parameter	Value under normal condition (N-0 condition)
Violation type	Planning criteria violation (thermal) for both the Eastport-Plaza feeder and Eastport WR1 transformer
Applicable areas for load relief	Entire scope of Eastport-Plaza and Eastport-76th feeders
Violation time and duration	1-7 PM, Summer weekdays, non-holidays

NWS candidate: Eastport-Plaza and Eastport WR1	
Scope of grid need	Planning criteria violation on Eastport-Plaza and Eastport WR1
	Violation seen on summer weekdays from 1pm-7pm
	Relief can be provided anywhere along the feeder and partially at the substation
Traditional solution	Substation transformer upgrade and feeder section reconductoring
NWS	Energy efficiency • 5,500,000 kWh/yr annual savings by 2032
	Demand response • 2,166 kW of summer peak demand potential by 2032
	Solar and storage • 2,940 nameplate kW-dc of residential rooftop solar PV • 743 nameplate kW-dc of non-residential rooftop solar PV • 1,000 nameplate kW-dc of Community Solar installations
Decision making metrics	Relief can be provided anywhere along the feeder and partially at the substation
Community engagement	Performed outreach to CBOs through four Community Workshops (see **Section 2.4**)
	Conducted outreach to schools and government partners in the affected area to align plans with existing efforts and potential projects
	Going forward, will conduct detailed community needs assessment for the Eastport area by working directly with CBOs with connections and existing relationships in the area (see the community needs assessment section of **Appendix E**)

[172] PGE, *Distribution System Plan Part 2*, 2022a
[173] PGE, *Distribution System Plan Part 2*, 2022a

Data on *cost and financing* can include information on the utility's approach to prioritize investments, the level of proposed spending required to achieve strategic objectives, and any alternative financing mechanisms that may have been considered. For example, DTE includes its Global Prioritization Model in its distribution grid plan filing, providing information on the utility's approach to prioritizing investments (Table 10-6). "Impact Dimensions" are the benefits the utility assesses for each investment. "Drivers" specify how the utility measures each benefit. The "Weight" indicates how DTE prioritizes various benefits. In this example, investments that support reduced electrical hazards, load relief, and reduced duration and frequency of outage events are ranked higher and selected for earlier investment.

Table 10-6. DTE's Global Prioritization Model[174]

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	• Reduction in wire down events • Reduction in secondary network cable manhole events	3
Overload Relief	• Elimination of overloaded equipment	
SAIDI	• Reduction in duration of outage events	
SAIFI	• Reduction in frequency of outage events	
Regulatory Compliance	• MPSC staff's recommendation (March 30, 2010 report) on utilities' pole inspection program • Docket U-12270 – Service restoration under normal conditions within 8 hours • Docket U-12270 – Service restoration under catastrophic conditions within 60 hours	2
	• Docket U-12270 – Service restoration under all conditions within 36 hours • Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	
Major Event Risk	• Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	• Elimination of system capacity constraints	
Investment in EJ Communities	• Percent of customers impacted by investment in EJ communities	
O&M Avoidance	• Trouble event reduction and truck roll reduction • Preventive maintenance investment reduction	1
Capital Avoidance	• Trouble event reduction and truck roll reduction • Reduction in capital replacement either during equipment failures or avoided planned capital work	

Utility data on *risks and mitigation* can include details on the methodology used to identify implementation risks, a description of the implementation risks identified, as well as the measures proposed to mitigate identified risks. For instance, Consolidated Edison provides a description of risks

[174] DTE, 2023 Distribution Grid Plan, 2023, p 167

and mitigation measures for each distribution system topic included in its 2023 Distribution System Implementation Plan.[175]

10.3 Best Practices

Best practices for sharing data on distribution system investment strategy and implementation include:

- Provide data and information to communicate the proposed distribution system evolution effectively. This can include the utility's articulation of its vision for the next 10 years and the associated objectives to deliver that vision.
- Include information on near-term capabilities and functionalities needed to modernize the distribution system. This can include a description of selected capabilities and supporting functionalities. Utilities also can indicate how these capabilities and functionalities support its vision of the distribution system vision and align with state policy goals, planning objectives, and priorities.
- Provide information on completed, ongoing, and future projects and initiatives necessary to achieve the long-term vision. This can include a strategic roadmap identifying projects and initiatives and their sequencing and relationships.
- Report on progress and future investment needs. This can include data on progress achieved on priorities established in previous distribution system plans and identification of future investment needs to achieve near-term and long-term goals.

[175] Consolidated Edison, *Distribution System Implementation Plan*, June 2023b

11. Geotargeted Programs

Geotargeted programs provide utility customer incentives for DERs to reduce load growth for specific locations on the distribution system and reduce the need for system upgrades. Utilities and third-party administrators provide an upfront rebate or other incentive for customers to install a specific technology (e.g., an energy-efficient appliance or smart thermostat), or offer opportunities for customers to earn revenues by operating qualifying technologies in ways that reduce peak demand on distribution circuits and substations—or provide both upfront and ongoing incentives. Geotargeted programs are another way to source non-wires alternatives (Chapter 12).

Geotargeted programs can leverage existing DER programs and customer relationships to address specific grid needs. That may reduce the timeline between identifying grid needs and deploying solutions. New geotargeted programs can leverage previous experience in program design, participant recruitment and retention, and impacts to facilitate program effectiveness.[176]

Utility data and analysis related to geotargeted programs can provide utility regulators and stakeholders with valuable information to understand and assess proposals for adapted or new DER programs, identify program needs, establish program design characteristics, evaluate program effectiveness, and make any adjustments necessary for continued program success. Table 11-1 is a summary of geotargeted program data and their impact on planning.

Table 11-1. Geotargeted program data categories and impacts on planning

Data category	Type of data reported	Impact of data on planning
Program needs	Program goals, locational characteristics, and operational and technical requirements	Defines suitability and technical characteristics of geotargeted programs to meet grid needs
Program design and deployment	Eligible measures, program duration, customer participation, and marketing, education, and outreach	Identifies program elements and deployment activities
Evaluation of program performance	Technologies and measures deployed, program effectiveness, community engagement, program budget, and cost-effectiveness	Supports decision-making on continuing and refining program design and deployment

11.1 Data Inputs

11.1.1 Geotargeted program needs

Utilities leverage data from distribution planning analyses, including grid needs assessments (Chapter 8), to identify suitable locations and other technical characteristics for geotargeted programs. Utilities can characterize geotargeted program needs by providing data on program goals, locational characteristics, and operational technical requirements.

[176] For more information on geotargeted programs, see Berkeley Lab's Interactive Decision Framework for Integrated Distribution System Planning.

Program goals: Information on outcomes typically includes the expected load reduction goal (e.g., kilowatt reduction) and total investment deferral. Data on program goals enables regulators and stakeholders to understand the anticipated magnitude of anticipated program achievements. Utilities in Michigan, Minnesota, New York, and Rhode Island have provided data on geotargeted program goals (Table 11-2).

Table 11-2. Examples of geotargeted program goals

State	Utility	Program	Geotargeted program goals		
			Type of investment deferral	**Investment deferral ($)**	**Peak load reduction**
MI	Consumers Energy	Swartz Creek[177]	Defer capacity upgrade, substation	$1.1 million	1.4 MW
MN	Xcel Energy	Geotargeted Distributed Clean Energy Initiative[178]	Defer capacity upgrade, transformer, and circuit	$4.1 million	500 kW
NY	Consolidated Edison	Brooklyn/Queens Demand Management Program[179]	Defer capacity upgrade, substation, and circuit	$1 billion	69 MW
RI	National Gird	Tiverton Pilot[180]	Defer capacity upgrade, 6 circuits	$2.9 million	1 MW

Locational characteristics: The grid needs assessment identifies distribution system assets suitable for geotargeted programs and locational characteristics. Data vary based on the grid need (e.g., circuit, transformer, substation) in the targeted location. Utilities can report locational characteristics using maps to provide a visual representation of targeted assets and locations. Data on locational characteristics may include customer information, such as customer accounts per class in the location targeted by the program. For example, for its Tiverton Pilot, National Grid in Rhode Island provided data on customer accounts per class served in the targeted area, total load (kilowatt-hour [kWh]) per class per year, and average load per account per year (Table 11-3). Such data help regulators and stakeholders understand potential program savings and inform decisions on the types of technologies and approaches (incentives, communications and customer engagement campaigns) that may be used to achieve program goals, such as peak load reduction.

[177] SEPA, *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*, 2018
[178] CEE, *Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report*, 2021
[179] NY DPS, Docket 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, August 2014
[180] SEPA, *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*, 2018

Table 11-3. Customers served by the Tiverton substation – National Grid, Rhode Island[181]

	Accounts	Load (kWh)	Average kWh Per Account Per Year
Residential	5,144	43,999,415	8,554
Commercial	470	10,292,822	21,900
Total	5,614	54,292,237	

Operational and technical requirements: Granular information on grid characteristics inform the timing of the grid need that the program will address, such as the months the grid need is observed. Other data may include the maximum number and duration of events the program will call. For instance, PG&E provided detailed information[182] on deferral needs that could be addressed by geotargeted programs and NWA solicitations for the 2023-2024 period, including targeted procurement (MW) per location, delivery month range, number of event calls per year, and day and hour range when those events would occur (Table 11-4).

Table 11-4. Data on distribution grid deferral needs – PG&E[183]

Deferral Need	Grid Need Location	Targeted Procurement (MW)	Delivery Month Range	Max Calls/ Year	Delivery Hour Range	Hours Duration	Delivery Day Range	In-Service Date
Camden 1106	Hardwick Bank 1	1.72	Jun-Aug	84	4PM-11PM	5	Mon-Sun	2026
	Henrietta Bank 5	1.73	Apr-Jul	39	12AM-4AM 4PM-9PM	4	Mon-Sun	2026
	Camden 1102	1.90	Jun-Aug	84	12PM-10PM	7	Mon-Sun	2026
Giffen Bank 2	Giffen Bank 1	10.57	Apr-Oct	197	12AM-12AM	24	Mon-Sun	2026
	Giffen 1103	0.20	Jun-Jul	30	12AM-2AM 6AM-11PM	5	Mon-Sun	2026
	Giffen 1102	CC	CC	CC	CC	CC	CC	2026
Green Valley Bank 4	Green Valley Bank 3	0.26	May-Oct	65	8AM-11AM 4PM-8PM	3	Mon-Fri	2026
	Green Valley Bank 2	2.19	Apr-Oct	153	7AM-12PM 4PM-8PM	7	Mon-Sun	2026

PG&E redacted data for the Giffen 1102 location (marked as CC, Customer Confidential), demonstrating

181 National Grid, *2012 System Reliability Procurement Plan*, November 2011
182 PG&E provided these data as part of its geotargeted programs conducted under its Distribution Investment Deferral Framework (DIDF) Partnership Pilot. Through these programs, the utility procuress Distributed Energy Resources (DERs) from third-party aggregators to avoid or defer distribution system investments. The CPUC approved these pilots in its Decision 21-02-006 of February 11, 2021.
183 PG&E, PG&E's Participants' Webinar, Distribution Investment Deferral Framework (DIDF) 2023-24 Partnership Pilot RFO, January 2024b

how customer privacy can be maintained in cases where providing granular data would reveal customer-specific data. The California Public Utilities Commission requires data to be redacted if it meets any of the following criteria, referred to as the 15/15 rule:[184]

- One single customer represents up to 15% of the total consumption
- There are less than 15 customers served by the asset[185]

PG&E also provides data on load profiles for assets targeted by the program. For instance, for the Green Valley Bank 4 deferral need, the utility provides load profiles for each month included in the delivery month range for the grid need, the summer rating for the facility targeted, and the load reduction needed to address the grid need (Figure 11-1).

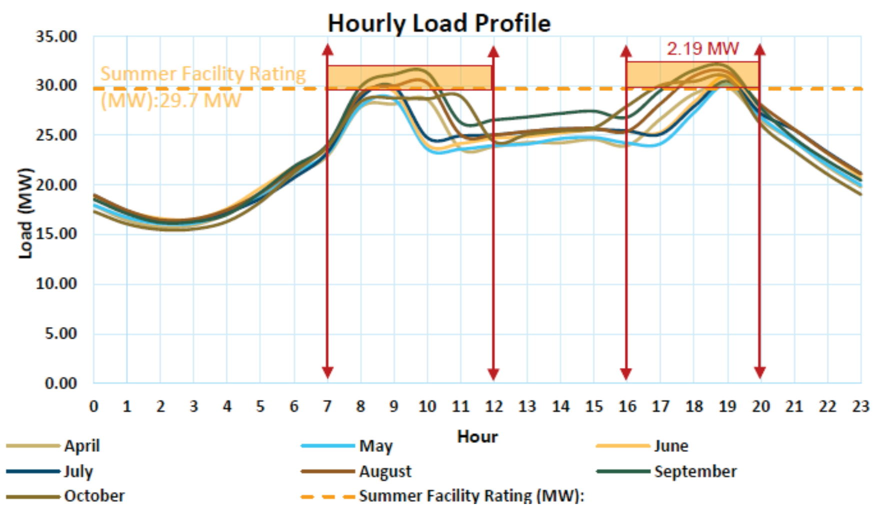


Figure 11-1. Hourly load profiles for Green Valley Bank 4 substation – PG&E[186]

11.2 Data Outputs

11.2.1 Geotargeted program design and deployment

Utility data on geotargeted program design informs approaches that can be pursued to address the grid needs selected. Data can include information on program deployment, measures eligible, program duration, customer participation, incentive types, and information on marketing, education, and outreach. Data on geotargeted program design allows regulators and stakeholders to assess program deployment plans and identify program design elements that may require additional detail and development.

[184] CPUC, Decision 14-05-016, Decision Adopting Rules to Provide Access to Energy Usage and Usage-Related Data While Protecting Privacy of Personal Data, May 2014b
[185] If third-party providers want to access customer confidential information to offer or participate in geotargeted programs, parties must sign a Non-Disclosure and Use of Information Agreement.
[186] PG&E, PG&E's Participants' Webinar, Distribution Investment Deferral Framework (DIDF) 2023-24 Partnership Pilot RFO, January 2024b

Information on *program deployment* specifies whether program delivery will be governed by the utility or a third party.

Information on *eligible measures* may include data on qualifying technologies for each customer class and participation targets. For instance, Table 11-5 provides a breakdown of measures that Xcel Energy in Minnesota included in its Geotargeted Distributed Clean Energy Initiative for residential and commercial customers.[187] The utility also describes the incremental customer participation needed (NWA incremental participation goal) to ensure the program achieves set goals.

Table 11-5. Data for energy efficiency measures – Xcel Energy's Geotargeted Distributed Clean Energy Initiative[188]

	Average annual participants (2015–2017)	NWA incremental participation goal	Total assumed 2019 participants	NWA incremental demand reduction (kW)
Residential lighting direct installation	20	130	150	23 kW
Residential light bulb giveaways	—	1,200 (bulbs)	1,200 (bulbs)	6 kW
Residential smart thermostat direct installation and demand response enrollment	18	80	98	72 kW
Commercial refrigeration efficiency	—	7	7	86kW
Commercial lighting efficiency	38	40	78	302kW
Commercial cooling efficiency	7	7	14	14 kW
Total demand reduction				**502 kW**

In addition, Xcel Energy benchmarked expected hourly measure performance against its program goal of delivering 500 kW of load reduction (Figure 11-2). The analysis shows how the utility expects new incentives for energy-efficient residential air-conditioning to reduce peak load (between hours 17:00 and 19:00). This type of data enables regulators and stakeholders to understand how the portfolio of selected measures contributes to program goals and assists decision-making for measures to be included in a geotargeted program.

[187] CEE, Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report, 2021
[188] CEE, *Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report*, 2021

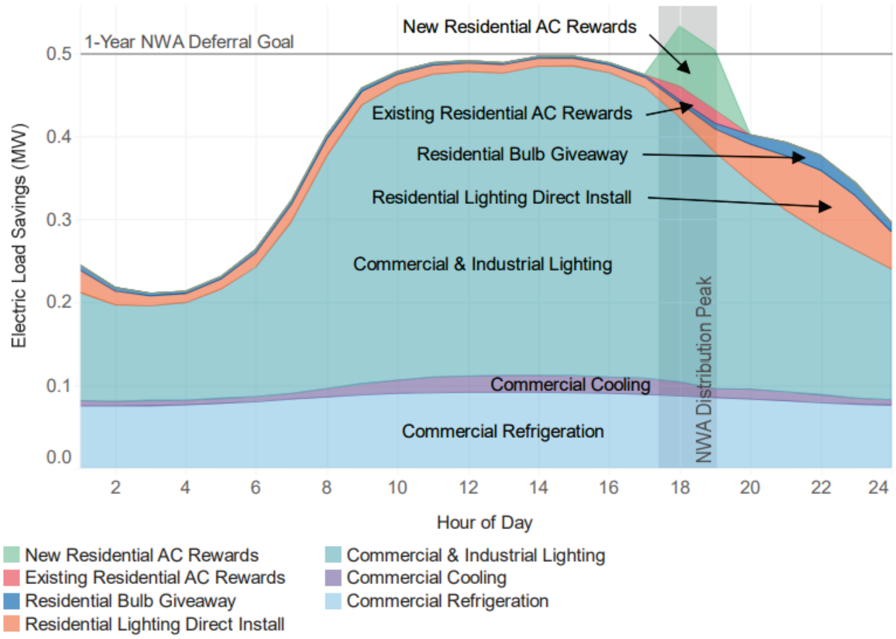


Figure 11-2. Expected measure performance – Xcel Energy's Geotargeted Distributed Clean Energy Initiative[189]

11.2.2 Evaluation of geotargeted program performance

Utilities can provide data on program effectiveness, community engagement activities, and budget to enable regulators and stakeholders to understand and assess the impact and outcomes of geotargeted programs implemented. These types of data can support decisions related to program continuity and identify any necessary changes to improve program performance to address changing grid need characteristics.

Program effectiveness: Data includes demand reduction (kW), including by customer class and measure implemented. For example, as part of its Brooklyn/Queens Demand Management Program,[190] Consolidated Edison reports quarterly on program performance, including peak load reduction achieved for customer program measures (e.g., energy efficiency, distributed generation, and distributed storage) and utility system measures (e.g., voltage optimization and energy storage located at a substation) and budget information (Table 11-6).

[189] CEE, Non-wires Alternatives as a Path to Local Clean Energy: Results of a Minnesota Pilot Geotargeted Distributed Clean Energy Initiative Update Report, 2021
[190] NY DPS, Docket 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, August 15, 2014

Table 11-6. Brooklyn/Queens Demand Management Program performance data for Q2 2024[191]

BQDM PORTFOLIO	2024		
	Quarter 2	Year-to-Date	Program-to-Date
FINANCIAL ACTIVITY ($ M)			
[0] Expenditures			
Customer-sided	$ 0.35	$ 0.40	$ 108.39
Utility-sided	$ 0.38	$ 0.80	$ 24.98
Total Expenditures	**$ 0.72**	**$ 1.21**	**$ 133.37**
Program Cost Recovery	**$ 1.74**	**$ 3.48**	**$ 82.14**
CUSTOMER-SIDED PROGRAM ACTIVITY			
Energy Efficiency			
[1] Residential Direct Install			
Peak Hour kW reduction	-	-	4,930
[2] Bring Your Own Thermostat			
Peak Hour kW reduction	-	-	391
[3] Residential AC			
Peak Hour kW reduction	-	-	9
[4] Multifamily Energy Efficiency			
Peak Hour kW reduction	3	3	5,685
[5] Small-Medium Businesses Adder			
Peak Hour kW reduction	16	26	14,962
[6] Commercial & Industrial			
Peak Hour kW reduction	92	92	1,078
[7] NYCHA			
Peak Hour kW reduction	-	-	2,293
[8] DCAS			
Peak Hour kW reduction	29	29	567
Distributed Generation			
[9] Fuel Cell			
Peak Hour kW reduction	-	-	6,100
[10] Combined Heat & Power			
Peak Hour kW reduction	-	-	3,079
Energy Storage			
[11] Peak Hour kW reduction	-	-	4,000
Customer-Sided Portfolio kW reduction at Peak Hour	**141**	**150**	**43,095**
UTILITY-SIDED SOLUTIONS			
Conservation Voltage Optimization (CVO)	-	-	17,000
Distributed Energy Storage System	-	-	1,500
BQDM Total kW reduction at Peak	**141**	**150**	**61,595**

Consolidated Edison also analyzes hourly load reductions delivered by the program and provides information on load reductions delivered during peak system hours (Figure 11-3). For example, the utility reported 23 MW of load reduction from customer measures during the peak hour (9 p.m. to 10 p.m.).

[191] Consolidated Edison, *BQDM Quarterly Expenditures & Program Report*, Second Quarter 2024

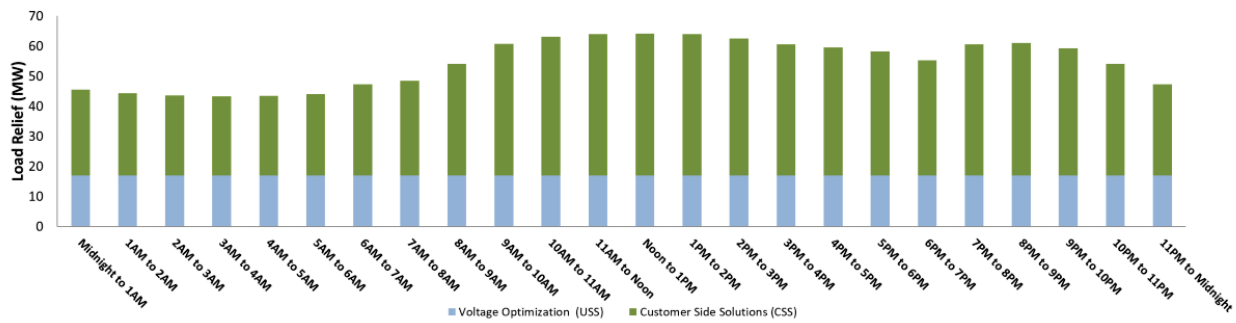


Figure 11-3. Brooklyn/Queens Demand Management Program load reduction data for Q2 2024[192]

Community engagement information can characterize utility efforts to engage local stakeholders during program design, implementation, evaluation, and improvements. Data can include types of community events held, target audiences, engagement goals, and event locations, venues, and outcomes. Data on community engagement efforts may provide regulators and stakeholders with information that informed the utility priorities and support program-related decisions.

Program budget information includes expenditures reported on a quarterly or yearly basis, with information for current period, annual period, and since the program start date. Utilities also can report program cost-effectiveness, including types of benefit-cost analysis tests and results. For instance, Central Hudson Gas & Electric Corporation in New York reports on cost-effectiveness of its Targeted Demand Management program annually. The data reported includes the test used and the results for the year (Table 11-7).

Table 11-7. Cost-effectiveness of Targeted Demand Management in 2023 – Central Hudson Gas & Electric Corporation[193]

BCA Test[a]	Results
Societal Cost Test	1.37
Utility Cost Test	1.35
Ratepayer Impact Measure	1.34

[a] Performed in accordance with Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 4.0. Case 16-M-0411 - In the Matter of Distributed System Implementation Plans, Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Distributed System Implementation Plan (filed on June 30, 2023).

Similarly, in Rhode Island, National Grid reported on the cost-effectiveness of its Tiverton Pilot using the Total Resource Cost test and providing historical data (Table 11-8).

[192] Consolidated Edison, *BQDM Quarterly Expenditures & Program Report*, Second Quarter 2024
[193] Central Hudson Gas & Electric, *Central Hudson Gas & Electric Corporation's 2023 Annual Report for the Targeted Demand Management (TDM) Program, a Central Hudson Non-Wires Alternative*, December 2023

Table 11-8. Cost-effectiveness of Tiverton Pilot, 2012-2017 – National Grid, Rhode Island[194]

System Reliability Procurement - Tiverton/Little Compton
Summary of Cost Effectiveness ($000)

	2012	2013	2014	2015	2016	2017	Overall
Benefits	**$179.0**	**$1,325.4**	**$1,033.3**	**$1,281.1**	**$687.7**	**$668.5**	**$5,175.0**
Focused Energy Efficiency Benefits[1]	$90.2	$1,015.1	$716.7	$1,024.8	$435.0	$497.6	$3,779.4
SRP Energy Efficiency Benefits[2]	$88.8	$310.4	$136.8	$78.0	$88.1	$11.3	$713.3
Demand Reduction Benefits[3]	$0.0	$0.0	$5.6	$6.8	$5.3	$11.4	$29.0
Deferral Benefits[4]	$0.0	$0.0	$174.2	$171.5	$159.4	$148.2	$653.3
Costs	**$133.4**	**$672.4**	**$569.3**	**$1,029.4**	**$611.1**	**$1,122.6**	**$4,138.3**
Focused Energy Efficiency Costs[5]	$46.6	$331.1	$195.8	$529.3	$280.1	$804.0	$2,186.9
System Reliability Procurement Costs[6,7]	$86.8	$341.3	$373.5	$500.2	$331.0	$318.6	$1,951.5
Benefit/Cost Ratio	**1.34**	**1.97**	**1.81**	**1.24**	**1.13**	**0.60**	**1.25**

Notes:
(1) Focused EE benefits in each year include the NPV (over the life of those measures) of all TRC benefits associated with EE measures installed in that year that are being focused to the Tiverton/Little Compton area.
(2) SRP EE benefits include all TRC benefits associated with EE measures installed in each year that would not have been installed as part of the statewide EE programs.
(3) DR benefits represent the energy and capacity benefits associated with the demand reduction events projected to occur in each year.
(4) Deferral benefits are the net present value benefits associated with deferring the wires project (substation upgrade) for a given year in $2014.
(5) EE costs include PP&A, Marketing, STAT, Incentives, Evaluation and Participant Costs associated with statewide levels of EE that have been focused to the Tiverton/Little Compton area. For the purposes of this analysis, they are derived from the planned ¢/Lifetime kWh in Attachment 5, Table E-5 of each year's EEPP in the SF EnergyWise and Small Business Direct Install programs. These are the programs through which measures in this SRP pilot will be offered.
(6) SRP costs represent the SRPP budget which is separate from the statewide EEPP budget, as well as SRP participant costs. The SRP budget includes PP&A, Marketing, Incentives, STAT and Evaluation.
(7) All costs and benefits are in $current year except for deferral benefits.
(8) 2012-2016 numbers have been updated to reflect year end data. 2017 numbers reflect year end projections.

11.3 Best Practices

Best practices for sharing data on geotargeted programs include:

- Provide data that specifies program goals. For example, the utility can specify the distribution system assets the program is targeting for deferral, the estimated cost of those assets, and expected cost savings.
- Share data on the locational and temporal characteristics of the targeted grid need and program operational requirements. This includes identifying the specific location of the targeted distribution system assets and the months, days, and hours for the specified grid need.
- Preserve customer privacy and confidentiality. Some states specify confidentiality requirements, such as the California 15/15 rule discussed above. In other states, utilities can develop their own processes to safeguard customer information, such as aggregating data at a level that does not reveal customer-specific information and, where that is not possible, redacting data. Utilities also can protect customer confidentiality by executing nondisclosure agreements for third parties to access sensitive customer load data.
- Report data on eligible measures and expected measure performance. This includes data describing specific technologies the program will deploy and, if applicable, eligible customer classes, as well as kilowatt savings by measure and customer class.
- Regularly report on program effectiveness and progress. Data can be reported quarterly, including total demand reduction achieved and breakdown by measure and customer class.

[194] National Grid, 2018 System Reliability Report, November 2017

- *Remove planning silos by integrating geotargeted program data in other planning analyses.* Direct utilities to analyze geotargeted programs as NWAs in distribution planning and program development and implementation processes, including filing methods and results.
- *Integrate geotargeted program outcomes data on future decision-making.* Use program data and lessons learned to inform future efforts and refine approaches, including participant recruitment and retention, incentive structure and levels, and types of program offerings.

12. Non-Wires Alternatives Procurements

Utilities can use DERs to provide grid services at specific locations on the distribution system to reduce, defer, or avoid the need for upgrades to infrastructure such as feeders and substations. NWAs can lower peak demand, address voltage issues, improve resilience, and reduce power interruptions through DERs sited on the utility system as well as at customer or community sites. Unlike geotargeted programs, NWAs rely on direct utility procurements or competitive solicitations of DERs, instead of customer programs administered by utilities or third parties.

Key inputs for NWA procurements that utilities can share include suitability criteria and technical and cost-effectiveness screens. Outputs include identified opportunities for NWAs, information on the procurement process, and NWA performance evaluation. Table 12-1 summarizes the types of data reported and their impacts on planning for each of these data categories.

Table 12-1. Summary of NWA procurement data and impacts on planning

Data category	Type of data reported	Impact of data on planning
Suitability screening	Criteria for determining whether NWAs are eligible to meet a specific grid deficiency — typically, project type, timing of the grid need, and cost threshold for a viable solicitation process	Identifies whether NWA processes and technologies are practical for addressing a specific grid need
Technical and cost-effectiveness screens	Methods and input assumptions for determining whether NWAs can resolve a grid need cost-effectively	Determines whether NWAs qualify to compete against the utility's traditional solution to meet a specific grid need
NWA opportunities	Detailed descriptions of grid needs for NWA solicitations, including location, timing, and magnitude of grid need	Prescribes how NWAs must perform and informs their selection and operation
Procurement process	Timeline, review process including bid evaluation criteria, bidding rules	Sets expectations for NWA providers on how the utility procures NWAs
Performance evaluation	Data requirements, data cleaning, and performance metrics	Validates utility assessment for achieving expected outcomes

12.1 Data Inputs

12.1.1 Suitability screening

The utility develops screening criteria to help identify distribution system needs that may be suitable for NWA solutions. Criteria include the project type (some grid needs may exclude NWAs from consideration), timing of the grid need (to ensure sufficient lead time for procurement), and cost of the traditional distribution infrastructure solution that otherwise would be built (a threshold below which the utility's time and effort for NWA analysis may not be justified).

Screening criteria help regulators and stakeholders understand key factors that affect whether an NWA could potentially address grid needs. Utilities can share proposed criteria for review by regulators and stakeholders, who may propose alternative criteria for consideration.

Criteria for project type may include the types of distribution infrastructure where NWAs may address grid deficiencies, operating conditions, and characteristics of the grid need. In Minnesota, for example, Xcel Energy limits NWAs to non-network and non-single bank substations under N-0 conditions.[195] Grid need characteristics may be as general as reliability[196] or be specific such as thermal overloads and voltage issues.[197] Utilities also may specify eligible grid services. For example, NV Energy identifies energy and peak demand reductions and load shifts as acceptable services that NWAs can provide.[198] In addition, utilities can include criteria on the scope of the grid need. Xcel Energy, for example, only allows NWAs to address grid needs that occur for fewer than 5,840 hours a year.[199]

Timing criteria can include both the minimum and maximum time until the utility must address a grid need. The minimum timeline reflects the time required for contracting, installing, and evaluating an NWA. NWA projects may not be feasible if a utility anticipates grid needs in the short term. The minimum timeline may depend on the affected part of the distribution system. Consolidated Edison's minimum timeline for projects at the feeder level is 18 months— half as long as the 36 months for projects on a major circuit or substation (Table 12-2). The maximum timeline generally reflects the length of the planning period in which the utility has identified grid constraints.[200] [201]

Minimum project cost thresholds address whether it is practical for the utility to conduct an NWA solicitation. As with timelines, utilities can differentiate cost criteria based on the part of the distribution system in question. Consolidated Edison, for example, offers NWA opportunities for planned utility projects at the feeder level that cost at least $450,000, but does not set a cost minimum for substation-level projects (Table 12-2).[202] Other utilities provide a single minimum project cost, such as Ameren's $3 million threshold.[203]

195 Xcel Energy, Minnesota, Integrated Distribution Plan 2024-2033, Appendix B1Grid Modernization, November 2023
196 Central Hudson Electric & Gas, Non-Wires Alternatives Opportunities
197 NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
198 NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
199 Xcel Energy, Minnesota, Integrated Distribution Plan 2024-2033, Appendix B1Grid Modernization, November 2023
200 NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
201 Xcel Energy, Colorado, Distribution System Plan, May 2022
202 Consolidated Edison, Distribution System Implementation Plan, June 2023
203 Ameren Illinois, Multi-Year Integrated Grid Plan, January 2023b

Table 12-2. Consolidated Edison NWA suitability criteria[204]

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief or Load Relief in combination with Reliability.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450,000

Utilities can describe how they prioritize acquisition of NWAs that pass suitability screens. NYSEG, for example, prioritizes NWA acquisition based on forecasted timing of the associated grid need.[205] SDG&E uses metrics for cost-effectiveness, uncertainty of the grid need forecast, and likelihood that the utility can source NWAs.[206] Transparency into how utilities prioritize NWA procurement helps regulators, stakeholders, and bidders for NWA contracts understand the order in which the utility will acquire NWAs offered in utility solicitations.

12.1.2 Implementation and cost-effectiveness screens

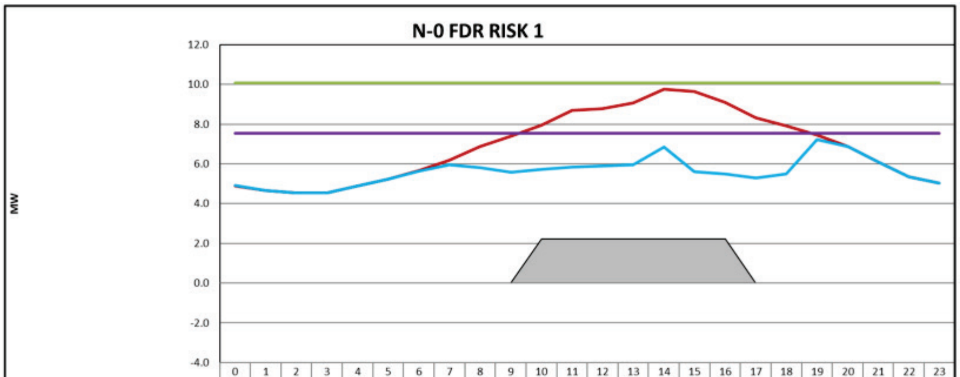
Utilities apply technical and cost-effectiveness screens to determine whether to pursue NWAs they have deemed suitable for known grid needs.

Technical screens include eligible technologies, modeling tools, and key decisions in modeling NWA performance. NV Energy, for example, describes how its NWA Screening Analysis Tool considers the impact of solar PV, battery storage, energy efficiency, demand response, and conservation voltage reduction on distribution system constraints.[207] The utility also documents assumptions on the maximum installed AC PV capacity (5 MW) and maximum load reductions from energy efficiency (2%) that it uses in the screening tool. In addition, the utility presents the capacity of each DER selected by the screen tool.

Transparency of utility assumptions in technical screens helps regulators and stakeholders understand factors that influence screening results and potentially propose alternative screening criteria. In its 2023 Integrated Distribution Plan for Minnesota, Xcel Energy describes its assumed 25% error in the peak forecast when assessing NWA solutions.[208] Figure 12-1 illustrates how this assumption affects the

[204] Consolidated Edison, Distribution System Implementation Plan, June 2023
[205] New York State Electric and Gas, Non-Wires Alternatives
[206] San Diego Gas & Electric, 2023 Grid Needs Assessment and Distribution Deferral Opportunity Report, August 2023
[207] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[208] Xcel Energy Colorado, Distribution System Plan, May 2022

screening process. The utility assesses NWA performance (blue line) relative to 75% (purple line) of a feeder's capacity limit (green line). This forecast error assumption increases the energy and demand reductions required for NWAs. Xcel Energy also documents characteristics of the technologies it includes in the technical screen, including battery roundtrip efficiency.[209]



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Feeder Load (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.7	6.2	6.9	7.4	8.0	8.7	8.8	9.1	9.8	9.7	9.1	8.3	7.9	7.5	6.9	6.1	5.3	5.0
Forecast Uncertainty Margin (MW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Feeder Load With NWA (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.6	5.9	5.8	5.6	5.7	5.8	5.9	5.9	6.9	5.6	5.5	5.3	5.5	7.2	6.9	6.1	5.3	5.0
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-1.1	-1.8	-2.2	-2.9	-2.9	-3.1	-2.9	-2.6	-2.1	-1.5	-0.9	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Figure 12-1. Load profile for at-risk feeder in Xcel Energy Minnesota 2023 Integrated Grid Plan[210]

For cost-effectiveness screens, utilities can report discount rates and benefit and cost assumptions.[211] [212] [213] Transparency into these assumptions helps regulators and stakeholders validate utility decisions and propose alternative assumptions and methods. Utilities also can summarize the expected net benefits (see Table 12-3) and compare them to the cost of traditional solutions. The summaries make clear what costs and benefits drive the cost-effectiveness determination. For additional details on cost-effectiveness data that utilities can share in distribution system plans, see Chapter 9, Cost-Effectiveness Evaluation for Investments.

[209] Xcel Energy Colorado, Distribution System Plan, May 2022
[210] Xcel Energy Colorado, Distribution System Plan, May 2022
[211] Xcel Energy Colorado, Distribution System Plan, May 2022
[212] NV Energy, Distributed Energy Resource Plan Update for 2024, September 2023
[213] PGE, 2022 Distribution System Plan, Chapter 6. Non-wires solutions, 2022b

Table 12-3. Summary of NWA net benefits in Xcel Energy's Integrated Grid Plan for Minnesota[214]

Cost/Benefit Category	Incremental Impact	
Energy Generation	$	400,266
Generation Capacity + MISO Reserves	$	122,602
Transmission Capacity	$	5,830
Deferral Benefit	$	627,936
GHG Emissions + Other Environmental	$	623,658
Solar Cost	$	(504,285)
Battery Cost	$	(118,130)
Interconnection Fees	$	(34,000)
Total Benefit	**$**	**1,780,292**
Total Cost	**$**	**(656,415)**
Net Impact	**$**	**1,123,876**

12.2 Data Outputs

12.2.1 NWA opportunities

Utilities can identify and describe which deficiencies listed in the grid needs assessment will be included in NWA solicitations. Utilities can provide these descriptions in distribution system plans as well as in requests for proposals. The descriptions provide data on the context, timing, and magnitude of the grid need (see Table 12-4). These data convey how the NWA must perform to meet specific grid needs and help project developers and DER aggregators assemble a portfolio of NWAs. For example, energy and demand reduction requirements can inform the size and dispatch strategy for battery storage. Locational information such as feeder IDs and names helps developers access hosting capacity through utility-published maps and associated data. Data on the timing of the grid need sets expectations for participation by customers hosting DERs. In addition, the maximum number of events that a utility may call for demand response, for example, could affect a customer's willingness to participate.

[214] Xcel Energy, Colorado Distribution System Plan, May 2022

Table 12-4. Data on grid need for NWA Request for Proposals[215] [216] [217]

Grid need context	Narrative description of project
	Location
	Substation/feeder names
	Voltage of affected equipment
	Count of customers by service class served by equipment
	Traditional utility investment that NWA could replace
	Contingency in which need arises (e.g., N-0 vs. N-1)
Magnitude of grid need	Maximum daily energy need
	Maximum MW needed
Timing of grid need	Date by which NWA must be in service to address need
	Number of years that NWA must resolve grid need
	Days of week in which event could occur
	Hours in which event could occur
	Event duration
	Maximum number of events per year
	Maximum number of consecutive days with events

12.2.2 Procurement process

Utilities generally procure NWAs through competitive bidding. Key elements of the procurement process that utilities can share include the procurement timeline, review process including bid evaluation criteria, and bidding rules. Figure 12-2 illustrates Xcel Energy's solicitation timeline and milestones for its Colorado service area. A clear timeline sets expectations for regulators and NWA vendors and creates accountability for utilities. Documentation of the utility's review process can include standards or metrics for evaluating proposals (e.g., cost-effectiveness methodology) and the role of an independent evaluator to review bids.[218] [219] Bidding rules can include the minimum size of the bid. National Grid, for example, includes a minimum bid size of 100 kW in its 2024 request for proposals for one of its substations.[220] In its 2023 Integrated Grid Plan, Hawaiian Electric describes how

[215] National Grid, Request for Proposal, October 2024b
[216] Hawaiian Electric, Integrated Grid Plan, May 2023
[217] Xcel Energy, Colorado, Distribution System Plan, May 2022
[218] Xcel Energy, Colorado, Distribution System Plan, May 2022
[219] Hawaiian Electric, Integrated Grid Plan, May 2023
[220] National Grid, Request for Proposal, October 2024b

it plans to adapt to situations in which bids do not address the entire grid need, the NWA contractor does not install the planned measures, and the NWA does not operate as needed. By establishing how they plan to handle such contingencies, utilities can assure regulators that they are prepared to handle unexpected outcomes from NWAs and address grid needs.

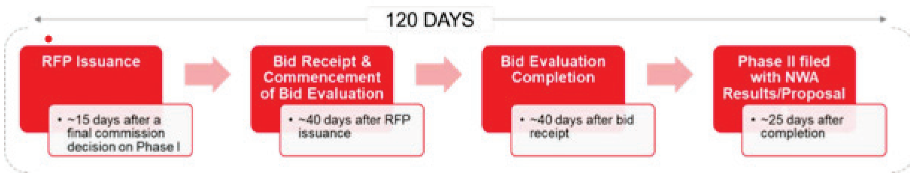


Figure 12-2. Xcel Energy Colorado NWA solicitation process[221]

12.2.3 Performance evaluation

Data on NWA performance evaluation can include data requirements, data cleaning, and performance metrics. For example, Consolidated Edison's performance verification plan states that it requires real power production, voltage, amperage, and power factor among other data points to evaluate the impact of NWAs.[222] The utility also describes how it excludes the lowest 5% of hourly generation measurements when calculating average reductions in energy needs due to distributed generation during grid need hours. Reporting on such methodological assumptions helps regulators and stakeholders assess utility decisions and suggest alternative assumptions or methods for consideration. Performance metrics defined before NWA solicitations are issued can promote successful implementation by helping NWA vendors prepare to submit solutions that achieve the desired outcomes.[223] Consolidated Edison, for example, provides metrics for distributed generation and storage, including Average Event Load Reduction (see Figure 12-3).[224]

$$AELR_M = \left(\frac{\sum_{i=E_{start}}^{i=E_{end}} kWh_i}{E_{end} - E_{start}} \right) + EC_M$$

Where,

kWh_i	Electricity discharged per hour interval i (charging will result in negative kWh values)
i	Each hourly interval during NWS Event
M	NWS Event Day
EC_M	Energy Charged on Event Days

Figure 12-3. Metric used for battery storage performance for Consolidated Edison NWAs

[221] Xcel Energy Colorado, Distribution System Plan, May 2022
[222] Consolidated Edison, Performance Verification Plan, May 2022
[223] National Grid, Request for Proposal, October 2024b
[224] Consolidated Edison, Performance Verification Plan, May 2022

12.3 Best Practices

Best practices for data sharing on NWA procurements include:

- Establish appropriate lead times for grid needs identification, NWA planning, procurement, and deployment.
- Conduct inclusive and collaborative stakeholder engagement processes to align NWA procurement with community needs and public interests.
- Establish transparent rules for NWA ownership and operation.
- Clearly describe criteria for NWA suitability, informed by stakeholder input.
- Document methods and assumptions for technical and cost-effectiveness screening.
- Present detailed information on NWA opportunities, including:
    - Locational information (e.g., feeder ID)
    - Timing of grid need (e.g., months and hours)
    - Magnitude of grid need (e.g., MW of demand reduction required).
- Provide adequate grid data to developers for competitive solicitations for NWAs.
- Use a technology-agnostic portfolio approach for NWAs.
- Consider contingency planning for procured NWA projects (e.g., acquire excess NWA capacity) to reduce risk associated with non-performance.
- Implement standard pro forma agreements for NWAs.
- Offer vendor pre-qualification options to reduce procurement timeline.
- If viable NWA bids are insufficient to meet the identified grid need, consider combining NWAs with utility infrastructure upgrades to meet the same need at lower cost compared to the standalone utility solution.
- Provide a performance evaluation framework that includes data requirements and performance metrics.
- Use data and lessons learned from completed NWA procurements and implementation to inform future efforts and refine approaches.

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APPENDIX A. Organizations Interviewed

Utilities
National Grid, New York
Portland General Electric
Public Service of Colorado

Public Utility Commissions
Illinois Commerce Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
New York Department of Public Service
Rhode Island Public Utilities Commission

State Energy Offices
Massachusetts Department of Energy Resources
Minnesota Department of Commerce

Mind the Regulatory Gap

How to Enhance Local Transmission Oversight

Report / November 2024

Authors and Acknowledgments

Authors
Claire Wayner
Kaja Rebane (formerly RMI)
Chaz Teplin

All authors from RMI unless otherwise noted.

Contacts
Claire Wayner, cwayner@rmi.org
Chaz Teplin, cteplin@rmi.org

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Claire Wayner, Kaja Rebane, and Chaz Teplin, *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight*, RMI, 2024, **https://rmi.org/insight/mind-the-regulatory-gap**.

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All images used are from iStock.com unless otherwise noted.

Acknowledgments
The authors would like to thank the following individuals for their helpful contributions to this report, such as participating in interviews and reviewing early drafts. All errors remain our own.

Commissioner Davante Lewis, Louisiana Public Service Commission
Former Commissioner Ted Thomas, Arkansas Public Service Commission
Former Chairman Kent Chandler, Kentucky Public Service Commission
Don Kreis, New Hampshire Office of the Consumer Advocate
Chairman Phil Bartlett, Maine Public Utilities Commission
Commissioner Sarah Freeman, Indiana Public Utilities Commission
Erik Hanser, Michigan Public Service Commission
Charlie Inman and Aaron Cahen, Washington Utilities and Transportation Commission
Brian Lipman, New Jersey Division of Rate Counsel
Chairperson Andrew French, Kansas Corporation Commission
Ed Smeloff, consultant
Josh Walters, Connecticut Public Service Commission
Greg Poulos, Consumer Advocates of PJM States
Ari Peskoe, Harvard Electricity Law Initiative
Josh Macey, Yale Law School
Nick Lawton, Earthjustice
Nick Guidi, Southern Environmental Law Center

Acknowledgments, *continued*

Tyler Farrell, RMI
Rachel Gold, RMI
Bev Bendix, RMI
Carina Rosenbach, RMI
Camden Burk, formerly RMI

About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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Executive Summary

In the coming years, the United States will need to substantially expand the capacity of its electric transmission grid to replace aging infrastructure, accommodate load growth from data centers and end-use electrification, interconnect low-cost clean generation, and ensure reliability and resilience in the face of increasingly severe weather. Transmission expansion will require significant new investment — yet many Americans already struggle to pay their monthly electricity bills. To achieve affordability through the clean energy transition, it will therefore be essential for planners and regulators to ensure that ratepayer money is spent efficiently.

To expand the transmission grid in an efficient manner, smart planning is essential. A key ingredient of this will be ensuring the right mix of **local projects** (those that are built by a single utility to meet needs within its own footprint) and **regional projects** (those that are regionally planned to meet multiple utilities' needs). To achieve the needed local and regional balance, all transmission projects will need to receive the appropriate regulatory scrutiny, including identifying where local projects could be scaled up to simultaneously meet regional needs (a process known as **right-sizing**[i]).

Today, however, there is a **regulatory gap**. Local projects are receiving little oversight. This gap results from a number of factors, including:

- Regional planning entities, such as regional transmission organizations (RTOs) and independent system operators (ISOs), consider local projects outside of their purview;
- The Federal Energy Regulatory Commission (FERC) assumes project costs were prudently incurred unless stakeholders can prove otherwise; and
- State public utility commissions (PUCs) often have limited oversight authority when it comes to local projects.

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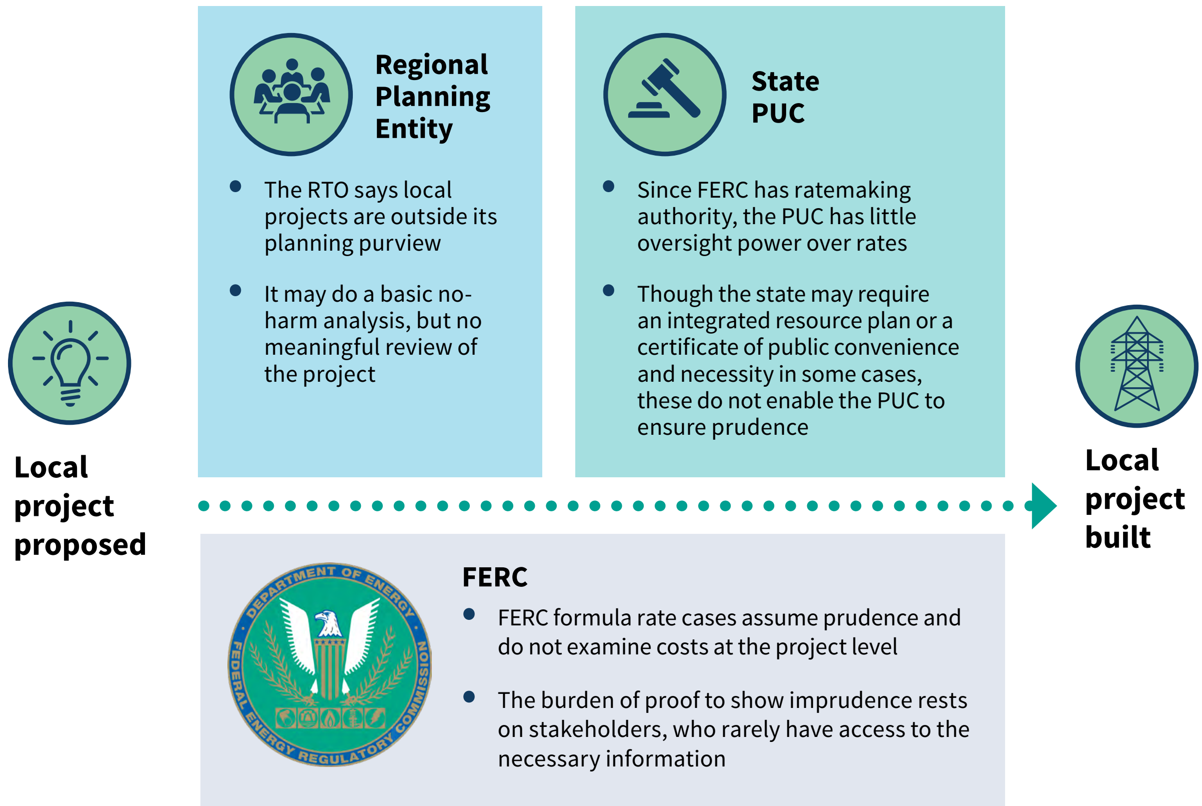
i Right-sizing means considering whether a larger project could better meet both local and regional needs than the smaller project. It is a vital aspect of sound planning because often a single large project is able to more cost-effectively meet multiple needs than a series of individually planned small projects, while reducing total land use and environmental impacts.

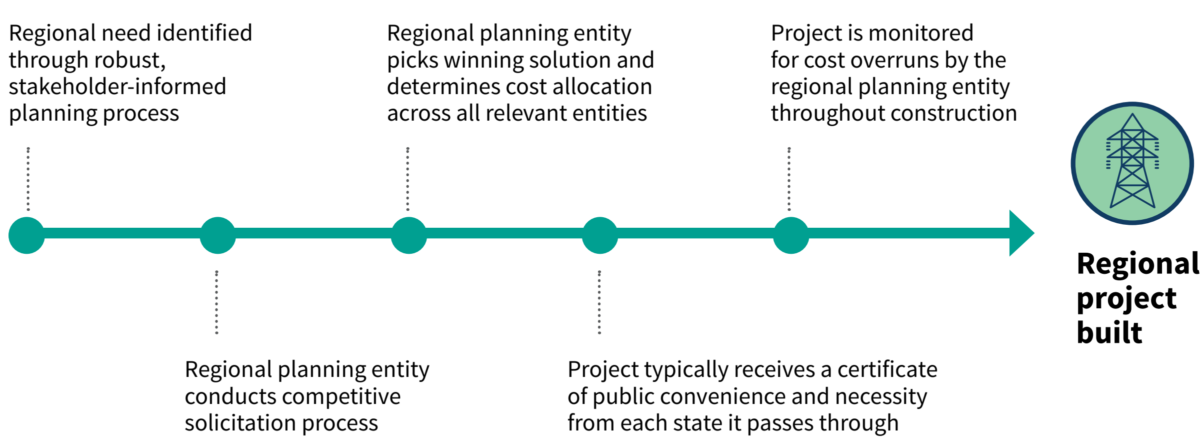
Exhibit ES1 summarizes the main factors that contribute to the regulatory gap. Exhibit ES2 then compares the lack of review that local transmission projects receive to the robust review process for regional projects.

Exhibit ES1 The Regulatory Gap for Local Transmission Projects



RMI Graphic.

Exhibit ES2 Regional Transmission Project Review Process



RMI Graphic.

As illustrated in Box ES1, this regulatory gap has corresponded with a broad nationwide shift in transmission spending from regional transmission projects to local projects. This shift can in part be attributed to the incentives created by a lack of accountability resulting from the regulatory gap, as we explore further in this report.

Box ES1

Evidence of the Shift in Transmission Spending to Local Projects

- According to the FERC *State of the Markets 2021* report, since 2014, the percentage of spending on transmission projects in the United States with voltages of 230 kilovolts or higher has been steadily declining, from 72% in 2014 to just 34% in 2021.[1]
- A recent analysis by Grid Strategies found that while transmission spending hit an all-time high in 2023, the United States built only "20% as much new transmission [mileage-wise] in the 2020s as it did in the first half of the 2010s." Only 55 miles of new high-voltage transmission were added in 2023, compared to a record 4,000 miles in 2013.[2]
- Analysis by the Brattle Group found that 90% of recent transmission spending has been on lower-voltage reliability upgrades, with 50% of all spending going toward local projects.[3]

Regional trends, where data is readily available, confirm these national trends.

- In the mid-Atlantic (PJM Interconnection), spending on local projects (i.e., Supplemental projects) increased from 9% of total spend from 2005 to 2013 to 73% of total spend from 2014 to 2021.[4]
- In New England (ISO New England), spending on local projects (i.e., asset condition projects) increased eightfold from 2016 to 2023.[5]
- In the Midwest (Midcontinent Independent System Operator), local projects (i.e., Other projects) have increased from 54% of total spend in 2017 to 78% in 2022.[6]
- In California (California Independent System Operator), 63% of projects from 2018 to 2022 were local (i.e., self-approved projects) and thus not eligible for state or regional review.[7]

We identified the regulatory gap and its impacts through interviews with state regulators, consumer advocates, and others, as well as review of FERC filings and related evidence. We recommend 11 regional, federal, and state reforms to address the regulatory gap:

Regional Reforms

- Regional planning entities can **implement regional-first planning**, which we describe further in Exhibit ES3. Regional-first planning would ensure right-sizing is considered for all local needs. FERC could require regional-first planning or individual regional planning entities could adopt it on their own.
- FERC can **standardize local project definitions and tracking** across regional planning entities.
- FERC and regional planning entities can **strengthen state input and influence at the regional level**.

Federal Reforms

- FERC could **reform the formula rate process** to apply only to projects that receive adequate regional and/or state review. This could help address the cause of the regulatory gap by enabling greater scrutiny of local project expenditures to ensure prudence.
- FERC could **establish an independent transmission monitor** (ITM), either a single federal ITM or one for each planning region.
- FERC could **explore performance-based regulation** for transmission.

State Reforms

- Some states require PUCs to approve transmission projects through the issuance of a certificate of public convenience and necessity (CPCN). State PUCs can **leverage and expand CPCN authority** for local transmission projects.
- PUCs could **offer expedited cost recovery** for local projects that have undergone a robust regional review, rather than making expedited recovery via rate riders the default option for all transmission costs.
- PUCs could **update integrated resource plans** (IRPs) to incorporate transmission, including regional-first planning.
- States could **create and fully leverage electric transmission authorities**, which are independent bodies established to coordinate transmission development, to help enable regional-first planning.
- State legislatures and others could **help PUCs grow their regulatory staff capacity and expertise** to more effectively conduct oversight where they have existing authority.

Exhibit ES3 Components of Regional-First Planning

Utilities submit proposed local needs. Transmission owners submit anticipated local needs at the start of each regional planning cycle, whether it involves planning over the short term or the long term.

Planning entity identifies the region's needs. The regional planning entity determines all regional needs holistically in addition to submitted local needs

Planning entity identifies the best solutions. The regional planning entity determines the best solutions to the identified local and regional needs, including whether local projects can be right-sized to meet regional needs and whether alternative transmission technologies can be utilized.

Transmission owner optionally submits additional local projects. Following the regional planning entity's identification of solutions, each transmission owner can propose additional local projects for consideration if they feel there are unmet local needs. Such projects must still undergo state and federal review and may be held to a higher standard.

RMI Graphic.

Continuing the status quo approach to transmission planning, which separates local and regional planning, perpetuates this regulatory gap and is an inherently inefficient way to expand the grid. Many uncoordinated local projects will generally be more costly than larger, well-planned regional projects, and they will also tend to have greater land use and environmental impacts.[ii] Additionally, well-planned regional projects can offer significant economic, operational, and emissions reduction benefits that local projects may not offer.[iii] This approach also misses a key opportunity to proactively design the grid of the future rather than simply rebuild the grid of the past.[iv] Although regional planning can require a considerable up-front investment in time and resources to produce high-quality results, we believe that this investment is essential to produce the most beneficial results for customers as well as better land use and environmental outcomes.

ii Even if a regional project is built at larger scale to meet local needs in addition to regional ones, it can reduce land use and environmental impacts by obviating the need for additional local projects. In contrast, if local needs are separately addressed via several locally planned projects, the overall result is likely to have more land usage and related environmental impacts.

iii Well-planned regional projects such as MISO's Multi-Value Projects process and Texas's Competitive Renewable Energy Zones process have been credited with returning significant economic benefits to the grid. In contrast, local projects almost always lack even a simple cost-benefit analysis ("Texas as a National Model for Bringing Clean Energy to the Grid," Americans for a Clean Energy Grid, October 13, 2023, **https://www.cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/;** and *MTEP17 MVP Triennial Review,* MISO, September 2017, **https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf)**.

iv For an example of the missed opportunities that can arise when we do not plan proactively for the grid of the future, please refer to the following resource on the post–Hurricane Maria grid rebuild in Puerto Rico: Isaac Toussie et al., *The Role of Renewable and Distributed Energy in a Resilient and Cost-Effective Energy Future for Puerto Rico,* RMI, December 2017, **https://rmi.org/wp-content/uploads/2017/12/Insight_Brief_Puerto_Rico_Resilient_CostEffective_Energy.pdf.**

Each of the reforms we identify addresses a different aspect of the regulatory gap, and if adopted together they would complement one another. Therefore, we recommend that actors at the regional, federal, and state levels pursue appropriate reforms in parallel. Exhibit ES4 illustrates our proposed reforms to alleviate the regulatory gap by geographic level. Taken together, these could help address the regulatory gap, improving the quality of transmission planning in the United States and producing better results for customers and society.

Exhibit ES4 Proposed Reforms to Alleviate the Regulatory Gap

Geographic Level	Proposed Change
Regional	• Implement regional-first planning • Standardize local project definitions and tracking • Strengthen state input and influence at the regional level
Federal	• Reform the formula rate process • Establish an ITM • Explore performance-based regulation for transmission
State	• Leverage and expand CPCN authority • Offer expedited cost recovery for local projects that have undergone a robust regional review • Update IRPs to incorporate transmission • Create and fully leverage electric transmission authorities • Grow regulatory staff capacity and expertise

Note: Multiple parties across geographies may need to take action to fully realize some reforms. For instance, implementing regional-first planning will likely require action by FERC.

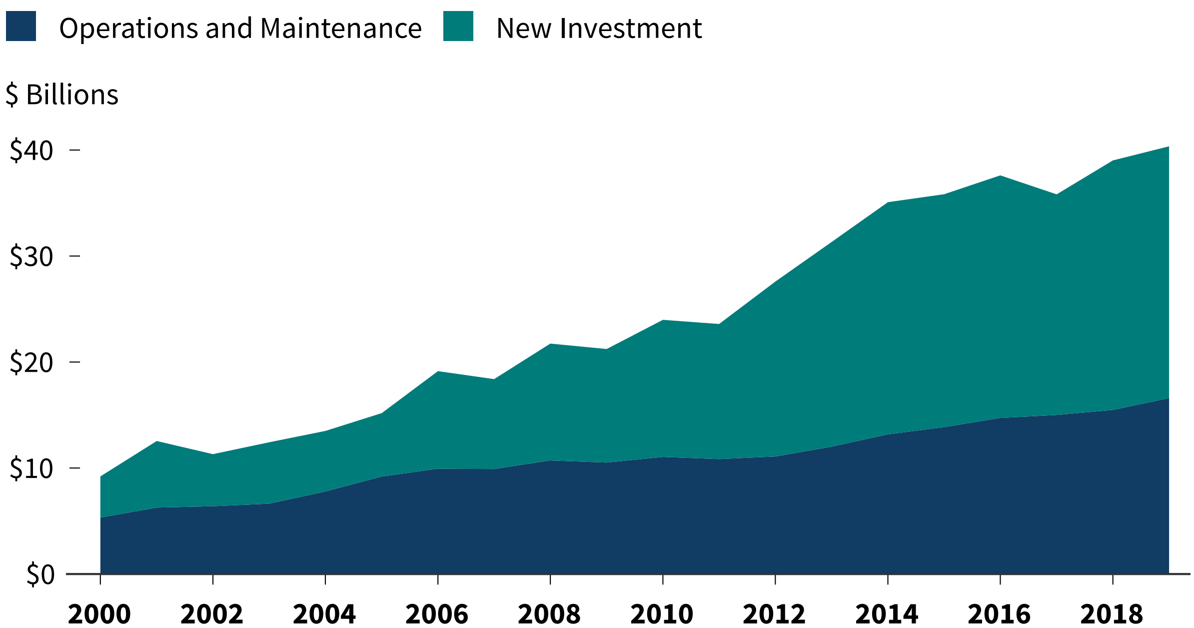
RMI Graphic.

Introduction: The Regulatory Gap

Across the country, transmission spending has been rising rapidly, driven by a combination of needs including replacing aging infrastructure, connecting new generation resources, and addressing load growth. The US Energy Information Administration found in 2021 that spending on the electric transmission system has increased almost fivefold in the past two decades, from $9.1 billion in 2000 (2019 dollars) to $40 billion in 2019.[8] Looking ahead, the clean energy transition is going to require even greater investment in transmission to connect new low-cost generation resources to load centers — up to a 60% increase in total transmission capacity by 2030 and a tripling by 2050, according to researchers at Princeton University.[9]

Exhibit 1

Annual Utility Spending on the US Transmission System (2000-19)



RMI Graphic. Source: US Energy Information Administration

The need for more transmission will best be met through efficient regional planning to ensure that cost-effective solutions are developed at scale. However, in recent years, there has been a dramatic shift in spending by utilities from regional projects, which are centrally planned at the regional level by federally designated regional planning entities, to local projects, which are planned and built by a single utility to meet needs within that utility's footprint.[v] The Federal Energy Regulatory Commission (FERC), for instance, recognized in 2022 that the "vast majority of investment in transmission facilities" in the past decade "has been in local transmission facilities."[10]

v For more data on this spending shift, see the section *Consequences of the Regulatory Gap*.

Box 1

Defining Local Transmission Projects

We define a **local project** as a project planned and built by a single utility to meet needs within that utility's footprint (i.e., transmission zone). These needs may include replacing aging infrastructure (this is typically called an asset management project), interconnecting new loads, enhancing operational flexibility, and ensuring that local reliability standards are met. Local projects go by different names in different grid regions; for example, asset condition projects in New England (ISO New England), self-approved projects in California (California Independent System Operator), Supplemental projects in the mid-Atlantic (PJM Interconnection), and Other projects in the Midwest (Midcontinent Independent System Operator). Local projects differ from regional projects, which are planned at the regional level and may span multiple utilities' footprints. In contrast to regional projects, local projects are frequently not thoroughly reviewed by regional planning entities, as we explore in the ***How Local Projects Are Currently Considered in Regional Planning*** section.

One of the key reasons behind this shift in spending is a lack of sufficient state, regional, or federal oversight of local projects, which we refer to as the **regulatory gap**. At the state level, local projects are often legislatively exempted from review by the public utility commissions (PUCs) that regulate utilities.[vi] State regulators may not become aware of projects until after the utility has already begun advanced planning or construction, and projects are not typically tracked during the construction process for potential cost overruns.[vii] At the regional level, regional transmission planning entities generally claim that local projects are not within their purview. At the federal level, oversight has been streamlined in ways that provide very limited project-level review. As a result, local transmission projects often receive little scrutiny, offering utilities a low-risk investment opportunity compared to regional projects, which are required to undergo significantly more oversight.[viii]

The timing for this recent shift in spending to local projects could not be worse. At a time when the US grid needs to significantly expand its capacity to prepare for the parallel demands of load growth and the clean energy transition, utilities are choosing to invest primarily in local projects, with no mechanisms in place to ensure that these projects are being adequately reviewed by planners and regulators. Relying heavily on local projects rather than coordinating their development with regional planning needs is an inefficient way to meet overall grid needs. Coordinated regional planning can ensure that local projects are synergistically designed alongside regional projects to minimize costs as well as land use and environmental impacts. As FERC noted when it established regional transmission planning, "a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity . . . there is a danger that separate transmission investments will work at cross purposes and possibly even hurt reliability."[11]

vi Many state legislatures, for instance, have exempted projects that are lower voltage or that consist of like-for-like asset replacements, which local projects often are, from receiving a state certificate of public convenience and necessity. For more information, see ***Exhibit 5: State-Level CPCN Review Authority by Voltage***.

vii For example, Greg Poulos with the Consumer Advocates of PJM States recently discovered that 31 FirstEnergy Supplemental projects arrived at PJM when they were already initiated, under construction, or completed, and filed a hotline complaint at FERC (available upon request).

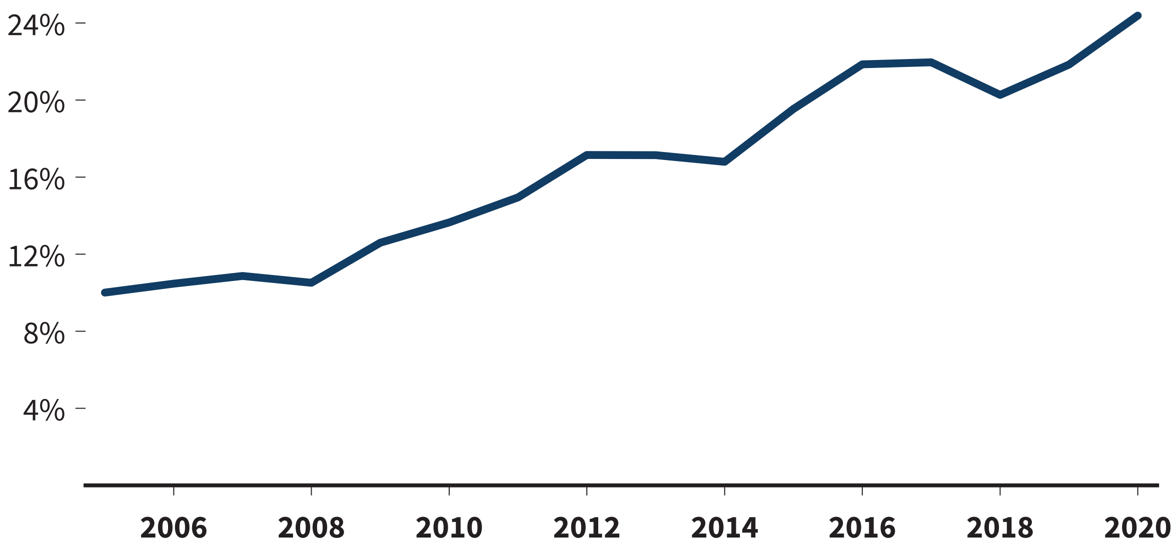
viii Regional projects, for instance, must be selected by regional planning entities to meet centrally and independently identified regional needs with robust stakeholder input. Projects are often selected via a competitive bidding process. Most regional projects are also required to receive state-level oversight in the form of a certificate of public convenience and necessity from the relevant PUC. Regional projects are also monitored by regional planning entities throughout construction, including for potential cost overruns.

Many Americans are increasingly struggling to pay their monthly electricity bills, underscoring the need for more proactive, least-cost regional planning rather than decentralized local investments. RMI found that in 2023, “nearly 70 million adults — one in every four — reported forgoing necessary expenses, such as for food or medicine, to pay their energy bills.”[12] Furthermore, the share of customer bills represented by transmission and distribution costs has been increasing steadily, from 10% in 2005 to 24% in 2020 (see Exhibit 2).[13] To achieve affordability through the clean energy transition, it will be essential for planners and regulators to ensure that ratepayer money is spent efficiently.

Relying heavily on local projects rather than coordinating their development with regional planning needs is an inefficient way to meet overall grid needs.

Exhibit 2

Portion of Residential Bill Spending on Transmission and Distribution



RMI Graphic. Source: RMI Utility Transition Hub

To better understand the impacts of the regulatory gap and identify reforms on the regional, federal, and state levels that could address it, we interviewed state PUC commissioners and staff, consumer advocates, and legal experts across a geographically diverse set of 18 states. We also reviewed relevant FERC filings and related evidence.[14,ix] The recommendations we present in the remainder of this report leverage the findings from our research.

ix This review focused on FERC Docket No. AD22-8 on Transmission Planning and Cost Management. It included the technical conference held by FERC on October 6, 2022, the pre- and post-technical conference comments filed by over 80 organizations, and the related meeting of the Joint Federal-State Task Force on Electric Transmission held by FERC and the National Association of Regulatory Utility Commissioners on November 15, 2022.

This report is structured as follows. To provide context for understanding the regulatory gap, we first outline the transmission planning landscape in the United States, including what oversight is currently performed on the regional, federal, and state levels (particularly with respect to local projects). Next, we utilize recent transmission spending data to illustrate the extent and scope of the gap. Finally, we describe potential interventions at the regional, federal, and state levels that could help address the regulatory gap.

Transmission Planning and Ratemaking in the United States

Electric transmission planning is a complex affair in the United States. It varies not only by state and region but also by the nature of the project. Understanding the regulatory gap requires a basic understanding of these planning processes and the actors involved, so we provide a high-level overview of key aspects of the system before diving into the findings from our research.

Transmission consists of the high-voltage wires, as well as the necessary supporting infrastructure (e.g., poles, transformers), needed to move electricity from where it is produced to where it will be used. Most users do not take power directly from the transmission system but instead from the lower-voltage distribution system. In the United States, transmission generally refers to lines above 69 kilovolts (kV) and distribution to lines that carry lower voltages.

Federal Ratemaking Authority

The transmission business is rate regulated as a public utility because electricity transmission has the characteristics of a natural monopoly.[x] In general, FERC regulates transmission rates,[15] whereas distribution rates are under the jurisdiction of the states.[xi] Typically, PUCs simply pass through FERC-approved transmission charges to customers via retail transmission charges. Once FERC has approved a rate, interested parties, including state regulators, do not have the authority to seek modifications to the rate without appealing it at FERC through a formal review process or filing a formal complaint.

Utilities have two options for setting transmission charges at FERC: **stated rates** and **formula rates**. For both options, FERC is responsible for setting the allowed rate of return that the utility can earn on its investments. Under the stated rate approach, the utility presents all anticipated investments and expenses, and FERC then reviews these in detail and determines which of its incurred costs the utility will be permitted to recover via rates. Once a stated rate goes into effect, it remains in place without modification until the next time rates are reset. Though stated rates enable a detailed review of transmission expenditures, setting them is time- and effort-intensive.

FERC also offers utilities the formula rate option. Under this option, a utility files a formula for calculating its transmission costs with FERC. Once FERC approves the formula, the inputs used in the formula are updated annually, but the formula itself is not revisited by FERC unless the utility requests it or a formal challenge to it is filed by another party. Under FERC's formula rate protocol, state regulators, consumer advocates, and ratepayers can intervene to request more information about the annual inputs or to bring forward formal challenges.

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x A natural monopoly is an industry subject to large economies of scale that make it difficult for more than one firm to successfully compete. Building transmission infrastructure is very capital intensive, and once one set of wires is in place, it becomes very difficult for other potential transmission operators to enter the market.

xi Non-FERC-jurisdictional regions include US states and territories whose grids are not connected to other states or territories, such as Alaska, Hawaii, and most of Texas. For the purposes of this report, we focus on solutions relevant in FERC-jurisdictional areas. We also note that in some states with vertically integrated utilities (i.e., utilities own both generation and transmission/distribution assets), state PUCs exercise some ratemaking authority over transmission. How states exercise this authority varies. For the purposes of this report, we focus on ratemaking reforms that FERC can take and do not fully explore state-level ratemaking reforms.

FERC introduced the formula rate option to incentivize transmission expansion by reducing the burden of the rate-setting process. This was an important goal when FERC first adopted formula rates, and it is arguably even more critical today. Uptake of the formula rate option has been popular: as of 2019, 106 FERC-regulated utilities had formula rates, whereas only 31 used stated rates.[16] However, although formula rates can encourage transmission investment by streamlining the rate-setting process, they also have an important downside, which is that they tend to create weaker incentives to keep costs in check than the more traditional process of setting rates afresh every few years does.[xii]

Box 2

Components of a FERC Formula Rate

FERC formula rates are intended to enable the utility to recoup its cost of service (i.e., the cost it must incur to provide transmission service to its customers). The components of a formula rate include allowances for the utility's capital costs (including both the return of capital — i.e., depreciation expense — and return on capital), operating expenses, and taxes. Though every FERC-approved formula rate employs inputs specific to the utility, all have a common structure. This structure is shown below.[17]

Cost of Service = R + O&M + DE + OE + IT + OT − OR

R = return (rate of return × rate base)
O&M = operations and maintenance expense
DE = depreciation expense
OE = other expenses
IT = income taxes
OT = taxes other than income taxes
OR = other operating revenue

Additionally, FERC's formula rate process may not provide adequate oversight of utility spending decisions. One key shortcoming is that FERC assumes that all investments that go into the formula rate are prudent unless proven otherwise. This is a different standard than that used in state regulatory proceedings, which typically require the utility to demonstrate an investment was prudent before it can recover those costs from customers. In contrast, FERC's formula rate prudence presumption places the burden on other parties to demonstrate why an investment is likely not prudent before FERC will consider disallowing it. However, other parties (for example, state regulators and consumer advocates) often do not have access to the information they would need to make the case for additional review, as this information is held by utilities and not routinely disclosed. Parties' challenges are limited by the terms of the formula rate, and in a formula rate update proceeding, there is no opportunity for other parties to file evidence. Typically, other parties can challenge only whether the utility followed its approved formula. As various industrial customer organizations

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xii Formula rates tend to create weaker cost-containment incentives than traditional rate cases (for example, those used to set FERC's stated rates) because whenever the utility's costs rise, the formula rate updates the company's revenue allowance to match. In contrast, in a traditional rate case, the utility would have to submit its new costs to regulatory scrutiny in order to receive a rate increase, which increases the risk that the regulator may deem some of those costs imprudent and disallow them for recovery. As a result, formula rates generally decrease the utility's incentive to manage its costs carefully. In cases where the benefits of formula rates are compelling, such as for the purpose of encouraging swift transmission expansion, FERC can consider taking steps to strengthen the utility's incentive to spend cost-efficiently. We describe some recommended actions that FERC could take in the ***Federal Reforms*** section of this report.

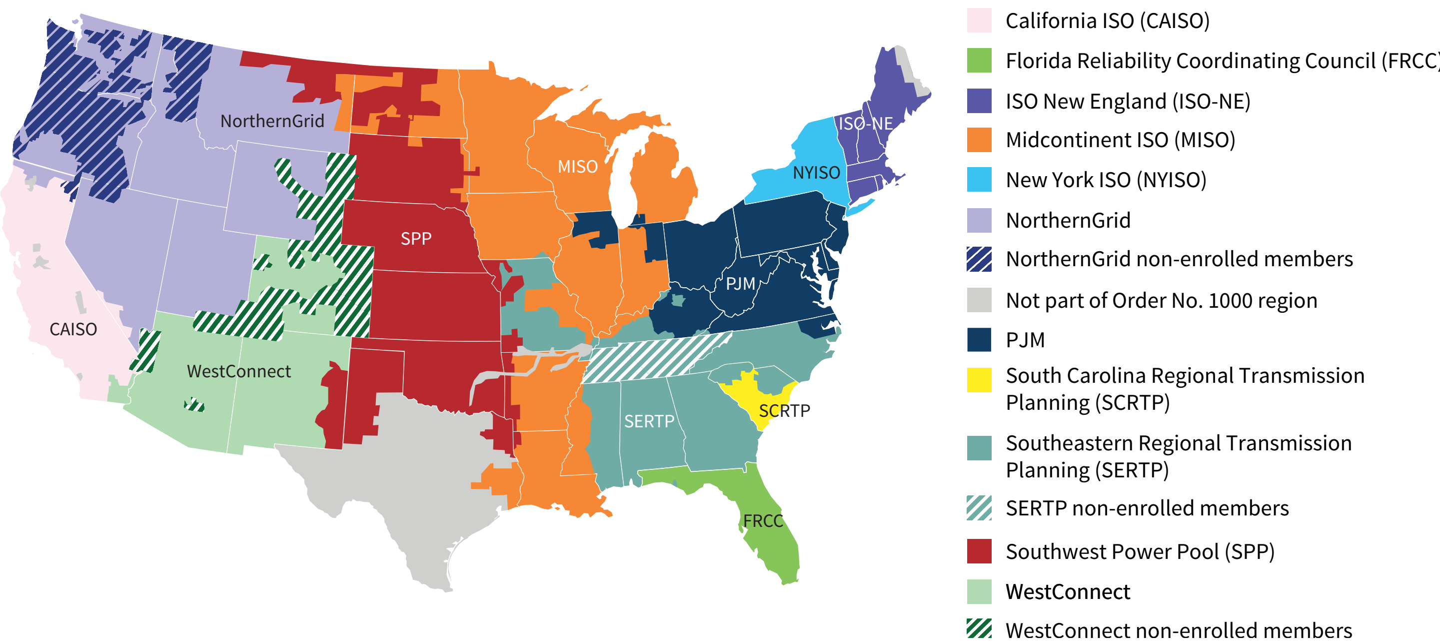
wrote in comments to FERC in 2023 as part of Docket No. AD22-8, formula rates "continue to allow a near-automatic transmission cost recovery with no meaningful check on additions to transmission rate base."[18]

Regional Planning

In addition to regulating the rates that utilities can charge, FERC also regulates the planning procedures for most of the US grid. Regional planning entities, approved by FERC in 2011 through Order No. 1000, are responsible for implementing these planning procedures. These entities are intended to leverage input from utilities, states, and other stakeholders to identify transmission investments that meet regional needs and deliver regional benefits, such as ensuring system reliability, reducing costs for customers, and implementing state and federal public policies. In much of the continental United States, the role of regional planning entity is filled by a regional transmission organization (RTO) or independent system operator (ISO), with exceptions in the western and southeastern parts of the country.[xiii] Exhibit 3 shows the Order No. 1000 regional planning entities in the continental United States.

Exhibit 3 **FERC Order No. 1000 Regional Planning Entities in the United States**

Color areas are intended to approximate the scope and location of the transmission region but are for **illustrative purposes only**.



Note: Cross-hatching indicates utilities that are not FERC jurisdictional but have chosen to participate in Order No. 1000 regional planning processes (e.g., power marketing administrations, such as Bonneville Power Administration). Gray areas indicate areas that are not in FERC's jurisdiction and do not participate in Order No. 1000 regional planning processes. These include the Electricity Reliability Council of Texas (ERCOT) as well as municipally owned utilities and cooperatives. Hawaii and Alaska, which are not shown, are also not FERC jurisdictional and do not participate in Order No. 1000 regional planning. At the time of publication, SERTP and SCRTP had announced that they were planning on merging, but such a merger had not yet occurred, so the two regions are left separate in this exhibit.

RMI Graphic. Source: FERC

xiii In Order Nos. 888 and 2000, FERC outlined the parameters it would use to review utility applications to create ISOs and RTOs. FERC then approved ISO and RTO proposals in subsequent orders submitted by interested utilities.

In a region with an RTO or ISO, that entity is responsible for independently operating the transmission system and ensuring open access to it for all qualified parties. In a region without an RTO or ISO, the responsibility of operating the grid is divided among several utilities in the region and the regional planning entity serves as a forum for coordination among individual utility planning efforts.[19] These entities perform regional planning on different timescales.[xiv]

How Local Projects Are Currently Considered in Regional Planning

FERC Order No. 1000 allows for the separate categorization and treatment of local transmission projects. As noted previously, local projects are projects planned and built by a single utility to meet needs within that utility's footprint.[xv] These needs may include replacing aging infrastructure (this is typically called an asset management project), interconnecting new loads, enhancing operational flexibility, and ensuring that local reliability standards are met. Local projects are generally not required to undergo a thorough review at the regional level — and in certain instances, FERC has explicitly exempted them from regional planning processes.[xvi]

Local projects are generally not required to undergo a thorough review at the regional level — and in certain instances, FERC has explicitly exempted them from regional planning processes.

As a result, local projects are typically included in regional planning as an assumed input, such that regional projects are only identified to meet any remaining needs.[xvii] Unfortunately, this is not an efficient approach to planning because an uncoordinated set of local investments is likely to cost more than a strategic approach at the regional level. For example, the PJM Interconnection (PJM) has estimated that regional planning efficiencies already yield $300 million in annual benefits to ratepayers "by considering the region as a whole, rather than by individual states or separate transmission-owner territories, in determining transmission needs."[20] In Tranche 1 of its Long-Range Transmission Planning process, approved in 2022, the Midcontinent Independent System Operator (MISO) estimated that efficient regional planning of projects could save up to $1.9 billion in avoided transmission investment over a 40-year period.[21] These savings could be even greater if regions were to fully integrate local projects into their regional planning processes by allowing for better identification of transmission needs and additional planning efficiencies.

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xiv Recently in Order No. 1920, FERC required entities to begin conducting long-term planning (looking 20 years out) in addition to existing shorter-term regional planning processes. We discuss Order No. 1920 in more detail in the ***How FERC Order No. 1920 Will Change the Consideration of Local Projects in Regional Planning*** section of this report.

xv Specifically, the word *footprint* refers to a transmission zone. Though a transmission zone is specific to one utility, it can span more than one state for a multistate utility (e.g., PacifiCorp). This is distinct from the service territories that PUCs use to regulate utility distribution service at the state level.

xvi For instance, in Order No. 890, FERC explicitly exempted asset management projects from regional planning, an exemption that has been maintained in subsequent FERC orders.

xvii For example, the MISO Transmission Owners noted in comments to FERC in Docket No. AD22-8-000 that asset management projects are "considered bottom-up projects for purposes of analysis under MTEP" (MISO Transmission Expansion Plan, MISO's annual regional transmission plan), (Docket No. AD22-8-000, "Comments of the MISO Transmission Owners," March 23, 2023, **https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230323-5211&optimized=false**).

Although some regional planning entities theoretically review local projects to assess whether they could be replaced by more regionally efficient solutions, this may not happen much in practice. For instance, in comments filed at FERC, the Iowa consumer advocate noted that in MISO, "local projects are not considered for more efficient and cost-effective transmission solutions."[22] As another example, in PJM it is up to each utility to identify whether local needs can be met regionally.[23] However, as state regulators in PJM have noted in comments filed at FERC, utilities have a disincentive to do this because regional planning could expose them to competition.[24] In non-RTO regions, planning is almost entirely conducted at the local level by the utilities, with the regional planning entity not independently reviewing projects for maximum efficiency.[xviii]

Concerningly, state decision makers may trust regional planning entities to do a comprehensive review of local projects, even though it is unclear to what extent each entity does this. For instance, Greg Poulos, commenting on behalf of the Consumer Advocates of PJM States, noted that many state regulators in PJM have "reduced staff or ceded transmission regulatory authority" under the belief that regional planning entities are providing sufficient oversight, even though this has been difficult to verify.[25]

> **"At the state level, regulatory bodies assume that the FERC-sanctioned regional planning process has adequately considered the most economic alternatives and proceed to approve the local projects the utilities present to them. The utilities then point to the state regulatory processes as comprehensive, holistic, and the rightful forum for transmission expansion."**
>
> — **Nick Guidi**, Southern Environmental Law Center, pre-FERC technical conference comments[26]

How FERC Order No. 1920 Will Change the Consideration of Local Projects in Regional Planning

Local transmission projects today often receive scant regulatory oversight. As already discussed, state regulators are limited in their ability to oversee the planning process — and they may also struggle to obtain basic levels of transparency from utilities concerning the need for projects, their projected costs, and the alternative options considered. Customers, consumer advocates, and other stakeholders who should be able to examine utility decisions in FERC proceedings can face even greater obstacles to obtaining the information they need to intervene effectively. FERC has recognized this problem and recently took action to increase transparency through Order No. 1920, which imposes a number of reforms to current regional transmission planning processes.[27]

One of the new requirements under Order No. 1920 is that utilities must hold a series of three meetings for each proposed local project detailing the assumptions, needs, and solutions. These meetings must be open to state regulators and other stakeholders, separated by at least 25 calendar days, and have meeting materials posted at least five calendar days in advance. However, this three-meeting requirement does not apply to asset management projects, which, as explained earlier, involve replacing an existing facility.

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xviii Non-RTO regions refer to the FERC-jurisdictional Order No. 1000 planning regions that do not have RTOs or ISOs.

FERC exempted these projects from regional planning in Order No. 890, issued in 2007.[xix] Given that asset management projects can make up a large component of local transmission spending,[xx] the asset management project carve-out will substantially limit Order No. 1920's effectiveness.

FERC's new three-meeting requirement is based on PJM's Attachment M-3 process.[28] Unfortunately, it is not clear how effective the M-3 process has actually been in improving transparency or the decisions that PJM utilities ultimately make. One limitation of the M-3 process is that although utilities are required to hold meetings, they are not required to respond to stakeholder comments or questions. This means they can decline to provide any explanation to concerns raised by stakeholders, and if they choose to respond, they can choose what information to include or omit. This greatly limits stakeholders' ability to understand utility planning decisions, much less influence them.[xxi] Order No. 1920 marginally improves this situation because it requires utilities to "respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate," but it stops short of requiring replies to all comments or questions.[29] FERC claims that "such a requirement could be too prescriptive in certain circumstances" and that "some responses may be unduly burdensome to the transmission provider."[30] We believe, however, that requiring utilities to address all stakeholder questions and comments is a small price to pay when put in the perspective of the total cost of transmission infrastructure. Absent a requirement to respond to all stakeholder inquiries, FERC's "meaningfully participate" standard is going to require significant oversight and enforcement by FERC or regional planning entities to ensure that answers provided by utilities are robust and useful to stakeholders.

Another aspect of PJM's M-3 process that has limited its effectiveness is that utilities can bring local projects to the process after construction has commenced or, in some extreme cases, even after it has been completed.[31] Naturally, this greatly limits the ability of stakeholders to influence utility planning decisions. Unfortunately, Order No. 1920 does not include any mention of the timing of projects with regards to local project review, raising the possibility that this shortcoming of the M-3 process will be replicated at a broader level.

A second requirement under Order No. 1920 is that regional planning entities engage more fully in **right-sizing.** Right-sizing, as illustrated in Exhibit 4, means considering whether a larger project could better meet both local and regional needs than the smaller project. It is a vital aspect of sound planning because often a single large project is able to more cost-effectively meet multiple needs than a series of individually planned small projects, while reducing total land use and environmental impacts.

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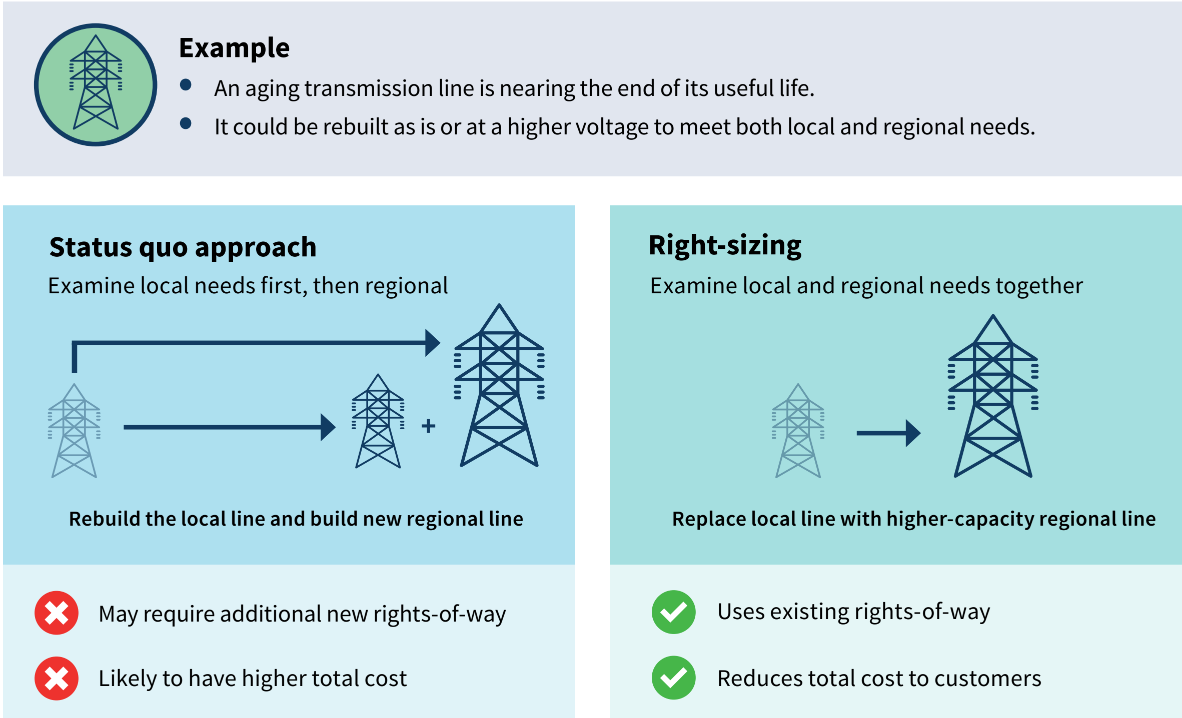
xix FERC justified this exemption with the reasoning that asset management projects do not involve expansion of the transmission grid, which FERC has historically considered to be a limit on its jurisdiction. We assert in this report that at a time of accelerating load growth and the clean energy transition, this exemption no longer makes sense and that asset management projects must be more fully incorporated into regional planning through regional-first planning to ensure that the most efficient and cost-effective planning is happening. Asset management projects, for instance, can be right-sized and thus be utilized to expand the transmission grid.

xx For example, in PJM, out of the $71.8 billion spent on Supplemental projects since 2005, 66% has gone to projects associated with the Equipment Material Condition, Performance, and Risk driver, compared to 16% on Customer Service, 13% on Operational Flexibility and Efficiency, 3% on Infrastructure Resilience, and 1% on Other (about 2% had no driver listed). For more information, see "Transmission Cost Planner," PJM Interconnection, accessed September 30, 2024, **https://tcplanner.pjm.com/tcplanner.**

xxi As Kent Chandler, the former chair of the Kentucky Public Service Commission, explained in filed comments, "Through the M-3 process, stakeholders can comment, ask questions, or propose solutions until they are blue in the face. However, the relevant utilities do not have to respond to comments, answer questions, or acknowledge proposed solutions. In this way, M-3 meetings provide no more of an opportunity to participate in local planning than if stakeholders instead chose to scream their comments, questions, and solutions into a cosmic void" (Docket No. AD22-8-000, "Pre-Conference Comments of Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler," September 16, 2022, **https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220916-5215&optimized=false).**

Exhibit 4 How Right-Sizing Works



RMI Graphic.

Under Order No. 1920's right-sizing provision, during each long-term regional planning cycle utilities will be required to submit "sufficiently early" a list of transmission assets that they anticipate replacing in kind over the next 10 years.[32,xxii] If the regional planning entity identifies that a right-sized replacement facility would meet the long-term regional need in a more efficient or cost-effective manner than a new-build solution, then that project must be considered by the regional planning entity for selection.[33] It is up to each planning region to set a voltage threshold above which this new right-sizing provision applies, although FERC sets an upper limit of 200 kV.

Order No. 1920's right-sizing provision applies only to long-term regional planning processes and not to short-term ones, which will limit its impact. Nevertheless, this provision represents an important step in the right direction, and regional planning entities could build on it. As we discuss in more detail in the *Implement Regional-First Planning* section of this report, regions could adopt (or FERC could require) right-sizing as a best practice for all time frames of planning, and thereby reduce the cost, land use, and environmental impacts of siting new transmission infrastructure.

A third requirement under Order No. 1920 is the inclusion of alternative transmission technologies, including several grid-enhancing technologies (GETs) and advanced conductors, in regional planning for

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xxii FERC defines an in-kind replacement as one that "would result in no more than an incidental increase in capacity over the existing transmission facility" and "located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility" (Order No. 1920, p. 1169 at 1678). Right-sizing would increase the capacity of the facility, but it would still be located in the same general route as and/or use the existing rights-of-way. This requirement can include asset management projects.

all timescales (i.e., short and long term).[xxiii] Research has shown these technologies can save vast amounts of money by enabling grid operators to make more efficient use of transmission infrastructure, yet they are greatly underutilized in the United States.[34] A key reason these technologies are not being fully considered or deployed on the US grid is the misalignment between the financial incentives of utilities (who are able to earn a return on every dollar they invest in infrastructure) and the interests of customers (who ultimately must pay for that infrastructure).[xxiv] FERC's requirement, if fully implemented in planning regions, has the potential to accelerate deployment of these technologies.

More remains to be done to reform local planning, even after Order No. 1920.

When considered together, the three key requirements in Order No. 1920 detailed above that most directly relate to local transmission — the three-meeting requirement, the right-sizing consideration, and the alternative transmission technology consideration — will significantly improve opportunities for synergistic transmission planning and regulatory oversight. However, these requirements will not close the regulatory gap. More remains to be done to reform local planning, even after Order No. 1920. As we explore further in this report, there are additional solutions, such as fully linking regional and local planning and enhancing federal and state review processes, that could help ensure transmission projects across the United States are being planned in a maximally efficient and cost-effective manner.

State Regulatory Authority

On the state level, PUCs perform several regulatory functions with respect to transmission. Depending on the state, these may include:

1. Issuing a certificate of public convenience and necessity (CPCN) for each transmission project that is legislatively required to receive one;
2. Reviewing transmission as part of integrated resource plans (IRPs) where IRPs are required;
3. Approving retail rates to recover transmission costs from end-use customers; and
4. Engaging in regional planning processes.

Even in states where the PUC performs all four of these functions, the degree to which they result in meaningful oversight of transmission projects varies. As Southeast Public Interest Groups described in filed comments about the first three functions, "these three layers of review do not fit together seamlessly, such that many transmission facilities slip through the cracks and do not receive an affirmative designation as a prudent investment worthy of cost recovery."[35] We describe each of these functions in greater detail in the following sections.

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xxiii GETs are a suite of technologies that can help extract more capacity from the grid for less money, including dynamic line ratings, topology optimization, and advanced power flow control. Advanced conductors are materials that can enhance the carrying capacity of power lines. For more information on these technologies, please refer to Russell Mendell, Mathias Einberger, and Katie Siegner, "FERC Could Slash Inflation and Double Renewables with These Grid Upgrades," RMI, July 7, 2022, **https://rmi.org/ferc-could-slash-inflation-and-double-renewables-grid-upgrades/**.

xxiv For more details, see Carina Rosenbach et al., *The Nuts and Bolts of Performance Based Regulation, RMI, 2024,* **https://rmi.org/insight/the-nuts-and-bolts-of-performance-based-regulation/**.

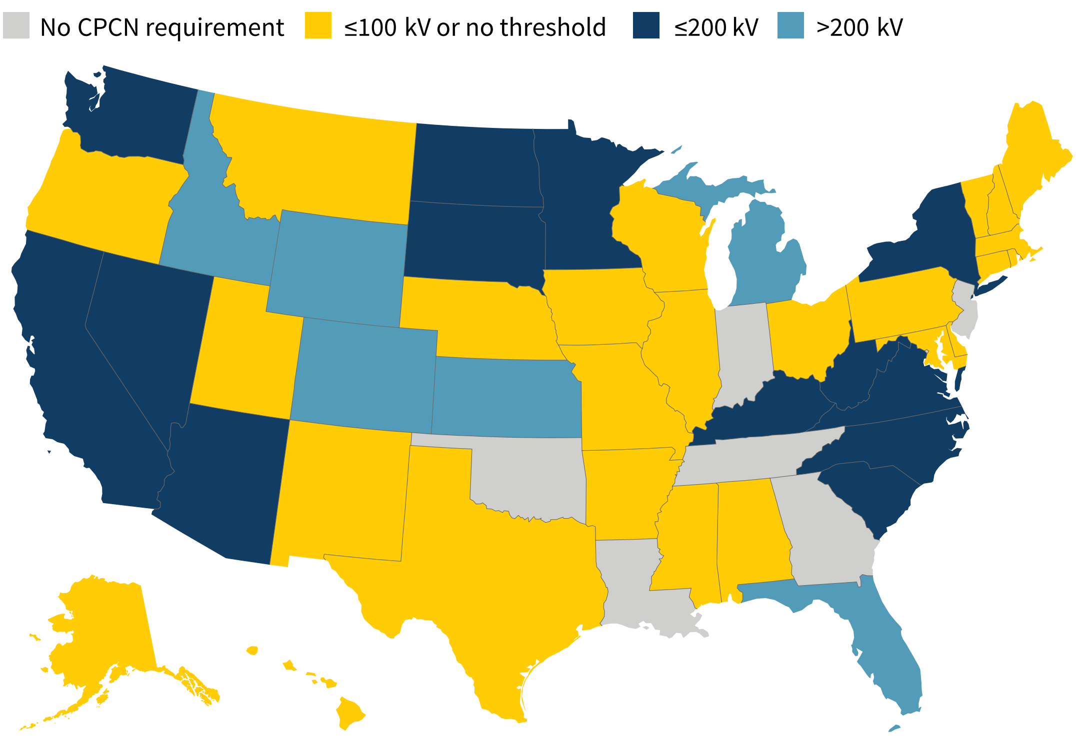
Certificate of Public Convenience and Necessity

In most states, transmission projects are required to receive a CPCN, which is essentially a permit from the PUC or other entity for a project to be built.[xxv] CPCNs frequently focus on issues pertaining to the siting of a line, with the PUC's ability to consider project prudence and cost potentially limited by CPCN scope. Even if a CPCN includes consideration of prudence or cost, the process is designed to focus on a single transmission project rather than the more holistic picture of all projects in a planning cycle. This limits regulators' ability to utilize the CPCN as a way to ensure proactive planning is happening.

As shown in Exhibit 5, state CPCN requirements vary substantially. Six states do not require a state-level CPCN,[xxvi] and many others do not require a CPCN for projects below a certain voltage threshold. Where CPCNs are not required for lower-voltage projects, this can substantially limit the PUC's ability to review local transmission projects. It is also common for states to not require a CPCN for projects that are identified as replacements of existing assets. This further exempts many local projects from being reviewed for a CPCN.

Exhibit 5 State-Level CPCN Review Authority by Voltage

Several states have set voltage thresholds below which transmission assets do not need to receive a CPCN.



RMI Graphic. Source: National Association of Regulatory Utility Commissioners; Joshua C. Macey and Elias van Emmerick, "Towards a Greater Federal Role in Transmission Planning," *Harvard Environmental Law Review 49* (forthcoming 2025)

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xxv In some states, another entity such as a siting board issues the CPCN instead of the state PUC (William H. Smith Jr., *Mini Guide on Transmission Siting: State Agency Decision Making,* Figure 1, National Council on Electricity Policy, December 2021, https://pubs.naruc.org/pub/C1FA4F15-1866-DAAC-99FB-F832DD7ECFF0).

xxvi Some of these states handle siting at the county or another governance level (Smith, *Mini Guide on Transmission Siting,* Figure 1, December 2021).

Given the variation in CPCN review authority and its emphasis on siting rather than prudence or cost, it is generally not an effective way for PUCs to ensure efficient investment. This is widely recognized by state regulators and advocates. For instance, Chair Phil Bartlett of the Maine PUC noted in comments filed at FERC that the CPCN is "an isolated evaluation of a single project rather than a more comprehensive assessment of transmission investments by the utility or for the region as a whole."[36] Southeast Public Interest Groups similarly noted that "proposed transmission investments arrive at the state commissions fully baked. Opposing utility-selected transmission facilities during a CPCN proceeding rarely, if ever, succeeds."[37] James McLawhorn, who is on the Public Staff at the North Carolina PUC, shared at the FERC 2022 technical conference that when a project falls below 161 kV (the state's voltage threshold for CPCN review), staff "find out about it . . . when it shows up in rates." When a project does need a CPCN, utilities often assert that failing to issue the CPCN would threaten grid reliability — as McLawhorn explained, they effectively argue "we're out of time and we need you to move forward with it."[38]

Given the variation in CPCN review authority and its emphasis on siting rather than prudence or cost, it is generally not an effective way for PUCs to ensure efficient investment.

For all these reasons, a CPCN is not a substitute for comprehensive oversight of transmission planning. If a PUC is expected to ensure that transmission investments are prudent, its role must start earlier and extend to the full suite of projects under consideration. The PUC should perform this role in partnership with regional planning entities.

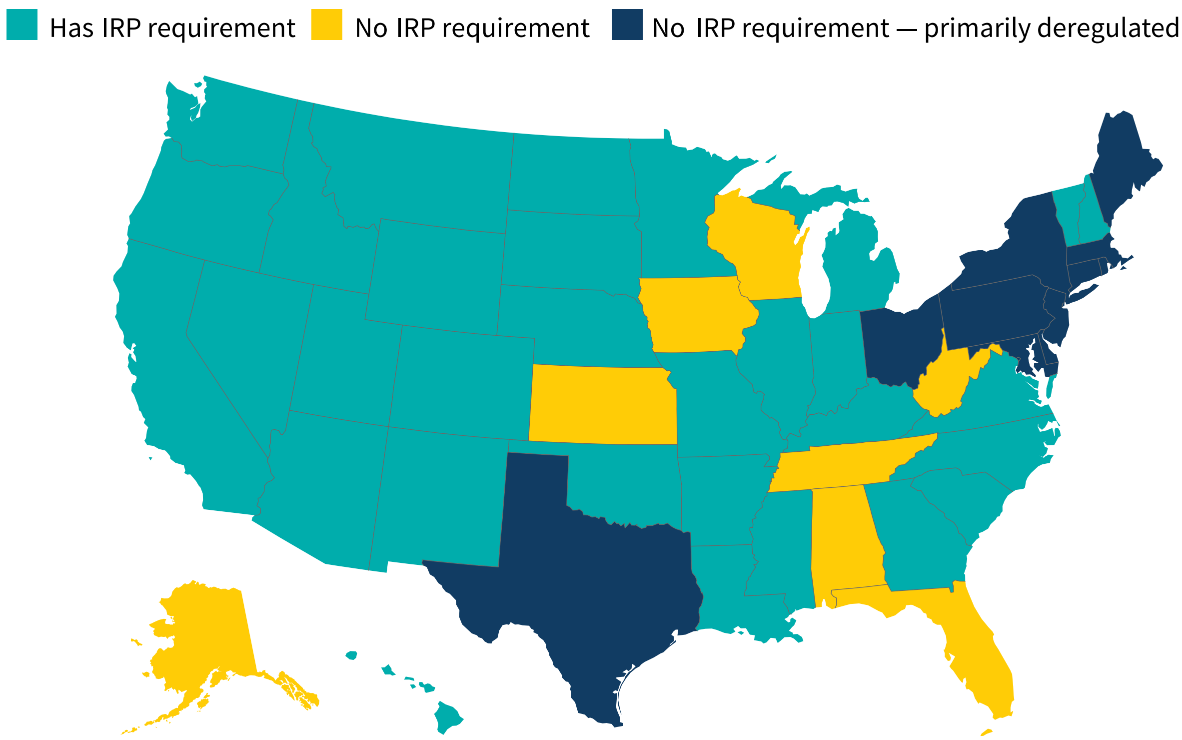
Integrated Resource Planning

IRPs are resource-planning exercises that require utilities to develop portfolios of future investments sufficient to meet projected load growth and state policy goals over a set time horizon (often 10 to 30 years). In many states, IRPs are also a critical venue for stakeholders to provide input into utility assumptions about future demand and supply options. As shown in Exhibit 6, most states with vertically integrated utilities — in which the generation function is subject to PUC rate regulation — have some type of an IRP requirement.

IRP rules and guidelines vary state to state and impact what is included in plans, how planning is done, and how much influence plans have on decision-making and investments. Similarly, the role of the commission varies: some states only require the utility to file an IRP but do not require the PUC to approve it.[xxvii] Today, most IRPs focus on generation planning, and transmission, if included at all, is treated as a secondary consideration.

xxvii State IRP requirements vary in many ways. For more details about the use of IRPs by US states, see Mark Dyson, Lauren Shwisberg, and Katerina Stephan, *Reimagining Resource Planning, RMI, 2023,* **https://rmi.org/insight/reimagining-resource-planning/**.

Exhibit 6 IRP Requirements by US State



RMI Graphic. Source: US Environmental Protection Agency, *State Energy and Environment Guide to Action: Resource Planning and Procurement*, Figure 2; RMI analysis of EIA-860M to add distinction for primarily deregulated states

IRPs are not designed to be the primary venue for effectively coordinating or planning at a regional level. These plans are often utility-specific, and state PUCs do not have authority over how FERC-jurisdictional projects are planned or how FERC sets rates to recover their costs. However, the IRP process can still be useful in advancing smart transmission planning and investment. Commissions can require utilities to identify and consider different alternatives to meeting demand through IRPs, and the planning process can provide greater transparency into the utility's plans for transmission and the potential costs associated with various options. To realize these benefits, transmission, both local and regional, must be incorporated into the IRP process, and the IRP process itself must be well designed and implemented effectively.[xxviii]

State-Level Rate Cases

PUCs hold periodic rate cases for each of the utilities they regulate in which they review utility expenditures for prudence, approve or deny costs for recovery, and set rates to recover those costs from the utility's customers. However, for most transmission expenditures, FERC determines the cost the utility is eligible to recover from customers, not the PUC. Once FERC sets the amount a utility is eligible to recover, the PUC reviews and approves the retail rates that recover those costs from end-use customers within that utility's

xxviii For more information on best practices for modern IRP development, please see "Task Force on Comprehensive Electricity Planning," National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, accessed September 18, 2024, **https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/home/.**

service territory. The PUC is not allowed to change the FERC-approved amount to be recovered. As a result, PUCs commonly employ a rate rider to pass those costs through to customers with little additional scrutiny.

Engaging in Regional Planning

PUCs, as well as state consumer advocates and other state-level stakeholders, can engage in the stakeholder processes facilitated by regional planning entities. However, their ability to meaningfully influence the planning process varies by region.

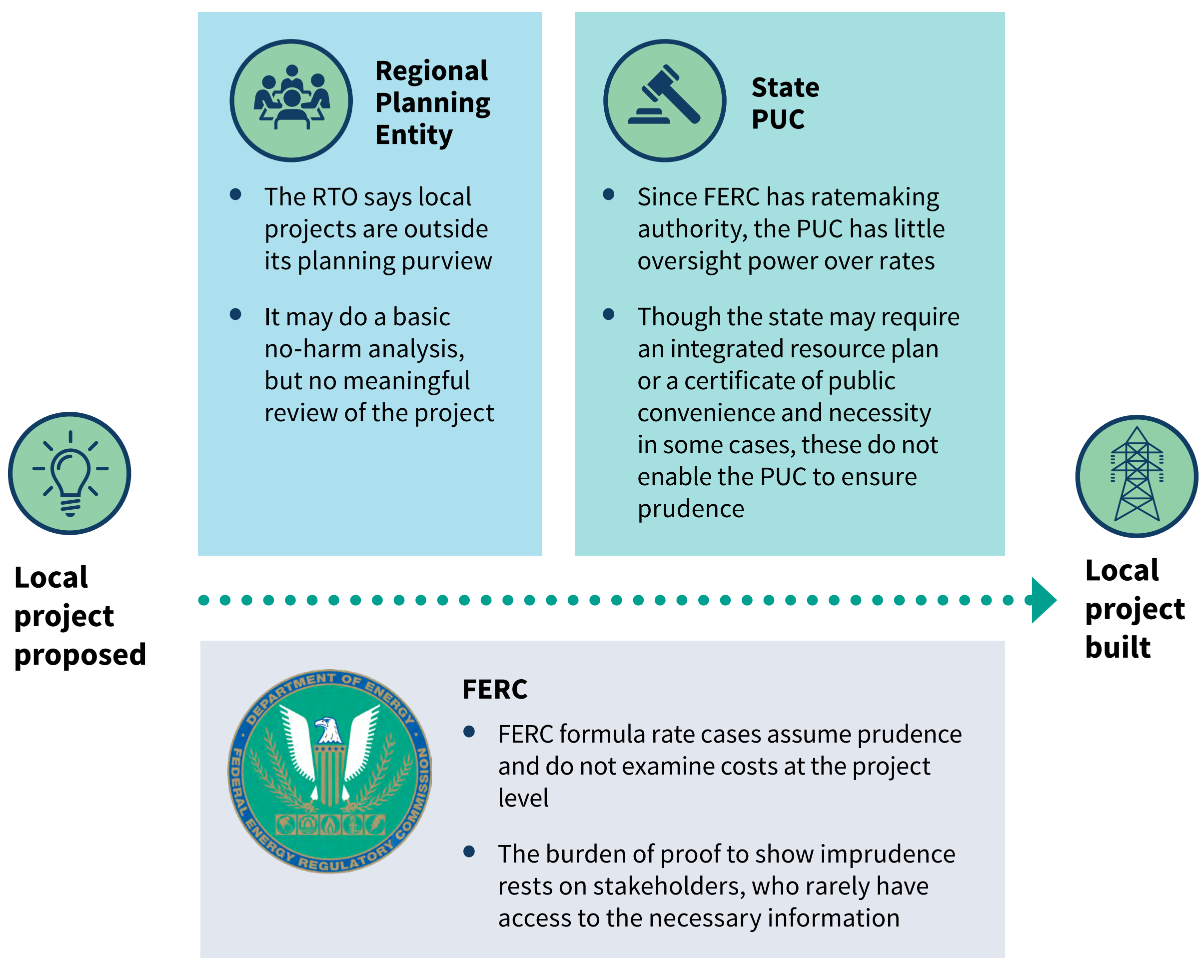
Some RTO and ISO governance structures, for instance, can limit state decision makers' ability to influence the actual decision-making that takes place. These governance structures are complex and widely studied.[39] However, governance reforms are beyond the scope of this report.

> **"In practice, state control is often an illusion. Even in vertically integrated states, state commissions minimally exert input or direction into utility transmission planning. Transmission is rarely integrated into utility integrated resource plans; many states removed transmission when they modernized IRP rules. Even where state commissions pre-approve transmission investments, regulators' insight into screening criteria for needs and alternatives is murky at best. Said more plainly, state commissions are often not presented with the most economic choices, which are often interstate projects that extend beyond their jurisdictions."**
>
> — **Devin Hartman**, director, R Street Institute
> and **Kent Chandler**, former chair, Kentucky Public Service Commission[40]

Consequences of the Regulatory Gap

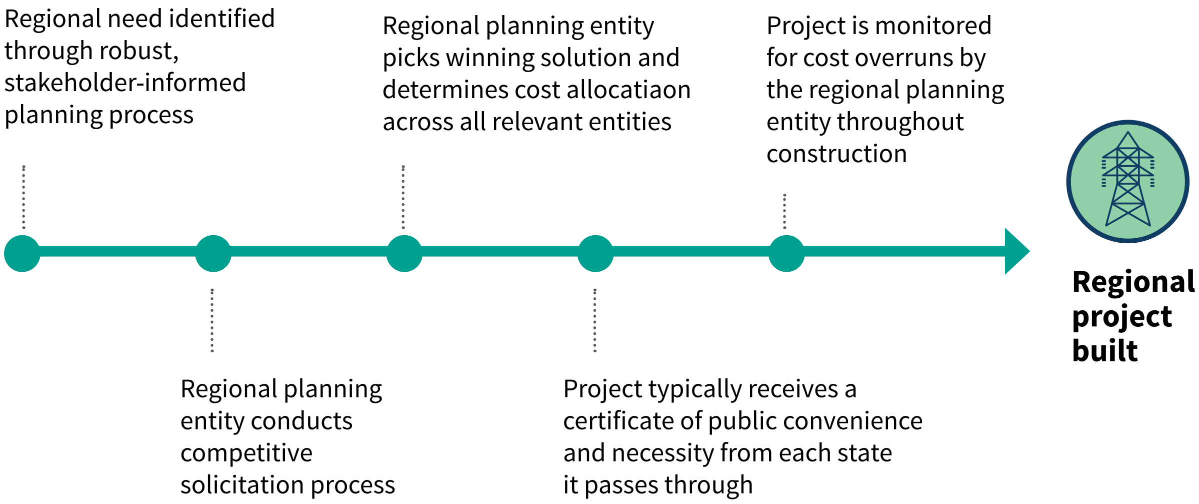
In the preceding discussion, we showed that federal, regional, and state entities do not adequately review local transmission projects — there is a **regulatory gap**. Exhibit 7 summarizes the local transmission regulatory gap and Exhibit 8 compares it to the more thorough review used for regional projects. While FERC Order No. 1920's new meetings, right-sizing, and alternative transmission technologies requirements may lead to incremental improvements, these are partial solutions that will not fully closethe regulatory gap.

Exhibit 7 The Regulatory Gap for Local Transmission Projects



RMI Graphic.

Exhibit 8 **Regional Transmission Project Review Process**



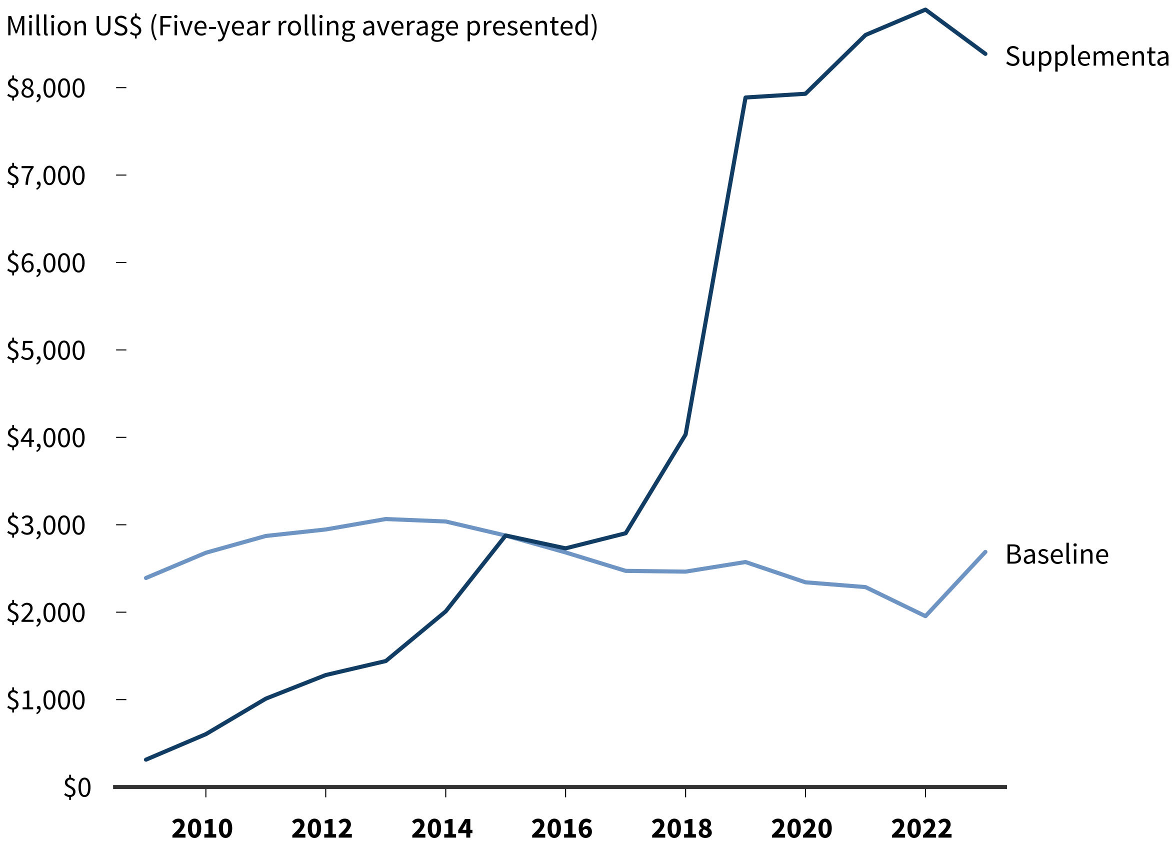
RMI Graphic.

> **Transmission spending patterns reveal real-world consequences on the types of projects utilities are building and the impacts on customer bills.**

The regulatory gap is not just a theoretical problem. Transmission spending patterns reveal real-world consequences on the types of projects utilities are building and the impacts on customer bills.

In RTO regions, utilities have shifted spending dramatically toward local projects. In PJM, spending on local projects (which PJM calls Supplemental projects) increased 26-fold from 2009 to 2023, as illustrated in Exhibit 9, while spending on regional projects (which PJM calls Baseline projects) stayed relatively flat.[41] In ISO New England (ISO-NE), spending on local projects (called asset condition projects) increased eightfold from 2016 to 2023.[42] The same story holds in the California ISO (CAISO) with local projects (called self-approved projects), where 63% of projects from 2018 to 2023 were self-approved projects not eligible for state or CAISO review.[43] In MISO, local projects (called Other projects) have increased from 54% of total spend in 2017 to 78% in 2022.[44]

Exhibit 9 PJM Transmission Spending

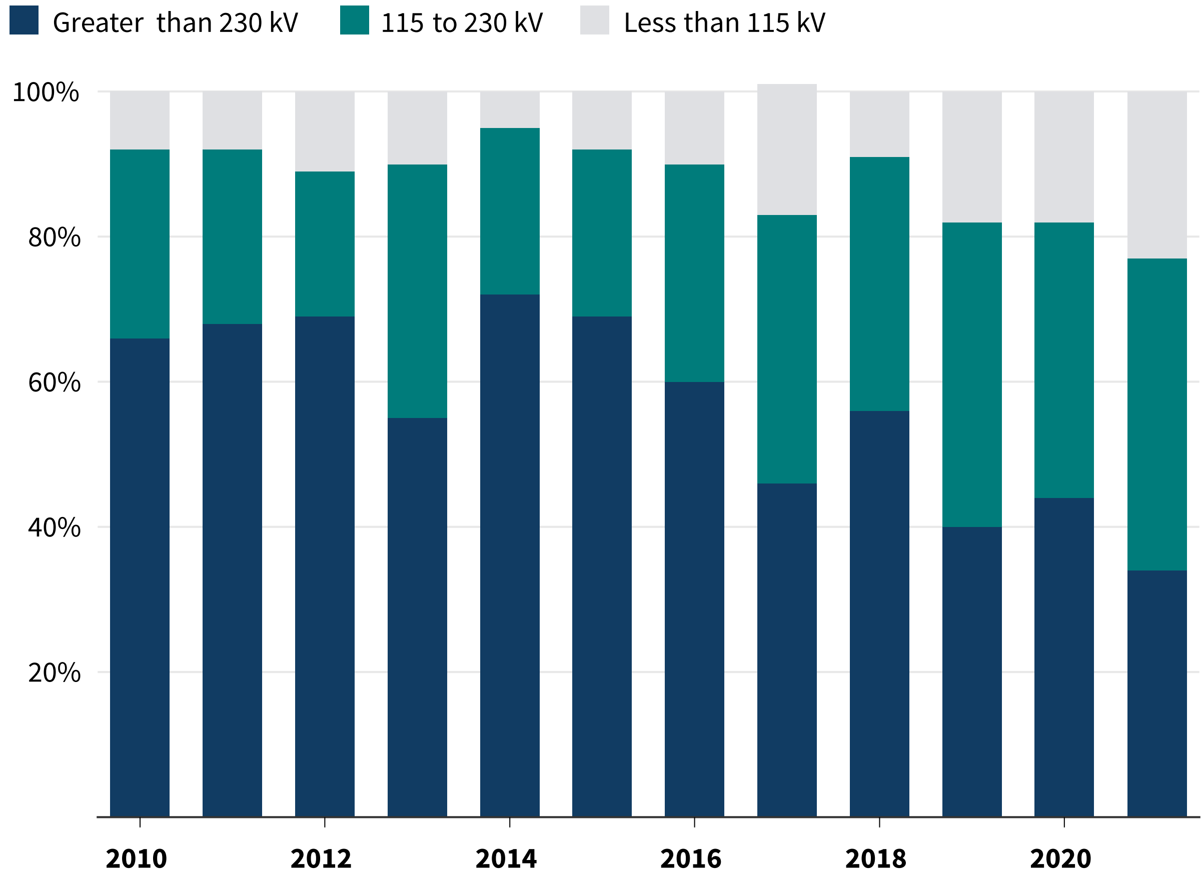


RMI Graphic. Source: PJM Interconnection

In non-RTO regions, limited data accessibility and the lack of effective regional planning entities make it difficult to evaluate specific spending trends. In these regions, utilities conduct transmission planning for only their service territories. Although there are a few select cases of planning across multiple utilities, not a single regional project has been planned and approved by non-RTO regional planning entities since FERC's Order No. 1000 created them in 2011.[45] Consequentially, these regions' transmission investments have consisted entirely of local projects.

Together, regional spending trends show a concerning nationwide trend: regional transmission investments have been falling while local transmission spending has risen. Since 2010, the percentage of spending on projects with voltages greater than 230 kV has been steadily declining, from a high of 72% in 2014 to just 34% in 2021, as illustrated in Exhibit 10.[46]

Exhibit 10 **Share of Total US Transmission Spending by Voltage**



RMI Graphic. Source: FERC

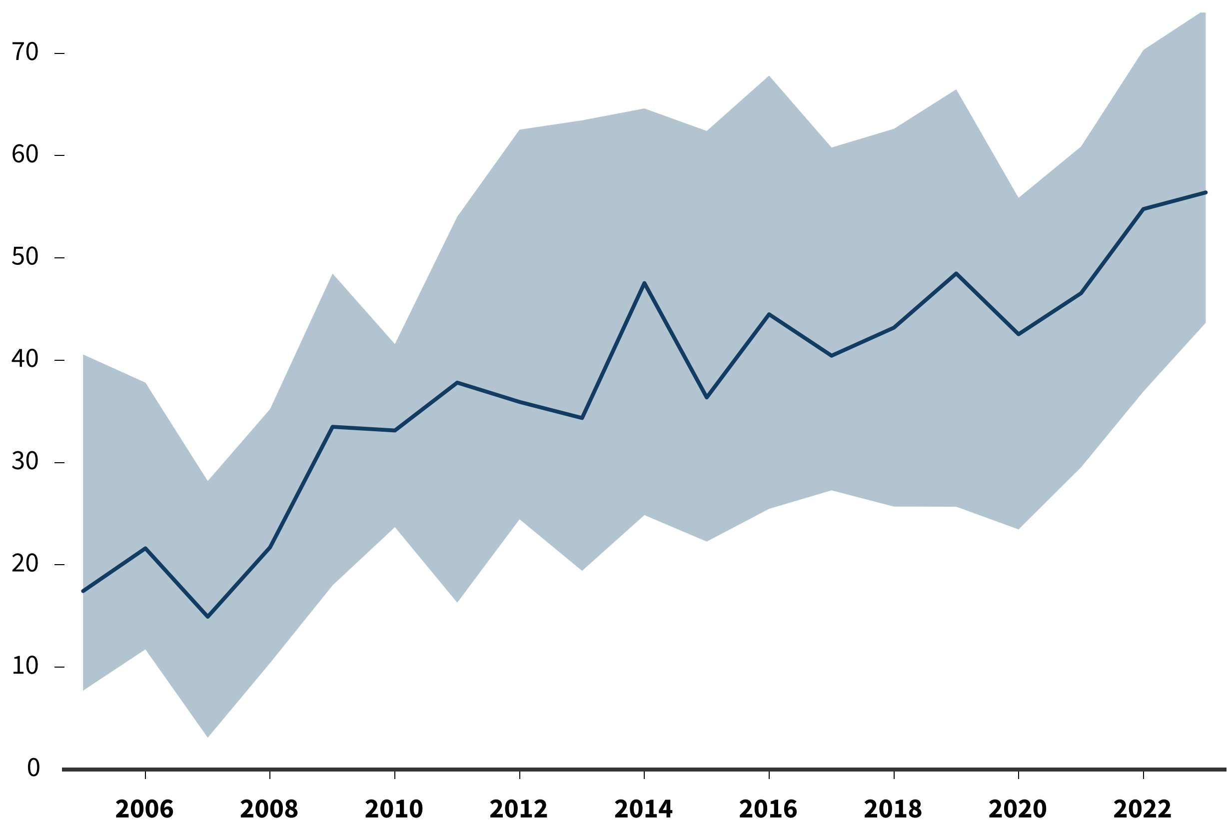
With spending concentrated on smaller local projects, the miles of transmission built have declined. Grid Strategies found that while transmission spending hit an all-time high in 2023, the United States built only "20% as much new transmission [mileage-wise] in the 2020s as it did in the first half of the 2010s." The analysis also found that only 55 miles of new high-voltage transmission were added in 2023, compared to a record 4,000 miles in 2013.[47] Similarly, the Brattle Group found that 90% of recent transmission spending has been on lower-voltage reliability upgrades, with 50% of all spending going toward local projects.[48]

Though other factors could partly account for the growth in local transmission spending — such as the need to replace aging infrastructure — the strong trends we've identified suggest a shift in how utilities make transmission spending decisions. The regulatory gap is a likely suspect because it enables utilities to invest more money in local transmission projects without having to justify their investment decisions to regulators. Further, utilities can usually pursue local projects without competition, in contrast to many regional projects that Order No. 1000 requires be open to competitive bidding.

If the spending trend toward local projects continues, there is a risk that as utilities increase spending on local projects, those costs could crowd out investments in regional transmission that have the potential to also bring system-wide cost savings. Regulators and consumer advocates are understandably hesitant to spend more on regional infrastructure when local transmission costs are already driving up bills.

However, the problem extends beyond the costs of just transmission itself. If utilities do not proactively build enough regional transmission infrastructure, customers will miss out on the benefits of regional transmission. Cheap renewable generation resources in remote regions will struggle to interconnect, driving up both costs and carbon emissions, as is already evident from the yearslong interconnection queue delays across the United States, shown in Exhibit 11. US grid regions will also be unable to efficiently share generation capacity, leading to overbuilt generation capacity and greater costs. In addition, inefficient grid architecture could prevent grid operators from redirecting power when severe weather hits, threatening reliability and imposing economic costs on affected areas. Finally, a lack of regional transmission can also increase transmission congestion costs. As shown in Exhibit 12, congestion costs in the United States have tripled in recent years, with our country's transmission network at capacity and struggling to expand efficiently.[49]

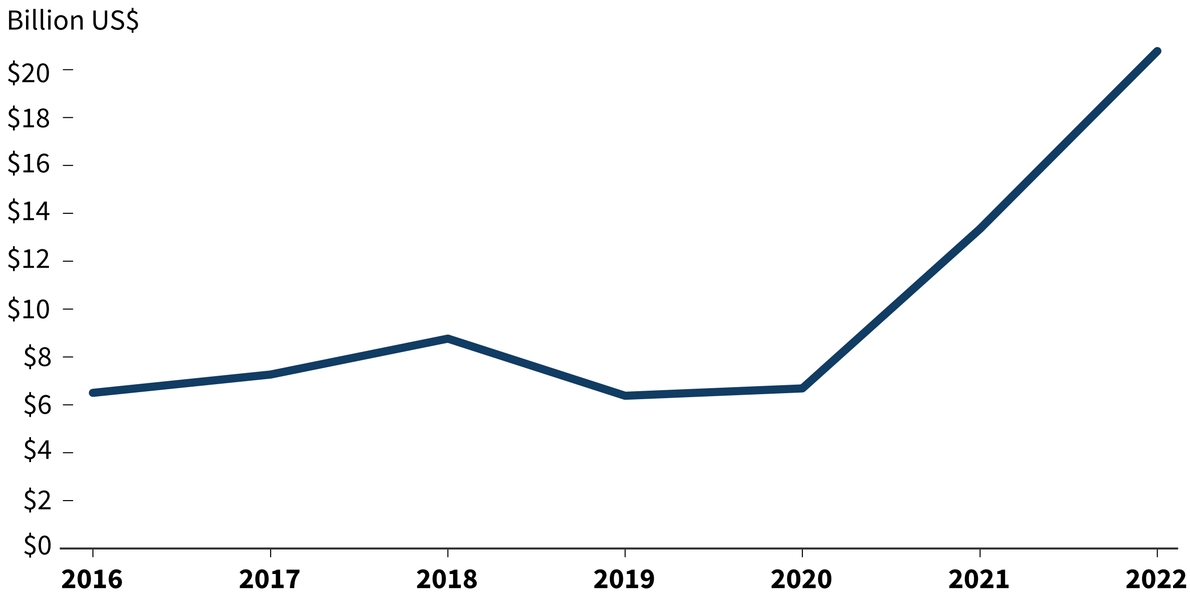
Exhibit 11 Months Interconnection Requests Spend in US Queues



Note: The data represents the time, in months, that projects have spent in interconnection queues in the US on average between 2005 and 2023, from submission of an interconnection request to commercial operation date. The line displays the median amount of time for projects that reached commercial operation date in that year, with the light blue range representing the 25th and 75th percentile bounds. Data is averaged across US grid regions.

RMI Graphic. Source: Lawrence Berkeley National Laboratory

Exhibit 12 Annual Congestion Costs for the US Grid



RMI Graphic. Source: Grid Strategies

Right-sized regional projects could help resolve many of these challenges — interconnection delays, increased congestion costs, sharing of generation capacity, and reliability during extreme weather events — while also reducing land use and environmental impacts. Ensuring well-planned and cost-effective transmission projects should therefore be a policy priority, and achieving this will require adequate, comprehensive regulatory review.

As one state regulator we interviewed explained, "I have a hard time believing that simply rebuilding the grid of 80 or 90 years ago will produce the right grid for 50 or 60 years from now, which is how long these facilities are going to last."

With 70% of transmission lines approaching the end of their lifespan,[50] this problem is urgent. Now is the time to ensure we do not just rebuild the grid of the past through local replacement projects but proactively build the grid of the future. As PJM has noted, "greenfield transmission-level voltage solutions may not always be the most cost-effective solution, given the practicalities of siting and building such facilities. Enhancements to existing sub-transmission level voltage facilities — e.g., 230 kV or lower — may indeed be the more cost-effective solution to achieve the same level of reliability."[51] The utility Xcel also recognized in filed comments that "in some situations, regional projects may be more cost-effective than local projects, in particular in the current environment where climate goals are driving a virtually wholesale replacement of existing generation resources with more dispersed and often more remote renewable resources."[52]

Unfortunately, the regulatory gap is a barrier to efficient regional planning. As one state regulator we interviewed explained, "I have a hard time believing that simply rebuilding the grid of 80 or 90 years ago will produce the right grid for 50 or 60 years from now, which is how long these facilities are going to last."

Box 3

Illustrating the Regulatory Gap: The X-178 Project

One recent example of the regulatory gap in action is the X-178 project, currently proposed by Eversource Energy in New Hampshire. First proposed in February 2024, the project involves a full rebuild of a 115 kV line, despite the fact that only 43 of the 594 structures of the line have been identified as high priorities for replacement and that many of the structures are younger than their estimated useful lives. The project is estimated to cost $385 million.[53]

New England state regulators, through the New England States Committee on Electricity (NESCOE), have submitted feedback on multiple instances to Eversource and ISO-NE. These regulators have cited the “lack of compelling evidence to support the scope of the project” and requested additional information from Eversource on the project and cost drivers. Eversource failed to provide the requested information, however. Despite the objections from stakeholders, Eversource is currently planning on proceeding with a full rebuild and it does not need to obtain any additional approvals from ISO-NE.[54] The project is also not required to receive a state-level CPCN, although New Hampshire’s Site Evaluation Committee (the entity responsible for issuing CPCNs for transmission projects) has discretionary authority to issue one. Local advocates have petitioned for this authority to be utilized.

In an August 1, 2024, letter to Eversource, NESCOE wrote that “Eversource’s disregard of requests for information that states believe would help assess proposals was troubling. . . . Eversource’s plan, despite broad state and stakeholder discomfort and outstanding requests for information, illustrates how the lack of sufficient federal oversight on the asset condition project pathway governing billions of dollars of spending per year is not adequately protecting New England consumers.”[55]

It is important to note that this is one instance where state regulators have noticed and called attention to the shortcomings of a local project. As many of our interviewees noted, however, this level of enhanced scrutiny is not being applied equally to all local projects currently.

Addressing the Regulatory Gap

State, regional, and federal actors can all take steps to reduce the impact of the regulatory gap. Below, we recommend complementary reforms to improve oversight at the regional, federal, and state levels. Because the reforms are synergistic, parallel reforms at all three levels will be most effective.

Regional Reforms

State, regional, and federal actors can all take steps to reduce the impact of the regulatory gap on US transmission planning.

Overwhelmingly, the regulators and advocates we spoke with noted how essential it is for local projects to receive adequate consideration at the regional planning level. One key reason for this is that many local projects span multiple states, and only the regional planning entity has the necessary bird's-eye view over all the region's needs. As the US Department of Energy has recognized, "in many cases, [the] flexibility and optionality provided by a robust transmission plan may not be captured in individual or more narrowly focused planning processes."[56]

To address this need, we propose three reforms to strengthen regional review of local projects. These include implementing regional-first planning, standardizing local project definitions and tracking, and increasing state input into regional planning entity decision-making and governance structures. Both RTO and non-RTO regions could benefit from these actions, but they could be particularly impactful in non-RTO regions where there is no effective regional planning.

> **"Consumers and state regulators cannot make an informed decision as to whether it is necessary to rebuild a 70-year-old 138 kV line in an area that once had significant manufacturing unless it also has information as to what is going on with other utilities around the area. But in individual project reviews, such information is rarely available."**
>
> **— LS Power**, post-FERC technical conference comments[57]

Implement Regional-First Planning

FERC Order No. 1920's right-sizing requirement for local projects is limited to long-term regional planning; Order No. 1920 does not reform shorter-term regional planning or asset management projects, which could limit the provision's effectiveness. We recommend FERC require all regions to implement what we call **regional-first planning**, which would extend the right-sizing requirement to ensure that local projects are reviewed within the regional context.

We outline regional-first planning below and summarize the approach in Exhibit 13.

1. **Utilities submit local needs.** At the start of each regional planning cycle — whether short term or long term — utilities would submit all anticipated local transmission system needs within a certain forward-looking time horizon to the regional planning entity. These submissions would build on Order No. 1920 by ensuring that proposed local needs are considered in all types of planning, with the required time horizon for need identification tailored to the length of the planning cycle (e.g., 5 years for short-term and 10 years for long-term planning cycles). Importantly, we recommend that utilities submit local needs, not just local projects, to enable the regional planning entity to subsequently evaluate all needs (local and regional) at once and identify the most efficient project solutions.[xxix] A utility would also be permitted to submit local needs or projects outside of the designated submission window, but it would need to explain why it was not able to identify them earlier. If a utility submits local needs or projects outside the normal window, these should be flagged by the regional planning entity for greater scrutiny at either the state (PUC) or federal (FERC) level.

2. **Planning entity identifies the region's needs.** As already required by Order Nos. 1000 and 1920, the regional planning entity would determine what needs are likely to arise on the regional system over the planning time horizon. These needs are in addition to the local needs identified by each utility.

3. **Planning entity identifies the best solutions.** Next, the regional planning entity would determine the most appropriate solutions to meet the identified local and regional needs. During this process, it should prioritize minimizing cost and also consider the land use and environmental impacts of alternative solutions. The solutions considered should address both the local needs submitted by the utilities and the identified regional needs. Solution identification should prioritize right-sizing and alternative transmission technologies, such as GETs and advanced conductors, to maximize spending and land use efficiencies. The regional planning entity should post the selected solutions publicly, as well as all alternatives considered and the rationale for each selection.

4. **Utilities have the option to submit additional local projects.** Following the regional planning entity's identification of solutions, each utility would have the option to propose additional local projects for consideration if it feels that there are still local needs that have not been met. Any such projects would still need to undergo review by state and federal regulators and may be held to a higher standard of review.

xxix Utilities could also submit proposed local projects that could meet those needs, if desired. However, utilities should not submit projects without identifying the underlying needs those projects are intended to address.

Exhibit 13 Components of Regional-First Planning

Utilities submit proposed local needs. Transmission owners submit anticipated local needs at the start of each regional planning cycle, whether it involves planning over the short term or the long term.

Planning entity identifies the region's needs. The regional planning entity determines all regional needs holistically in addition to submitted local needs

Planning entity identifies the best solutions. The regional planning entity determines the best solutions to the identified local and regional needs, including whether local projects can be right-sized to meet regional needs and whether alternative transmission technologies can be utilized.

Transmission owner optionally submits additional local projects. Following the regional planning entity's identification of solutions, each transmission owner can propose additional local projects for consideration if they feel there are unmet local needs. Such projects must still undergo state and federal review and may be held to a higher standard.

RMI Graphic.

To our knowledge, no regional planning entity currently employs an approach comparable to the suggested regional-first planning,[xxx] and we believe FERC action will be necessary to implement such an approach at scale on a reasonable time frame. In the absence of FERC action, regional planning entities could act on their own. However, regional planning entities alone may struggle to implement regional-first planning due to resistance from the incumbent utilities that have outsized influence in the governance structures of these entities.[xxxi] Regions would also be limited by precedent, such as the exemption of asset management projects that FERC established in Order No. 890. This exemption would need to be overturned by FERC to enable regional planning entities to independently adopt regional-first planning that encompasses all types of local projects, including asset management projects.

It is important to recognize that regional planning can require considerable time and resources to produce high-quality results. This process may include setting up effective planning protocols, hiring skilled staff at the regional planning entity, and preparing modeling tools that can handle multiple inputs from different utilities. Robust stakeholder involvement, which is critical to ensure the outputs reflect diverse state and local interests, can introduce further complexities. Though the up-front investment in such a process is not trivial, the potential to reduce system-wide costs justifies the expense, as well as the potential to make better use of land and improve environmental outcomes.[58]

xxx New York ISO is starting to implement some of these practices in its Coordinated Grid Planning Process.

xxxi In many RTOs, for instance, incumbent utilities still hold significant power over how transmission planning protocols are designed. For more information, see Ari Peskoe, "Replacing the Utility Transmission Syndicate's Control," *Energy Law Journal,* 2023, **https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4577049**.

> **"One of the drawbacks and risks of the 'build-as-you-go' transmission process is the risk of construction of short-lived transmission assets that must be replaced long before the end of their useful lives due to later generation development that renders these assets inadequate and saddles ratepayers with paying for both the new and the replaced transmission assets, when pro-active planning may have produced a more efficient transmission system."**
>
> — **James McLawhorn**, North Carolina Utilities Commission, pre-FERC technical conference comments[59]

Standardize Local Project Definitions and Tracking

Although Order No. 1920 will help improve oversight and review of local projects, FERC could do more in making basic improvements to the local transmission planning process across planning regions.

One change that could help increase transparency would be to standardize the definitions of concepts used in planning processes, specifically the drivers and criteria associated with local projects.[xxxii] Currently, in some regions different utilities use different terms to refer to the drivers and criteria that determine the need for local projects. This can make it difficult for state regulators and advocates to compare projects proposed by different utilities and to meaningfully engage in regional planning processes. For instance, each utility may have different age-based thresholds for determining when to rebuild infrastructure. Terminology also varies across regions, making it difficult to compare and contrast investment patterns across the country.

Regional entities, for instance, could be required to create a standardized list of local project criteria and drivers that all utilities in their region must utilize, accompanied by clear definitions of the point at which infrastructure needs to be built.[xxxiii] FERC could then require utilities to submit this list in its existing Form No. 715.[xxxiv] Alternatively, FERC could create a standardized list for all regional entities to adhere to. Whether regional entities or FERC decide on the standardized terminology, interviewees noted that such a standardization should draw on established North American Electric Reliability Corporation (NERC)

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xxxii Drivers refer to the reason a project is deemed necessary, while a criterion is the specific violation or standard that justifies moving forward with a project at this time. An example of a driver (from PJM) is equipment material condition, performance, and risk, whereas an example of criteria is the North American Electric Reliability Corporation (NERC) reliability criteria.

xxxiii PJM, for instance, utilizes a list of five standardized drivers to describe Supplemental projects: Customer Service; Equipment Material Condition, Performance, and Risk; Operational Flexibility and Efficiency; Infrastructure Resilience; and Other (*PJM Transmission Owners Attachment M-3 Process Guidelines,* Version 0.2, last updated August 15, 2022, **https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx**).

xxxiv FERC requires that all transmitting utilities that operate "integrated transmission system facilities that are rated at or above 100 kV" must submit information via Form No. 715, otherwise known as the Annual Transmission Planning and Evaluation Report, on an annual basis. For more information, see "Form No. 715 – Annual Transmission Planning and Evaluation Report," FERC, accessed September 30, 2024, **https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-715-annual-transmission-planning-and-evaluation-report**.

reliability criteria. Interviewees also suggested that regions assign weights to criteria to help regulators prioritize the most important needs.

Going further, FERC or regions should establish a standardized approach for tracking the progress of local projects in planning and construction. For instance, regional entities could be required to share local project information in a centralized database, including data on project need, criteria, and drivers as well as updates on project costs (including cost underruns or overruns), construction status, and location. This would help stakeholders more effectively participate in the various stages of transmission planning and also monitor project cost through construction. Some RTOs have already established data sharing platforms, although the amount of data shared varies.[xxxv]

Strengthen State Input and Influence at the Regional Level

To ensure proposed projects are subjected to sufficient scrutiny at the regional level and alternative solutions are adequately considered, state regulators, consumer advocates, and other state-level stakeholders should be given ample opportunity to participate in planning. Utilities should be required to respond to stakeholder questions about the specific needs each project would meet, whether potential regional synergies and right-sizing opportunities have been sufficiently considered, and about the selection criteria applied in the process. Regional planning entities should also respond to stakeholder questions pertaining to the parts of the planning process they conduct.

Currently, however, stakeholders often have difficulty obtaining basic information about transmission investment decisions. As we have documented, many state regulators and consumer advocates have found that utilities either fail to respond to their questions or provide answers with insufficient detail to prove useful.

xxxv For instance, PJM's Transmission Cost Planner tool shares some data on local project name, driver, and cost. However, the tool does not share construction-stage updates, including any information on cost underruns or overruns. For more information, see "Transmission Cost Planner," PJM Interconnection, accessed August 26, 2024, **https://tcplanner.pjm.com/tcplanner**.

Strengthening the ability of state-level stakeholders to provide input to and influence regional transmission planning processes is therefore another strategy that could help address the regulatory gap. Where RTOs and ISOs exist, they could consider adding voting authority for state voices or other special forums for input. For instance, MISO has a voting sector comprised of public consumer advocates.[60] Any special forums should ensure that adequate information is shared by utilities to allow state-level stakeholders to meaningfully participate.

Forming independent groups to enable state regulators and consumer advocates to more effectively engage in regional planning processes could also help close the regulatory gap. Today, regulators in the four multistate RTOs have regional groups of state regulators, as does the non-RTO West.[xxxvi] Expanding this model to the non-RTO Southeast could strengthen state influence in planning. PJM also has an active regional organization representing state consumer advocates, called the Consumer Advocates of PJM States (CAPS), but no other regional planning entity has a similar consumer advocates group to our knowledge. Expanding the CAPS model to all the planning regions could help foster dialogue, collaboration, and collective advocacy among state consumer advocates.

FERC could also give state regulators an explicit role in regional transmission plan development. State regulators, for instance, could be given an easily accessible pathway to submit any concerns to FERC with the completion of each regional plan.[xxxvii] Such a requirement could establish a routine pathway for PUCs to provide input on the regional plan, help elevate their important perspectives, and alert FERC to issues it should consider examining in detail. If persistent concerns emerge, FERC could then take action via Section 206 of the Federal Power Act to amend that regional planning entity's planning processes.

Regardless of the mechanism of input, PUCs, consumer advocates, and other state-level stakeholders have critical roles to play in ensuring that planning processes at the regional level are conducted in a rigorous and transparent manner. They can also push for changes in how planning is conducted, such as by advocating for the adoption of regional-first planning. This could be particularly impactful in non-RTO regions where regional planning has yielded no regionally planned projects to date, because this has left significant potential savings on the table.[61]

Federal Reforms

In addition to the regional reforms laid out above, FERC could take several steps to ensure that local transmission projects receive adequate oversight. We recommend FERC consider refining the formula ratemaking process, establishing an independent transmission monitor (ITM), and exploring performance-based regulation (PBR) for transmission. FERC could take action on these items under its open AD22-8 docket on transmission planning and cost management, or the commission could address them in other venues.

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xxxvi In RTO states, these groups are the Organization of PJM States, Inc. in PJM; Organization of MISO States in MISO; Regional State Committee in the Southwest Power Pool (SPP); and NESCOE in ISO-NE. For more information, see Christopher Parent et al., *Governance Structures and Practices in the FERC-Jurisdictional ISOs/RTOs*, Exeter Associates, prepared for New England States Committee on Electricity, February 2021, **https://nescoe.com/wp-content/uploads/2021/02/ISO-RTOGovernanceStructureandPractices_19Feb2021.pdf**. In the non-RTO West, the Committee on Regional Electric Power Cooperation (CREPC) and Western Interconnection Regional Advisory Body (WIRAB) are made up of regulators and state energy officials from all 14 states and 2 provinces in the Western interconnect. CREPC and WIRAB engage on regional electricity issues including markets, reliability, and transmission.

xxxvii There are examples of states in RTOs exercising authority over other topics related to transmission planning. In SPP, for instance, the Regional States Committee has retained filing rights under Section 205 of the Federal Power Act over transmission cost allocation and resource adequacy matters. In ISO-NE, NESCOE can request that utilities file an alternative proposal related to transmission cost allocation. For more information, see Parent et al., *Governance Structures and Practices in the FERC-Jurisdictional ISOs/RTOs*, February 2021.

Reform the Formula Rate Process

As noted earlier, under FERC formula rates, project investments are approved through an annual update filing rather than a contested process. This reduces the opportunity for challenges to FERC's presumption of prudence. In addition, the rate of return granted by FERC's formula rates is generous and can be larger than the rates PUCs offer utilities for the investments they regulate at the state level.[xxxviii] This means that if a utility overspends on a local transmission project, it can expect to earn an attractive return with little risk that it will be denied cost recovery by any regulator.

To address these issues, we recommend FERC:

1. **Remove the presumption of prudence for projects that have not undergone a robust regional or state regulatory review.** The reason natural monopolies like transmission are rate regulated is to protect customers from being overcharged, so ensuring that investments are prudent is a core duty of regulators. Thus, if a project has not already undergone a rigorous regional or state-level review, FERC should not automatically assume that the project is needed or that expenditures on the project were prudent. Instead, FERC should require that the utility demonstrate that the investment was prudent, just as the utility would be expected to do if it presented the costs for recovery in a rate case. It would then be up to the utility to convince FERC that the project was prudent or, alternatively, to seek a robust regional or state review. Such a review could include a thorough study by a regional planning entity (including a right-sizing analysis, the evaluation of alternatives, consideration of alternative transmission technologies, and cost-benefit analyses) or prior approval by a PUC at the state level (e.g., through issuance of a CPCN).

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xxxviii In the United States, evidence indicates that the returns on equity (ROEs) utilities earn are generally substantially more than their true cost of equity (i.e., the ROE they actually need to attract equity investors). This is indicated by the fact that most utilities have price-to-book ratios above 1. A utility's price-to-book ratio reflects the enterprise-wide ROE (i.e., both the allowed ROE set by the PUC for state-regulated assets and the ROE set by FERC for transmission assets), but there is no obvious reason to believe that FERC-set ROEs are less generous than PUC-set ROEs. In fact, the opposite may be true, both because the FERC-set ROEs are often higher than those set by state PUCs, and because the formula rate process employed by FERC reduces the risk to utility investors that the utility's costs will not be recovered. For more on this topic, see Mark LeBel et al., *Improving Utility Performance Incentives in the United States: A Policy, Legal and Financial Framework for Utility Business Model Reform*, pp. 20–27, Regulatory Assistance Project, **https://www.raponline.org/wp-content/uploads/2023/10/rap-improving-utility-performance-incentives-in-the-united-states-2023-october.pdf**; and Jim O'Reilly, FERC Regulatory Review, RRA Regulatory Focus, S&P Global, Topical Special Report, pp. 14–17, June 28, 2024, **https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/file?keyfileversion=FB57DFC2-A117-68C7-A0CF-63E5307FD8A0&KeyFileFormat=3&isNewsletter=1**.

2. **Lower the evidentiary standard for parties interested in raising challenges as part of formula rate cases.** Because FERC currently assumes that all transmission investments are prudent, the burden falls on other stakeholders to prove otherwise. Any challenges must meet an evidentiary standard referred to by FERC as "serious doubt."[62] Yet state regulators and other stakeholders are often unable to assess prudence because they lack access to key transmission data and modeling tools, and to gain access, they would somehow need to produce preliminary evidence of imprudence. Several interviewees noted that as a result of this catch-22, it has proven difficult for stakeholders to challenge the prudence of local transmission projects before FERC. FERC could address this by lowering the evidentiary standard required to trigger consideration of prudence from "serious doubt" to one of "reasonable questions" raised by parties about factors such as project cost or consideration of alternatives. Parties should also be allowed to conduct discovery without the restrictions imposed by a utility's formula rate protocols, which can limit information disclosure requirements. This would allow these parties to more easily meet the evidentiary standard.

3. **Remove the return on equity (ROE) adder for RTO membership for local projects that do not undergo a robust regional review.** FERC currently offers an ROE adder (a type of financial incentive) for all transmission projects that are built by a utility with membership in an RTO or ISO, the purpose of which is to encourage participation in these regional entities. However, this logic does not hold for local projects that are not effectively part of the regional planning process. It would therefore be reasonable for FERC to remove this adder for projects that have not been sufficiently reviewed by a regional planning entity. Doing this would also create a financial incentive for utilities to seek regional review of local projects.

4. **Reduce the allowed ROE for local projects.**[xxxix] In addition to removing the ROE adder for local projects that have not undergone a robust regional review, FERC could consider reducing the allowed ROE on all local projects to incentivize greater investment in right-sized regional solutions. This may also be appropriate on the grounds that utilities face less risk when building small local projects than when building larger regional ones.

Establish an Independent Transmission Monitor

Many of the state regulators and staff we interviewed emphasized that even if transmission planning processes were improved, their ability to rigorously review local transmission projects would still be hampered by limited staff expertise and insufficient information and data from utilities. An ITM, whether established for each regional planning entity or housed within FERC at the federal level, could serve as an important information clearinghouse for state regulators. For instance, the ITM could regularly review utility spending trends, consider whether projects are subject to sufficient regulatory oversight, and evaluate whether transmission spending is economically efficient. The ITM could also assist state regulators, upon request, to understand information about a specific project presented by a utility. Moreover, the ITM could help ensure that regional-first planning, once implemented, is functioning properly. FERC could further explore what needs an ITM could fill and how it should be structured; several comments in its AD22-8 docket are relevant to these questions and could provide a basis for consideration of the ITM idea. Regardless of where the ITM is housed, it will be important to structure it in a way that provides value to states and ratepayers without unnecessarily adding additional barriers to transmission deployment.

xxxix The allowed ROE is the return included by FERC in the formula by which rates are set. This may be higher or lower than the realized ROE, which is the return the utility actually earns.

Explore Performance-Based Regulation for Transmission

Performance-based regulation is an alternative to traditional cost-of-service regulation that seeks to better align the incentives utilities face with the interests of customers and society. PBR is not a single mechanism, but rather a set of tools that regulators can tailor to the specific needs and policy priorities of their jurisdictions. Though PBR has mainly been applied by PUCs in the United States, FERC could adopt PBR aspects at the federal level.[xl]

In Order No. 679 in 2006,[xli] FERC noted that "the development of PBR measures may represent a long-term goal for the industry and the Commission to pursue . . . [and] we intend to continue to work with the industry to encourage development of PBR proposals."[63] However, to date FERC has yet to issue additional PBR guidance.[xlii]

FERC could use PBR to improve transmission regulation in various ways by discouraging perverse utility incentives and rewarding efficient transmission planning. PBR could help address the existing incentive utilities have to spend more than necessary on capital projects (a perverse incentive known as gold-plating) and address the incentive to prefer capital investments over other alternatives (a perverse incentive known as capital expenditure [capex] bias). For example, PBR could offer utilities a share of any cost savings they can achieve through lower-cost alternative transmission technologies.[64] In addition, a number of capex–operational expenditure (opex) equalization strategies exist that could help level the playing field between utility capital projects and alternative opex solutions, such as third-party services and demand flexibility programs.

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xl PBR has also been used to regulate utilities in the Canadian provinces of Alberta, Ontario, and Quebec; Great Britain; Australia; and many other countries.

xli This rulemaking followed the Energy Policy Act of 2005, which in Section 219 required that FERC explore incentive-based ratemaking for transmission.

xlii In RM 20-10 — in which a Notice of Proposed Rulemaking (NOPR) was issued on March 20, 2020, and a Supplemental NOPR was issued on April 15, 2021 — FERC indicated that it may consider revisiting the ROE adders first explored as part of Order No. 679. These include a 100 basis point adder for transmission technologies that enhance reliability and increase efficiency and capacity. However, FERC has yet to act on these notices.

Performance incentive mechanisms (PIMs) could also be worth exploring. A PIM ties a financial incentive — in the form of a reward, a penalty, or both — to utility performance in a defined area. PIMs could be used in various ways to encourage more efficient transmission operation and planning. For example, one PIM could reward utilities for reducing system congestion and another PIM used to penalize them for failing to participate appropriately in regional planning processes.[xliii]

The thoughtful use of these and other PBR tools could save customers money, encourage the development of more innovative solutions to grid needs, and reduce land use and environmental impacts. If FERC wishes to take up the topic of PBR in transmission once more, a technical conference or notice of inquiry could be an appropriate way to begin the discussion.

State Reforms

In addition to regional and federal improvements, states can play important roles in regulating local transmission investments. Below, we suggest some reforms states can implement to strengthen the oversight of local projects.

Leverage and Expand CPCN Authority

Even where PUCs have few tools to influence local project planning, they may have the authority to review projects at the siting stage when the utility applies for a CPCN. While a CPCN requirement is not enough to enable a PUC to ensure utility projects are well planned and prudent, it does provide additional transparency and the ability to require siting-related changes. Strengthening a state's CPCN requirement — or if no such requirement exists, establishing one — is one potential strategy states can use to strengthen oversight.

As discussed earlier, many states have a voltage threshold and/or asset replacement exemptions for CPCN review. These exemptions can significantly limit the PUC's ability to review smaller local projects and may also create an incentive for utilities to prefer smaller local projects over larger ones. The state legislature could address this issue by updating the CPCN requirement to give PUCs broader authority. For example, if the enabling statute currently specifies a voltage threshold of 138 kV, reducing it to 69 kV would ensure that more local projects are reviewed by the PUC. If an asset replacement exemption is in place, the state legislature could also update the statute to require that all projects replacing or expanding existing infrastructure receive a CPCN. If a standard CPCN is deemed impractical, these projects could require an expedited CPCN instead.

Even in the absence of legislative reforms, PUCs can take steps to strengthen existing CPCN review requirements. For instance, PUCs could require utilities to document that they have sufficiently explored project alternatives when they apply for a CPCN. This requirement could identify specific alternatives that must have been examined (e.g., GETs, advanced conductors, and non-wires alternatives such as storage), certain steps that must have been taken (e.g., consideration of right-sizing), and particular information about the downselection process that must be provided (e.g., the criteria used and how each alternative was rated based on those criteria). As another example, a PUC could require the utility to demonstrate

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xliii For more on perverse incentives, as well as PIMs, capex-opex equalization strategies, and other elements of the PBR toolkit, see Kaja Rebane and Cara Goldenberg, *How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation*, RMI, 2024, **https://rmi.org/insight/how-to-restructure-utility-incentives-four-pillars-of-comprehensive-performance-based-regulation/**.

that the project received robust regional review by the relevant regional planning entity — or if it did not, to explain why that is the case. Once such requirements are in place, the PUC could deny the CPCN if the utility fails to meet them.

Expanding CPCN review in these ways could strengthen the PUC's ability to conduct oversight of local projects. However, even a well-designed CPCN requirement is not a substitute for robust regional planning, and it cannot on its own bridge the regulatory gap.[xliv]

Offer Expedited Cost Recovery for Local Projects that Undergo a Robust Regional Review

Even though states cannot unilaterally change FERC-approved transmission charges, they do have the ability to design the rates for end-use customers through which the allowed costs are recovered. Though most PUCs have adopted the use of rate riders that quickly pass through the FERC-approved transmission costs to customers, this is not the only option. For example, a PUC could instead review and approve transmission costs for recovery during rate-case proceedings, just as other utility capital costs are traditionally handled. Approving transmission costs for recovery during rate cases would still enable the utilities to recover their approved costs, but it would also increase regulatory lag (i.e., the time between when a cost is incurred and when it is recovered from customers). Because of the time value of money, utilities prefer rate riders over this more traditional ratemaking treatment, but both are equally valid from a regulatory perspective.

This means states could offer utilities the option of more favorable rate design as a carrot for good transmission planning, rather than adopting it as the default option. Kansas is an example of a state that has adopted this approach, as detailed in Box 4.

xliv Interviewees also noted that when local projects span multiple states, regional review is even more essential for cost-efficient and effective transmission planning.

Box 4

How Kansas Encourages More Efficient Transmission Planning

For years, Kansas had permitted utilities to recover transmission-related costs through a rate rider called the transmission delivery charge, which is codified in K.S.A. 66-1237. However, in the last few years, state policymakers became concerned about the increasing share of utility spending devoted to local transmission projects. At the time, the PUC (the Kansas Corporation Commission) and stakeholders had limited visibility into these projects, including the specific problems they were intended to solve, the process that led to their selection, and their projected costs. Policymakers also recognized that because the ROE offered by FERC for local transmission projects was higher than the ROE offered by the state for distribution projects, utilities might be inclined to seek ways to substitute transmission spending for distribution spending.

To address these concerns, in 2023 Kansas amended K.S.A. 66-1237 to distinguish between the use of the transmission delivery charge for cost recovery related to RTO-directed projects versus local projects.[65] Under the amended statute, transmission projects that have passed through the RTO's planning process remain eligible for rider treatment with no further conditions, but if a utility wishes to use the rider to recover the costs of a local project it must fulfill two additional conditions:

1. **Transparency.** The first condition is a set of requirements designed to increase transparency. These include the provision of key information about each project (e.g., the expected in-service date, cost, and location; whether the project is classified as a new build, rebuild, upgrade, or other type of project; a description of the purpose of the project; the vintage of any facilities the project is intended to replace; and the identification of any load additions or economic development benefits). The utility is also required to conduct a technical conference with PUC staff and other parties within 90 days of each compliance filing and a public workshop within 120 days of the filing.

2. **ROE.** The second condition is that the utility must accept the use of the state-approved ROE instead of the FERC-designated ROE.

If a utility does not wish to comply with these two conditions, it remains eligible to apply for cost recovery for its local project through means other than the rider. However, the attractiveness of the transmission delivery charge to utilities, primarily associated with reduced regulatory lag, creates an incentive for utilities to consider their options.

The amended statute has already had a positive impact on transparency in Kansas. It has enabled both regulators and stakeholders to better understand local transmission planning and to ask the utility questions, such as why a particular facility needed to be replaced or why a utility chose a traditional upgrade rather than a GETs alternative.

Although Kansas's approach is not sufficient to resolve the regulatory gap, it may reduce utilities' incentive to pursue local projects instead of regional ones. Kansas's legislation also increases regulators' and stakeholders' visibility into local transmission planning decisions. This enables greater transparency, and if a utility expects to have to publicly justify the decisions it makes, it may be inclined to make better decisions in the first place.

Update Integrated Resource Plans to Incorporate Transmission

Most PUCs that regulate vertically integrated utilities require the investor-owned utilities in their state to develop and file IRPs. Most of these IRPs do not consider transmission costs or evaluate transmission as a solution to meet demand.

Updating IRP requirements to incorporate transmission into planning is one near-term strategy states can use to gain more insight into utility transmission planning and influence the process early on. For example, states could require that within the IRP process, utilities include specific details about their transmission expansion plans, evaluate technologies that increase transmission capacity, such as GETs, and model transmission as a resource, along with new generation options.[xlv] More broadly, states could require utilities to discuss how they are utilizing a regional-first planning approach in partnership with the regional planning entity.[66]

Create and Fully Leverage Electric Transmission Authorities

Through legislative action, a few US states have created **electric transmission authorities** to coordinate transmission development. Examples include the New Mexico Renewable Energy Transmission Authority and the Colorado Electricity Transmission Authority (CETA). These bodies have been designed to operate in an independent fashion, which makes them well positioned to support cost-effective and reliable system planning and to identify gaps between utility-proposed projects and state needs. Transmission authorities can be of particular help in non-RTO regions, where regional planning is generally much more reduced in scope.

Existing transmission authorities have already had a positive impact on transmission development by enabling a cost-effective planning approach. In Colorado, for example, CETA was tasked with analyzing the need for expanded transmission capacity and evaluating all of the transmission technology options available (including new builds, rebuilds, reconductoring, and GETs).[xlvi] CETA identified over 3,700 miles of transmission needs, approximately 80% of which could be met through cost-effective rebuild or reconductoring solutions.[67] To realize similar benefits and better enable regional-first planning, states that do not currently have transmission authorities could consider creating them and task them with conducting a study on the transmission needs within their state and region.

Grow Regulatory Staff Capacity and Expertise

Even when PUCs have the authority to oversee aspects of the transmission planning process, their ability to conduct high-quality oversight is often limited by insufficient staff capacity and expertise. Although these constraints also affect other spheres of PUC activity, our interviews indicated that they may be particularly pronounced where transmission is concerned. This lack of sufficient staff capacity and expertise can also limit a state PUC's ability to engage thoroughly at the regional level as part of regional transmission planning processes.

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xlv The Oregon Public Utilities Commission requires utilities to consider transmission as a resource option alongside generation assets in their resource plans. This includes incorporating traditional and nontraditional benefits of transmission ("Disposition: Appendix to Order No. 07-002 Corrected," Oregon PUC, February 9, 2007, **https://apps.puc.state.or.us/orders/2007ords/07-047.pdf**).

xlvi SB23-016 requires CETA to study the need for expanded transmission capacity in the state of Colorado by January 31, 2025 (SB23-016: Greenhouse Gas Emission Reduction Measures, Colorado General Assembly, 2023, **https://leg.colorado.gov/bills/sb23-016**).

State legislatures could help address this issue by increasing the budgets and staff capacity of PUCs, either overall or in a manner targeted at transmission specifically. This could enable PUCs to hire more staff, provide more training opportunities to help staff develop transmission-specific expertise, and hire third-party experts where necessary to supplement in-house resources.[xlvii]

Though state legislatures have the largest role to play in ensuring PUCs have sufficient resources to conduct proper oversight, other actors can also play valuable roles in developing commissioner and staff expertise. For example, the National Association of Regulatory Utility Commissioners (NARUC) offers trainings and other educational resources geared to the needs of its membership, and some nonprofit organizations host workshops, offer fellowships that focus on developing specialized expertise, and support professional networks that enable peer-to-peer learning.[xlviii] By tailoring their offerings to focus on key transmission-related topics, these organizations could help PUCs develop the in-house expertise they need.

xlvii For example, the North Carolina Utility Commission recently put out a request for proposals for technical expertise to help them review transmission projects better (see the remarks by James McLawhorn at the FERC technical conference on October 6, 2022). For broader discussion of reforms that could help PUCs be more effective, see Jessie Ciulla et al., *The People Element: Positioning PUCs for 21st-Century Success*, RMI, 2022, **https://rmi.org/insight/puc-modernization-issue-briefs/**.

xlviii One such example is Regulatory Collaborative, a PUC staff cohort that offers a space for collaboration and problem-solving on emerging topics, such as near-term solutions to potential load growth. For details, see “Reg Lab,” RMI, accessed September 5, 2024, **https://rmi.org/reg-lab/**.

Conclusion

The effectiveness of transmission planning in the United States is currently hampered by a regulatory gap, in which many local transmission projects do not receive adequate review by state, regional, or federal entities. Utilities can take advantage of this gap by pursuing local projects instead of pursuing more cost-effective regional solutions.

This is an inherently inefficient way to conduct the process of grid investment. Many uncoordinated local projects will generally be more costly than larger, well-planned regional projects, and they will also tend to have greater land use and environmental impacts and fewer economic and operational benefits. This approach also misses a key opportunity to proactively design the grid of the future rather than simply rebuild the grid of the past.

Unfortunately, evidence indicates that local transmission spending has increasingly displaced regional investment in recent years. If this trend continues, it will be difficult to meet the dual demands of accelerating load growth and the clean energy transition in a cost-effective manner. At a time when many customers already struggle to pay their utility bills, this is a problem that policymakers should proactively work to address.

In this report, we identify a number of reforms at the regional, federal, and state levels that can help strengthen the regulatory oversight of local transmission investments and produce better planning results. Only then can customers be confident that they are getting the most “bang for their buck,” as former FERC Commissioner Rich Glick phrased it, with respect to transmission investment.[68]

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RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org

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Turning Data Centers into Grid and Regional Assets: Considerations and Recommendations for the Federal Government, State Policymakers, and Utility Regulators

OCTOBER 2024

Nora Wang Esram and Neal Elliott

Key takeaways

- Data centers are competing with manufacturing facilities for electricity, potentially extending the use of fossil fuel power plants and derailing states' and companies' climate goals.
- Industrial electricity demand growth has not been accurately factored into current demand projections. Those demand projections are likely too low.
- Policymakers must address this dual challenge together rather than viewing industrial growth and data center growth as competing forces that require choosing one over the other.
- Some legislators are reexamining incentives for data centers because of the abovementioned competition and because communities are objecting to data centers' noise, water consumption, and impact on electricity costs.
- A promising solution to electricity adequacy concerns is to convert data centers into grid and regional assets, with flexible demand that is powered by carbon-free electricity.
- RTOs and ISOs (regional transmission organizations and independent system operators), utilities, and data center developers and operators must join in this coordinated effort. Successful implementation of these recommendations also needs buy-in and support from utilities, information and communications technology companies, local governments, and communities.
- Three key steps the above actors need to take immediately are (1) fill data and knowledge gaps in AI data center design and operation, (2) improve AI data centers' energy efficiency and integration with regional infrastructure and the grid, and (3) develop policies that transform demand-side strategies for all customers.

Data centers are driving massive growth in electricity demand—just as U.S. manufacturing is surging

Over the last two years, America's demand for electric power has surged thanks to the resurgence of U.S. manufacturing and the emergence of—and demand for—artificial intelligence (AI) and generative AI (GenAI) that rely on power-hungry data centers. The manufacturing surge is substantially driven by Biden administration policies—BIL, CHIPS, and IRA—prompting major investments in new manufacturing facilities powered by electricity. Together, new industrial loads plus new loads from data centers have reversed a long period of flat electricity demand since 2007. The emergence of these two substantial new electric loads is unprecedented, and policymakers must address this dual challenge rather than viewing industrial growth and data center growth as competing forces that require prioritizing one over the other.

This trend is especially challenging at a time when many U.S. states and private companies are setting ambitious goals to reduce or even eliminate carbon emissions in the near future. One study[1] projected that the combined expansion alone of traditional and AI data centers and chip foundries will increase electricity demand from 130 terawatt-hours (TWh) in 2023 to 307 TWh in 2030. This increase is higher than the projected growth in EV power demand, which is expected to rise from 18.3 TWh in 2023 to 131 TWh in 2030. In fact, it is equivalent to a projection of total demand growth of 175 TWh across the residential, commercial, and industrial sectors during the same period.

Industrial demand growth has not been fully captured in many demand growth projections because planning and constructing a new mega factory takes considerably longer than building a data center. However, this growth is on the horizon, fueled by new investments in clean energy manufacturing—currently driven by semiconductors, batteries, electric vehicles, wind, and solar—supported by both the private and public sectors.[2]

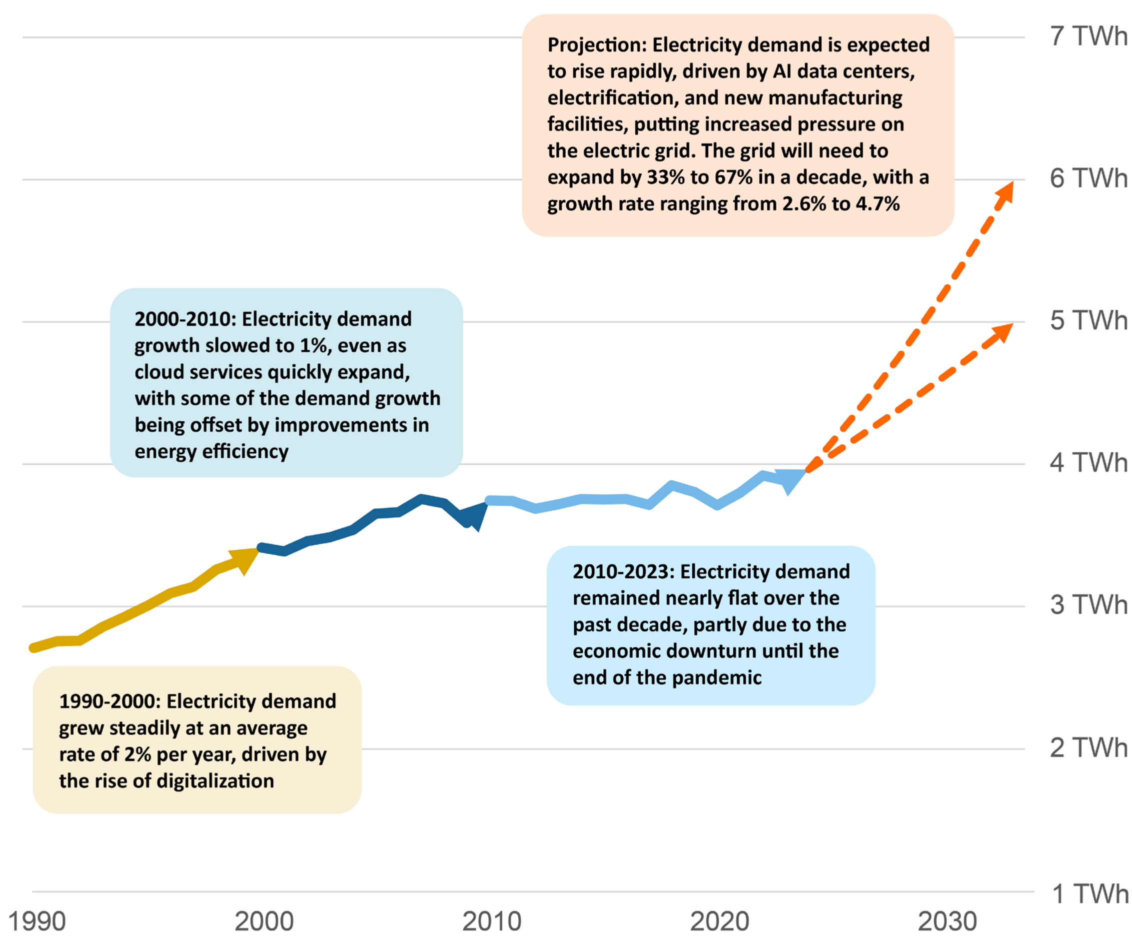

Figure 1. Industry and GenAI are competing for electricity, threatening states' carbon goals

Electrical load growth puts achieving carbon goals at risk

The transition to low-carbon electricity is a pivotal strategy to reduce industrial greenhouse gas emissions.[3] States' industrial economic development opportunities now face direct competition from the information and communications technology (ICT) industry's push to site new data centers. This trend has slowed the increase in the share of carbon-free electricity in the grid mix because utilities have chosen to meet these new loads through conventional means, such as extending the operating lives of fossil fuel power plants or constructing new gas-fired generation. This trend puts our country's climate and economic growth goals—and the goals of many companies—at risk.

Some GenAI data centers consume more energy than even the most energy-intensive facilities we are accustomed to and that the grid was built for. For example, traditional data centers, which can meet the computation requirements of machine learning but not GenAI, consume around 7.5 kilowatts (kW) per rack of servers. However, just *one* of the new servers essential for high-performance AI tasks requires over 10 kW.[4] Consequently, the power and heat density of a GenAI center is at least four times that of a comparable cloud-computing facility (e.g., those used by Amazon Web Services [AWS], Microsoft Azure, and Google Cloud) or a colocation data center (where businesses can rent space to house their servers). OpenAI CEO Sam Altman has suggested that the United States needs to commit to building multiple five-gigawatt (5,000 MW) data centers in various states to advance AI and compete with China.[5]

Rising electricity demand from artificial intelligence and the expansion of data centers have significantly increased scope-1 and scope-2 greenhouse gas emissions. This surge presents a challenge for tech giants like Google and Microsoft,[6] utilities such as Dominion Energy, and state and local governments, including Loudoun County in Virginia,[7] in achieving their clean energy and carbon neutrality goals. Reliance on renewable energy certificates and carbon offsets is insufficient to curb this growth. As a result, some companies may face tough decisions between pursuing business opportunities and upholding their carbon commitments, potentially risking public and constituent support. Rhodium Group's latest projections suggest that rapid load growth—combined with unanticipated headwinds in grid carbon-free electricity supply—could dramatically slow the rate of U.S. decarbonization.

Geographic considerations: uneven distribution of electric loads

The increase in demand is not uniform. Immediate shortfalls in electricity supply are particularly acute in the Southeast, Southwest, and Midwest, where manufacturing and data center construction are surging.[8]

These power-hungry locations are at the nodes of the fiber backbone (see the figure below). For example, in Ohio, GenAI competes with Intel's Chip Fabs and Cleveland Cliffs' Middletown direct reduction iron project. The Public Utility Commission of Ohio has new rules for connecting data centers that discourage their location through high interconnection charges. Other states are considering similar responses.

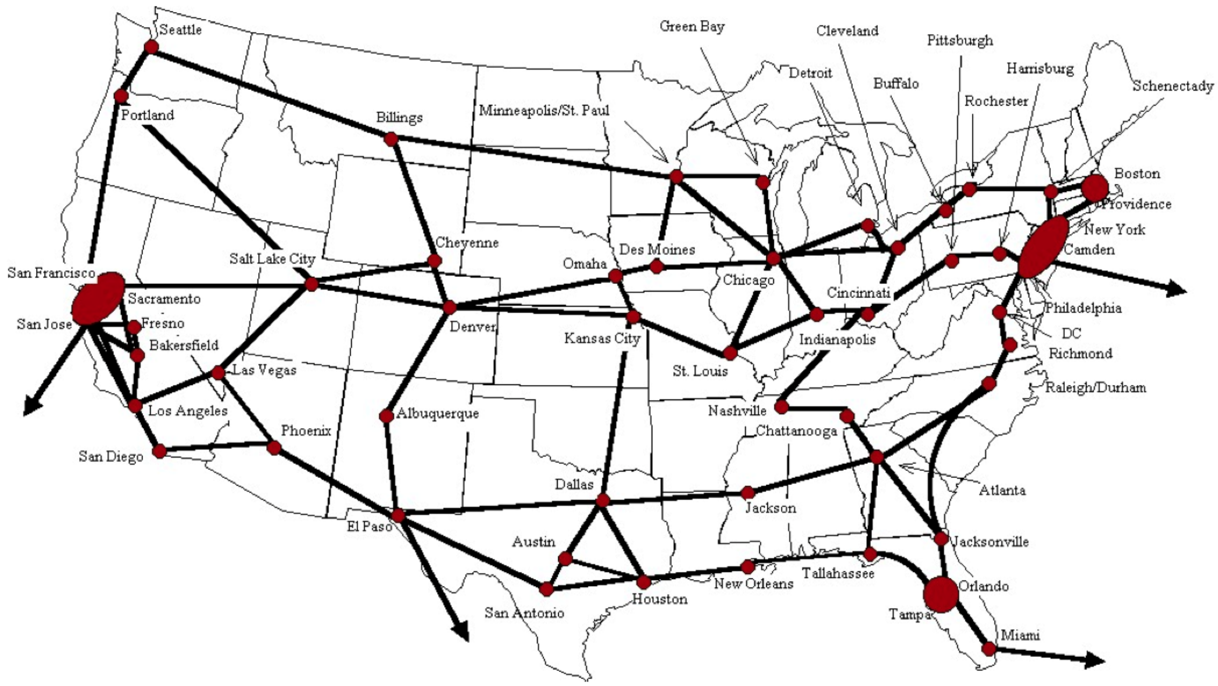

Figure 2. U.S. fiber backbone. Source: Brown, Elliott and Shipley 2001.[9]

Data centers can increase household energy bills and affect environmental quality; communities are starting to resist

AI data centers are currently being built near many communities, often without residents being informed. The data centers create noise, use large amounts of water, and can increase energy bills for nearby households. In Santa Clara, the heart of Silicon Valley, rising electric rates are driven by the municipal utility's significant spending on transmission lines and other infrastructure to meet the enormous power demand of over 50 data centers, which now account for 60% of the city's electricity consumption.[10] Data centers typically pay lower rates for electricity than residential customers.

A study on the environmental footprint of data centers in the U.S. estimated that in 2018 (two years before ChatGPT was publicly released), they consumed 5.13×10^8 cubic meters, or 135 billion U.S. gallons, of water,[11] equivalent to about 0.4% of the total annual water withdrawals in the United States. Less than 1% might not seem significant, but when data center water consumption is concentrated in a small region, it can account for a quarter of a town's annual water consumption, as revealed during a lengthy legal battle in Oregon.[12] Additionally, one-fifth of data centers draw water from moderately to highly stressed watersheds in the western United States.[13] The rapid growth of resource-intensive AI data centers will further exacerbate water scarcity in some regions. Growing concern that big tech companies have kept data center development secret to avoid community involvement is leading to calls for more transparency and regulation.[14]

Data centers generate limited long-term local jobs, although they bring tax revenue

Although data centers create construction jobs and drive demand for construction materials and IT equipment, they typically have relatively low long-term local employment. While headquarters, manufacturing, or shared service operations may have 200 to 1,000 jobs onsite, a typical data center usually employs significantly fewer people. One study estimates that the number of jobs at a typical data center can be between 5 and 30,[15] and another study states that a typical data center (with a capital expenditure of over $215 million) directly supports 157 local jobs.[16]

Data centers have been a significant source of tax revenue, making them attractive to state and local policymakers. For example, the data center industry is estimated to bring $1.2 billion in tax revenue into the Virginia economy annually, including $1 billion to local municipalities and $174 million to the state.[17] However, this revenue boost has not been adequately assessed in the context of increasing electricity demand and its broader impact. While more comprehensive studies on the indirect and induced jobs created by data centers, as well as comparisons with other economic development options, are needed, some states' legislators, such as in South Carolina, Georgia, and Virginia, are reexamining incentives for data centers, since they may lead to higher utility costs for residents, limited job creation, and other adverse environmental effects.[18]

Just as clean manufacturing facilities compete with data centers for electricity from the grid, they create some of the same problems for communities—noise and water pollution and higher electricity bills for all customers. As this competition intensifies, the sector that can turn its facilities into grid and regional *assets* may face less opposition to new development and take the lead in sustainable growth.

A promising solution is to transform data centers into grid and regional assets with flexible demand powered with carbon-free electricity.[19] These centers can reduce energy consumption during grid strain, ramp up usage during renewable energy surpluses, and even store excess electricity to feed back into the grid, improving grid reliability and resilience.

Grid asset traditionally refers to physical components that make up grid infrastructure, including equipment for generation, transmission, distribution, metering, and communication. The transition to a modern and smart grid has expanded the definition to include customer-side solutions (e.g., smart appliances, EV charging stations) and control technologies (e.g., distribution management and automation systems, advanced analysis and visualization software).

Regional asset refers to any resource, capability, or infrastructure within a defined geographical area that can be leveraged to enhance the efficiency, effectiveness, and reliability of local utility systems and services. A region can be a district, city, county, or even a larger area, depending on structure and distribution of the utility infrastructure.

For example, Enel X[20] has developed a way for data centers to participate in grid services by using their uninterruptible power supplies (UPS), backup generators, and battery storage as part of a virtual power plant. Verrus aims to build new data centers that segregate critical and non-critical loads, powered by microgrids that utilize batteries and flexible data center loads to reduce energy costs and carbon footprints.[21] While new technologies like these show promise, using data centers as grid assets is still an emerging field.

States that can lead—by charting a path to data centers as grid and regional assets—will be best positioned to attract new technology companies and reap the rewards they bring, including jobs and economic growth. They will also maintain momentum toward meeting their carbon reduction goals.

Conventional efficiency measures and operational optimization are inadequate to manage GenAI data centers

Since the emergence of data centers in the late 1990s, continuous improvements in energy efficiency and operational optimization enabled by server virtualization have held down energy demand as processing and data communication volumes have increased exponentially.[22] Server virtualization is a technology and process that creates multiple virtual machines on a physical server, with each virtual machine operating independently. This allows multiple users to perform different tasks on the same server, maximizing its utilization and reducing total energy use (compared to running multiple servers at partial capacity) and associated carbon emissions. With these measures, data center energy use can be reduced by as much as 80%.[23]

Energy efficiency measures include efficient devices (chips, servers, processors, power supplies), efficient arrangement of server racks, efficient cooling systems, and data center energy management.

Data center is a general term that can refer to a range of facilities housing computer servers and networking equipment with very different power and market characteristics. These data centers can be grouped into four different market categories:

- Hyperscale cloud computing infrastructure operated by large technology companies (e.g., AWS, Google, Microsoft) hosts customers' software (from small businesses to large companies like Netflix). Large cloud service providers can use networks of data centers to route workloads to those with the best access to renewable energy at any given time, or they can help customers optimize their workloads to run during times of lower grid carbon intensity.
- Co-location services result in limited grid responsive behavior when they provide connectivity, power, cooling, and facilities for customer servers, but where the operators (e.g., Iron Mountain) have limited control of their customers' server utilization and energy use.
- Crypto mining seeks locations with cheap electricity rates to improve profitability. Many Bitcoin mining companies participate in formal demand response programs, where they agree to curtail operations when called upon by grid operators during peak events.
- Artificial intelligence (AI), an emerging category that typically uses arrays of graphic processing unit (GPU[24]) based servers to train large language models and respond to queries using these models (known as inference). While some AI workloads can be challenging to virtualize efficiently, advancements in GPU virtualization are improving flexibility. Training large models often results in high load factors (i.e., the ratio of average energy consumption to peak load over a specified time period), while inference workloads may have more variable load factors. How to fully utilize this flexibility has not been well explored.

However, the traditional data center energy efficiency and server optimization measures discussed above are only partially effective for handling the proliferation of current GenAI data centers. These new data centers create unprecedented electricity demand due to their much higher power density, increased cooling demand, constant high utilization (i.e., high load factors), different computational patterns (compared to traditional enterprise applications), and rapid scaling. Consider Dominion Electric, Virginia's largest utility. Dominion took 115 years to reach its current power delivery capacity. However, with the rapid growth of data centers in Virginia, Dominion is on track to double its system load within the next 15 years—a scale and speed of expansion that is unprecedented.[25] While the future trajectory of data center electricity demand remains uncertain, the current rapid pace of growth is creating immediate challenges, even though electric supply and infrastructure may eventually expand to meet future needs.

Data centers have the potential to lower emissions and cut electricity costs—if their owners have the right incentives

Instead of viewing AI data centers as a threat to the grid and local economic development because they compete with other job-creating industrial sectors and climate goals, it is possible to transform them into valuable grid and regional assets.

However, without proper incentives, data center owners, operators, and even their customers have little reason to pursue these opportunities, resulting in a failure to take advantage of data centers' full potential of demand flexibility. Realizing this potential relies on the collaborative efforts of technology developers and providers, utilities, and governments—all supported by corresponding industrial standards and regulatory frameworks.

As grid assets, AI data centers have the potential to adjust power consumption during peak demand periods, helping utilities avoid the use of expensive, high-emission peaking power plants. They can shift computational loads to times of lower electricity demand and prices, flattening the demand curve and increasing grid utilization. AI data centers can also increase energy use during renewable energy surpluses, balancing intermittent sources and reducing the need for costly energy storage solutions. Additionally, they can mobilize their resources (uninterruptible power supply, energy storage, and backup generation) to help prevent power outages, which are becoming an increasingly significant concern due to more frequent extreme weather events, aging infrastructure (much of the U.S. electric grid was built in the 1960s and 1970s,[26] and it will take decades to upgrade the whole grid), and growing power demand.

By providing ancillary services (i.e., crucial functions that help maintain a reliable and stable electricity system) and improving utilization of grid infrastructure (i.e., minimizing or deferring required transmission and distribution buildouts), AI data centers could help lower grid emissions (as less renewable energy is curtailed and fewer peaking power plants are dispatched) and lower utility costs for all customers by avoiding or deferring the costs of grid expansions that are recovered from all ratepayers.

By using advanced controls, optimizing data center operations, and leveraging rapidly advancing AI for load forecasting, data center operators can also reduce data center energy consumption and integrate them with the local grid without sacrificing their computational capacity.

Recommendations for state policymakers and utility regulators

State policymakers and utility regulators can take three key steps to turn data centers into grid and regional assets and attract technology businesses to their regions. We discuss each in more detail below.

- Fill data and knowledge gaps in AI data center design and operation
- Improve AI data centers' energy efficiency and integration with communities and the grid
- Develop policies that transform demand-side strategies

First, fill data and knowledge gaps; encourage data sharing

We cannot manage what we cannot measure. Due to critical data gaps, energy analysts are not sufficiently equipped to provide robust answers to AI data center electricity growth questions.[27] Current data gaps make it impossible to predict data centers' potential value to the grid as assets. AI data centers differ from conventional data centers in three key ways that significantly affect their overall electricity consumption: they require more power, higher rack densities, and more cooling.

AI servers demand more power than traditional servers, primarily due to the inclusion of accelerators—such as graphic processing units or tensor processing units—essential for AI model training and inferencing. An important metric to measure data center energy use is IT rack density, which is the quantity of power consumed by a server rack. IT rack density continues to increase as cloud computing dominates, rising from an average of 4–5 kW/rack a decade ago to 8–10 kW/rack in recent years, with over 20% of data centers operating above 20 kW/rack.[28] AI data centers operate above 30 kW/rack, and emerging designs will require 100 kW/rack.[29]

These rising power demands require more cooling equipment and new cooling technologies and configurations to manage the high concentrations and amounts of waste heat generated. All this cooling will require even more energy. Air cooling, the dominant industry approach, is no longer viable in such power-dense environments.

We need to baseline, measure, and predict each AI data center's energy consumption and usage patterns to transform AI data centers from large energy consumers to active participants in the grid. A study[30] of 13 large global companies, including Amazon, Apple, Google, Meta, Microsoft, Oracle, and Tesla in the United States, found that while 10 disclosed their total company energy use, only 2 reported the total energy use of their data centers. Additionally, 7 companies reported their average power usage effectiveness—a data center energy efficiency metric—at the company level, but only 2 reported it at the individual data center level.

Data transparency and comprehensive data gathering are essential for integrating AI data centers with the power grid. This information will provide crucial insights into the design and operation of AI data centers, power dynamics in AI model training and inference, and spatial and temporal concentration of energy loads. These factors are critical because the location and timing of AI training and usage directly impact energy demand patterns.

To facilitate this transparency, federal policymakers can (1) encourage AI companies to voluntarily share non-sensitive data about their data center operations and energy usage, or (2) implement regulations that require reporting of key energy metrics related to AI data centers before they can be connected to the power grid. Establishing secure platforms for data sharing and creating mechanisms for companies to share aggregated or anonymized data can help address data privacy and intellectual property concerns.

While federally funded or led studies on key energy issues have provided valuable resources for industry and policymakers, a series of one-off reports on the ICT sector is insufficient. The federal government needs to continuously gather reliable data on energy use in the ICT sector. Given the growth of the sector and its deep integration with the economy, it should be treated as a distinct sector, rather than a subset of buildings or industrial energy use. The rising energy demand of data centers is a symptom of the broader challenges posed by ICT demand growth. Moreover, the products and services powered by the ICT sector serve as a grid-edge resource and support a distributed economic model, which requires systematic data gathering and analysis.

Having standards, protocols, and platforms at the national level is particularly crucial for companies operating nationwide, as consistency reduces their compliance costs. The adoption, implementation, and enforcement of these national standards will depend on state policymakers and, in some cases, local governments. Companies' participation in the development of these standards is also essential. Addressing state-specific challenges and local interests during standard development will ultimately lower barriers to adoption.

Second, improve AI data centers' energy efficiency and integration with the grid

We do not know to what extent AI data centers can further reduce and flex their energy use, as data center developers and operators currently lack incentives and policy support. The first step is collaborative research to investigate, assess, and demonstrate this potential by analyzing how AI workloads impact grid stability and identifying strategies for better integration.

The Secretary of Energy Advisory Board recently recommended 18 actions the federal government can take to meet growing power demands reliably and affordably.[31] The Board recommended that the Department of Energy start with three main steps: (1) fund and lead a series of studies on AI data centers' energy use patterns, (2) explore opportunities for demand flexibility in data centers, and (3) demonstrate these capabilities. While swift action from federal legislators and agencies is essential, state and utility policymakers should work with data center developers and operators in their states to develop creative local solutions because there is no one-size-fits-all approach. Regional considerations inspire creativity that turns limitations into strengths.

For instance, while processor manufacturers continue to improve chip efficiency, many GenAI system owners are exploring novel ways to cool the chips, such as liquid cooling to circulate coolant directly to heat-generating components or submerging components in non-conductive liquid. DG Matrix, a startup in the Research Triangle of North Carolina, offers ultra–high power density silicon-carbide power systems for GenAI data centers, achieving 2–5 times higher power density than conventional power supplies and performing at up to 98% efficiency.

There may be opportunities to enhance cooling system efficiency and reduce water consumption through ground-coupled or district energy systems. Meta and Google are exploring solutions that harness clean heat far below the earth's surface in the Rocky Mountains and Nevada, respectively, through partnering with startups like Sage and Fervo Energy.[32] Innovative cooling systems reduce electricity and water use and ambient noise from conventional direct air–cooling systems. Policymakers can set efficiency targets or provide incentives to encourage these innovations.

Additionally, co-locating data centers with controlled environment agriculture, industrial parks, and commercial and residential buildings with heating needs can lead to more efficient use of resources and energy. For example, Amazon's Tallaght data center in Dublin sends its waste heat to adjacent buildings (public schools, commercial buildings, and apartments) through the city's new district heating system, reducing 60% of carbon emissions from those buildings by replacing their individual onsite boilers.[33] Meta and Microsoft are planning similar district heating projects in Denmark and Finland, respectively. At the same time, Amazon's headquarters in Seattle has used excess heat from a data center in the Westin Building Exchange since 2019.

Although the political environment and infrastructure in the United States differ from those in European countries, we can still learn from their experiences and adopt proven technologies through global companies. As natural gas utilities face existential challenges under the pressure to decarbonize, district heating systems present an opportunity to grow new business revenues. The Jamestown Board of Utilities in New York is proposing a project to expand and retool their thermal heating system,[34] and "GeoNetworks" (neighborhood-wide networks of ground source heat pumps) are being piloted in New York and Massachusetts.[35]

However, such synergistic developments are unlikely to occur organically without policy interventions. To facilitate these integrations, policymakers can provide business incentives (e.g., financial or tax incentives to encourage companies to pursue co-location and resource sharing), regulatory support (e.g., streamlined permitting processes, prequalification of sites, and updated zoning laws to accommodate co-location of data centers and other buildings while requiring measures to control ambient noise), and necessary infrastructure upgrades (e.g., investments in power distribution and thermal energy transfer systems to support these integrations). For example, the Danish Government has made it easier for data centers to supply excess heat to district heating systems by allowing direct pricing agreements between heat suppliers and district heating companies.[36] Intentional and facilitated collaboration among data center operators, agricultural businesses, industrial park managers, local governments, and utility companies is also vital. These policy-driven initiatives can help overcome barriers to implementation and promote more sustainable and grid-integrated data center developments.

Third, develop policies to use demand-side strategies in coordination with energy generation and transmission

To meet the growing electricity demands of the ICT sector while advancing states' and companies' clean energy goals, building more clean electricity generation, transmission, and distribution will be essential. But the longer time horizons of these projects, combined with construction delays, require other tools to meet demand over the next several years.

According to Federal Energy Regulatory Commission (FERC) data, as of the end of 2022, over 10,000 active interconnection requests existed in interconnection queues throughout the United States, representing over 2,000 gigawatts of potential generation and storage capacity if those electricity generators are connected to the power grid.[37] Over the last two decades, the time from submitting an interconnection request to achieving commercial operations has roughly doubled.[38] At a recent FERC workshop,[39] FERC Chairman Phillips commented, "*We know right now that the average wait time is over five years for projects to get through the queue*."

In recent decades, demand-side actions, like energy efficiency and demand response programs for buildings and industrial facilities, have effectively helped meet demand growth and keep customer rates affordable. Demand-side measures have also come to the rescue when our country has faced energy crises over the past quarter century. We can draw upon these learnings for guidance to fully utilize demand-side strategies to meet the immediate load growth needs, allow time for more measured planning of other investments, and avoid unintended overbuilding.

Currently, several policy barriers discourage large loads, such as AI data centers, from participating in grid services. For example, in many utility territories, demand charges—a cost based on electricity usage in a very short period, such as 15 minutes or one hour—are imposed on retail consumers based on their highest power demand over a defined period (a month or even a year), regardless of when it occurs. This legacy rate structure from the 19th century was designed to differentiate customers with relatively stable loads over the month (such as industrial loads) from those who used lots of energy in a few hours but much less the rest of the month, which makes them more expensive to serve. However, this rate structure does not incentivize customers like AI data centers and modern industrial facilities to lower their energy consumption when the grid is congested and strained. Moreover, retail customers often lack access to low-cost or no-cost renewable electricity during periods of surplus, which misses the opportunity to leverage large energy consumers' ability to store excess energy behind the meter for the grid. As a result, drawing energy from the grid is likely more cost-effective for data center developers and owners than investing in local storage.

Technologies such as smart meters, load forecasting, real-time feedback, and dynamic controls have emerged to better align consumption with grid conditions and renewable energy availability. Policy reforms are needed to give retail customers greater access to variable pricing that reflects real-time grid conditions. Large consumers should have options to access wholesale markets or special tariffs that offer incentives to adjust their load based on grid conditions and emissions. Achieving these reforms will require collaboration among policymakers and utility regulators across energy generation, transmission, and distribution.

Recommendations for other key stakeholders

The combined challenges of meeting growing data center and clean manufacturing electricity demand require an integrated effort engaging all stakeholders—going beyond actions from policymakers and regulators.

What we need from data centers:

Collaborate with industry to increase chip efficiency and network efficiency; share knowledge of rapidly advancing AI technologies, which will undoubtedly have grid impacts; commit to working with utilities on managing the grid impact of their flexible loads. These actions are equally necessary for new manufacturing facilities experiencing significant demand growth.

What we need from utilities:

Work with data centers, clean manufacturers, and adjacent communities to ensure affordable, reliable electricity service for all customers while committing to working with customers to implement the latest technologies. These technologies should be deployed not only on the utilities' own networks but also at customer sites when expanding grid capacity.

What we need from RTOs/ISOs and their regulators:

Encourage robust planning; remove regulatory hurdles to implementation of innovative solutions; identify policy opportunities to create win-win scenarios that engage multiple customer groups.

Together, we can ensure just and reliable electric services while powering robust economic growth in the industrial and ICT sectors without sacrificing the environment.

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NOVEMBER 2024

REVISED
DECEMBER 6, 2024

BEST PRACTICES IN INTEGRATED RESOURCE PLANNING

A guide for planners developing the electricity resource mix of the future

Synapse Energy Economics, Inc.

BERKELEY LAB

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The report was released November 2024. The report was then rereleased December 6th, 2024, with an updated name for Best Practice 47.

Principal Authors

Synapse Energy Economics
Bruce Biewald
Devi Glick
Shelley Kwok
Kenji Takahashi

Lawrence Berkeley National Laboratory
Juan Pablo Carvallo
Lisa Schwartz

Acknowledgments

The U.S. Department of Energy (DOE) Office of Electricity provided funding for Lawrence Berkeley National Laboratory's work described in this study, and partial funding for Synapse Energy Economics' contributions, under Contract No. DE-AC02-05CH11231. The Energy Foundation provided partial funding for Synapse Energy Economics.

Contributors:
Form Energy
Rachel Wilson

Synapse Energy Economics
Rose Anderson
Bob Fagan
Joe Hittinger
Alice Napoleon
Jack Smith (formerly of Synapse)

University of Texas, Austin
Nina Hebel
Benjamin Leibowicz

The authors thank Joe Paladino, U.S. Department of Energy (DOE) Office of Electricity, for supporting Lawrence Berkeley National Laboratory's contributions to this guide and partially funding contributions by Synapse Energy Economics. We also thank the following individuals for reviewing a draft of the guide. Individuals and affiliations are listed for identification purposes only. Participation as a reviewer does not indicate support for this document in whole or in part.

Natalie Mims Frick, Lawrence Berkeley National Laboratory

Joseph Paladino, DOE Office of Electricity

Paul Spitsen, DOE Office of Energy Efficiency and Renewable Energy

Rodrigo Cejas Goyanes, DTE Energy

Shayla D Manning and Laura Mikulan, DTE Energy

Mike Sontag, Energy and Environmental Economics

Anna Sommer, Energy Futures Group

Ryan Fulleman, Rachel Moglen, and Nidhi Santen, Electric Power Research Institute

Priya Sreedharan and Taylor McNair, GridLab

Jeff Loiter, National Association of Regulatory Utility Commissioners

Elaine Hale, National Renewable Energy Laboratory

JP Batmale and Kim Herb, Oregon Public Utility Commission

Elizabeth Hossner, Kaitryn Olson, Phillip Popoff, Andrea Talty, and Tyler Tobin, Puget Sound Energy

Carl Linvill, Regulatory Assistance Project

Tyler Fitch, RMI

Jeremy Fisher, Sierra Club

Michele Beck, Utah Office of Consumer Services

Kathi Scanlan, Washington Utilities and Transportation Commission

Gwen Farnsworth, Sydney St. Rose-Finear, and Clare Valentine, Western Resource Advocates

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Executive summary

In 2013, Synapse Energy Economics prepared a report on best practices in integrated resource planning (IRP) for electric utilities (Synapse 2013). In the decade since, the U.S. electricity sector has been in transition. Many aging fossil fuel plants retired as operational costs increased and environmental regulations placed pressure on power plant air emissions and water pollutants. Renewable energy resources were deployed at an increasing pace due to declining costs and favorable policies and incentives. Electrification of transportation and buildings, and greater deployment of distributed energy resources, began to impact utility assessments of grid needs.

While electricity loads grew just 2.6 percent between 2014 and 2023, we are now entering a period of projected load growth with rapid expansion of data centers and industrial and manufacturing loads, in addition to increasing loads from electrification. Utilities, regulators, and regional grid operators are wrestling with the challenges this presents in terms of affordability, sustainability, reliability, and resilience.

The trend toward increasing loads coincides with a temporary slowdown in renewable energy deployment as the industry recovers from inflation and supply chain challenges. Some utilities have responded with plans to extend the lives of potentially uneconomic coal plants or add new natural gas assets over the next 5 years, or both. This may extend reliance on resources that many states seek to phase out to achieve decarbonization and other electricity transition goals. At this turning point, robust and forward-thinking IRP is as important as ever to ensure utilities can meet the needs of their customers while continuing to work toward broader commitments utilities have made to communities and regions in which they operate.

This guide updates and expands the recommendations in Synapse's earlier report and outlines IRP best practices for electricity systems undergoing a major transition. The guide is for resource planning professionals and stakeholders involved in resource planning processes. This diverse group of people includes utility personnel tasked with conducting resource planning and making investment decisions, state regulatory commissions that develop planning guidance and oversee the resource planning process, and stakeholders that represent a wide range of interests—utility consumer advocates, environmental groups, industrial customers, local governments, independent power producers, and many others.

Definition: Integrated Resource Plan

An IRP is a power system plan for a vertically integrated electric utility's power system plan for to meeting forecasted electricity demand over a specified future period.

- The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders.
- The objective of an IRP is to demonstrate which resource portfolio —including supply- and demand-side options—is most likely to be optimal in the face of risks and uncertainties.
- IRPs provide information on electricity system costs, risks, reliability, and trends and answer important questions that affect electricity consumers and utility investors.

The recommendations in this guide are informed by our experience working with a variety of these audiences and our extensive review of IRP reports and proceedings. The utility-specific examples we cite throughout this guide serve to illustrate both best practices and shortcomings; they are not endorsements or indictments of specific utilities. Instead, the examples are intended to provide clarity on practices we recommend or discourage. We aim to be comprehensive in the topics we cover and best practices we offer. The best practices we recommend are based on our collective experience; they are not the only reasonable approaches to various aspects of resource planning.

The guide offers 50 best practices across the following components of the IRP process:

- Designing a transparent and inclusive stakeholder engagement process
- Integrating resource adequacy
- Developing robust model inputs
- Designing scenarios and sensitivities
- Running the models
- Evaluating and communicating results
- Integrating IRP processes with other planning processes, procurement, and utility proceedings

Each best practice includes explanations and examples. Some recommended IRP approaches represent current best practice, while others are aspirational for future improvement. The following checklist summarizes all of these recommended practices.

Best Practice Checklist

I. Stakeholder engagement

- **Best Practice 1:** Use an inclusive stakeholder process
- **Best Practice 2:** Engage technical stakeholders in IRP modeling

II. Resource adequacy

- **Best Practice 3:** Link resource adequacy assessments with resource planning
- **Best Practice 4:** Apply consistent accreditation frameworks to all resource types
- **Best Practice 5:** Use a regional perspective to plan for resource adequacy

III. Developing model inputs

- **Best Practice 6:** Use up-to-date inputs and assumptions
- **Best Practice 7:** Recognize historical data limitations

Load Inputs

- **Best Practice 8:** Develop a load forecast for the expected future
- **Best Practice 9:** Incorporate load flexibility into electrification forecasts
- **Best Practice 10:** Plan ahead for large growth
- **Best Practice 11:** Transparently represent distributed generation and storage

Supply-side resource inputs

- **Best Practice 12:** Use accurate assumptions for the costs of new resources
- **Best Practice 13:** Represent the full cost and risk of advanced technologies
- **Best Practice 14:** Include realistic assumptions about resource availability timing, without unnecessary constraints
- **Best Practice 15:** Limit renewable integration cost adders
- **Best Practice 16:** Model all avoidable forward-going resource costs
- **Best Practice 17:** Model battery energy storage options
- **Best Practice 18:** Be consistent in treatment of emerging technologies

Demand-side resource inputs

- **Best Practice 19:** Ensure thoughtful and consistent assumptions for demand-side resources
- **Best Practice 20:** Model and bundle demand-side resources carefully
- **Best Practice 21:** Ensure consistency with IRP scenarios
- **Best Practice 22:** Incorporate all relevant benefits for demand-side resources

Market inputs

- **Best Practice 23:** Use reasonable market interaction assumptions

Fuel and commodity inputs

- **Best Practice 24:** Model fuel supply limitations
- **Best Practice 25:** Evaluate the impacts of gas price volatility and coal supply constraints

Transmission inputs

- **Best Practice 26:** Consider transmission alternatives and infrastructure expansion
- **Best Practice 27:** Properly justify bulk power system interconnection costs and constraints

IV. Designing scenarios and sensitivities

- **Best Practice 28:** Model a base case that allows for easy comparison
- **Best Practice 29:** Design scenarios to evaluate uncertainty and risk
- **Best Practice 30:** Plan for and incorporate important regulatory factors

V. Running the models (and iterating)

- **Best Practice 31:** Thoughtfully select capacity expansion and production cost models
- **Best Practice 32:** Thoughtfully select a geographic model scale
- **Best Practice 33:** Thoughtfully define the appropriate study period
- **Best Practice 34:** Thoughtfully select the appropriate time granularity for production cost modeling
- **Best Practice 35:** Calibrate the production cost and capacity expansion models
- **Best Practice 36:** Let optimization models optimize
- **Best Practice 37:** Base power plant retirement decisions on forward-looking costs
- **Best Practice 38:** Use modeling parameters that capture the value of battery energy storage
- **Best Practice 39:** Use stochastic approaches for robust portfolio creation
- **Best Practice 40:** Use the models iteratively

VI. Evaluating portfolio results and communicating transparently to regulators and stakeholders

- **Best Practice 41:** Use appropriate metrics to evaluate IRP results
- **Best Practice 42:** Report results clearly
- **Best Practice 43:** Benchmark inputs and results to other utilities
- **Best Practice 44:** Select a preferred portfolio
- **Best Practice 45:** Model state goals and priorities in preferred portfolio

VII. Integrating the IRP process with other utility proceedings

- **Best Practice 46:** Use IRP results to inform an Action Plan and utility procurement processes
- **Best Practice 47:** Use IRP results to inform other types of planning
- **Best Practice 48:** Evaluate bill impacts
- **Best Practice 49:** Consider energy justice comprehensively
- **Best Practice 50:** Consider the evolving natural gas distribution industry

Introduction

WHAT IS INTEGRATED RESOURCE PLANNING AND WHY IS IT IMPORTANT?

An integrated resource plan (IRP) is a roadmap for meeting forecasted electricity demand over a specified future period, historically focused on the bulk power system.[1,2] Many vertically integrated utilities in the United States, including investor-owned, municipal, and rural cooperative utilities, conduct IRP processes. Regulated utilities—investor-owned as well as cooperative utilities in some states—file these plans with public utility commissions under state guidance. Other cooperative utilities and municipal utilities submit plans only to their governing boards.

The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders and regulators. The objective of an IRP is to demonstrate which resource portfolio is most likely to be least cost in the face of risks and uncertainties. IRPs provide regulators and stakeholders with information on electric system demand, reliability, costs, risks, and uncertainties and other important issues that affect utility customers.

Robust resource planning is critical for utilities to make investment decisions that are reasonable, prudent, and in the public interest. Poor utility resource investment decisions can burden customers with electricity costs that are higher than necessary, lead to over- or under-procurement of resources, disrupt achievement of state policy goals, and forego solutions to contain costs and risks in the future. Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers, while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.

Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.

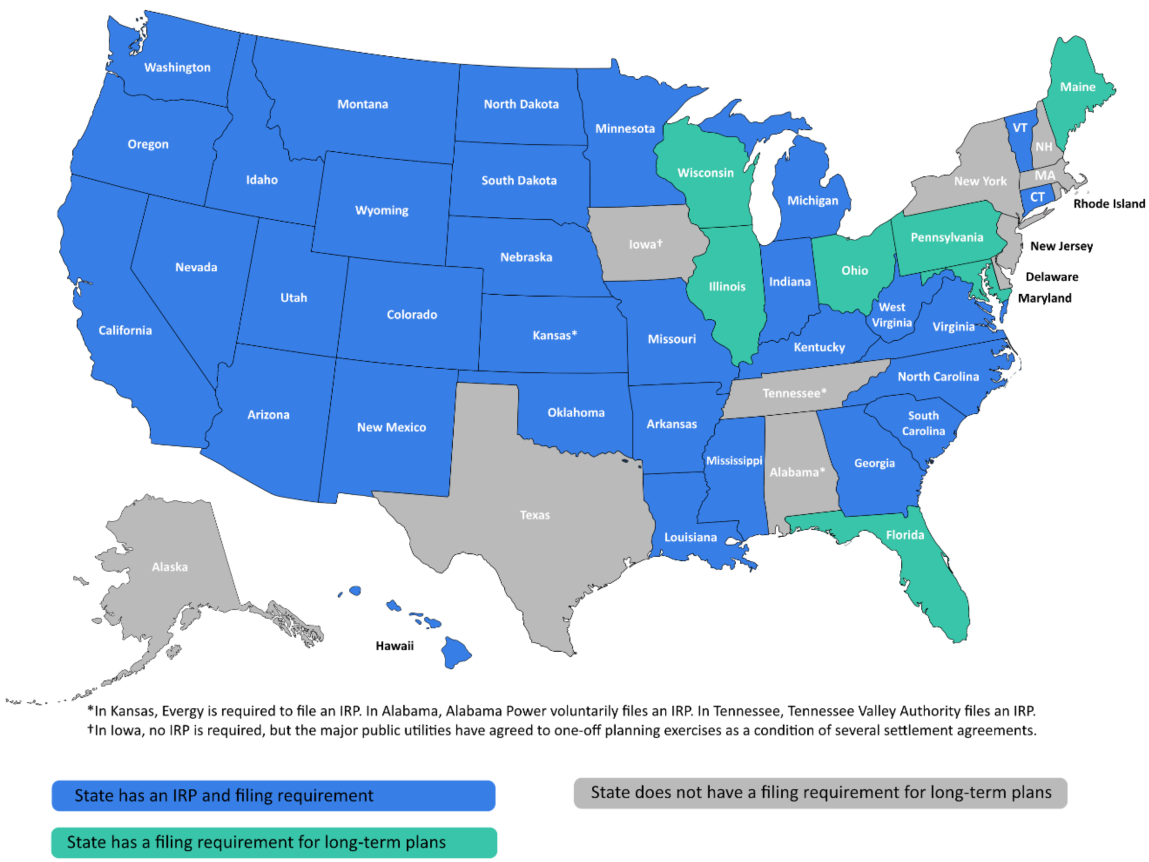
IRP processes emerged from least-cost planning in the late 1980s when concerns over fuel price volatility and bulk power reliability prompted states to require electric utilities to examine prudency and affordability of investments, among other issues. A majority of states today require regulated electric utilities to file IRPs (Figure 1). Some states require utilities to file less comprehensive long-term plans. In Florida, for example, utilities must file Ten Year Site Plans every year, but these plans do not include capacity expansion or optimized portfolio modeling. In addition, some utilities file IRPs to meet requirements of federal power marketing agencies (National Archives, n.d.), and some utilities voluntarily file IRPs. While IRPs are not

[1] Some jurisdictions are implementing or investigating Integrated System Planning approaches. For example, Hawaiian Electric filed its first Integrated Grid Plan in 2023 to harmonize distribution, transmission, and generation planning through iterative modeling. In 2023, Salt River Project in Arizona published its first Integrated System Plan. Public Service of Colorado is working to integrate modeling and planning across electric generation, transmission, and distribution, as well as natural gas. Washington state requires its large dual-fuel utility, Puget Sound Energy, to file an Integrated System Plan by 2027 (RCW 80.86.020(4)).

[2] The electricity industry often uses the term "IRP" to refer to both the resource planning process and the resulting resource plan filing. In this report, "IRP" refers to the plan and "IRP process" describes the process that results in the plan.

required in all states, lessons from quality IRP processes are applicable across all utility planning processes.

Figure 1. States with integrated resource planning or similar processes as of November 2024



An IRP process is also a vehicle for planning, oversight, and feedback. The basic framework is the same across most states: The utility performs modeling and analysis with input from stakeholders and communities, synthesizes the results into a written plan, and submits it to state regulators for review. Utility customers and other stakeholders have an opportunity to provide input, and the utility can move forward with a plan that is informed by stakeholder input and some amount of regulatory review and oversight. The ideal process is one that is mutually beneficial for both the utility and the public.

The rules that govern IRP processes vary by state (RMI 2023). The required filing frequency varies from 1 to 5 years. The planning horizon required for most IRPs spans 10 to 20 years, although some utilities plan out as far as 40 years. Many states require utilities to include a near-term (2 to 5 year) action plan.

Regulatory action from state commissions on IRPs varies, from accepting that the plan meets filing requirements—with any deficiencies noted (e.g., Mississippi), to acknowledging that the plan seems reasonable at the time (e.g., Oregon, Utah), to approving or rejecting the plan (e.g., Colorado, Georgia, Nevada). A commission's decision on the IRP typically carries weight in cost recovery proceedings such as general rate cases that determine the revenue the utility may collect through customers' electricity rates.

In some states, IRP and resource procurement processes are tightly coupled (e.g., Nevada, Colorado, and Minnesota); in other states, they are more distinct processes (LBNL 2021b). Procurement processes can provide current input data for use in IRP modeling. Although an IRP establishes a resource investment plan, real-world changes such as equipment failure, new regulations, and changing market trends often demand adjustments and deviations in resource procurement from what was planned.

Utilities have considerable latitude in the way that they conduct IRP modeling and present results. Further, IRP technical complexity and asymmetries of information make oversight difficult. Nevertheless, state utility regulators and stakeholders can take concrete actions to support IRPs that are consistently well conducted. Enabling such engagement requires that planning processes are transparent and inclusive, state planning objectives are explicit, and utility models and methods are up to date and rigorously applied.

What has changed in the last decade?

Synapse authored a report on IRP best practices in 2013 (Synapse 2013). In the decade that followed, the U.S. electric power landscape changed substantially. This updated and expanded guide addresses a multitude of changes that could lead to a large buildout of the electricity system in the future. The potential for such a buildout places new urgency on the need for quality long-term resource planning. Without quality planning, we risk short-sighted and inefficient investments that impede the optimal buildout of the utility system. Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.

The main drivers of change over the past decade include low natural gas prices, falling prices for renewable and other low-carbon energy resources, significant growth in variable energy resources, advances in generation and grid management technologies, increased use of distributed energy resources for grid services, increasing frequency and severity of extreme weather events, fuel price volatility, inflation and supply chain disruption, interconnection queue challenges, decarbonization goals and targets, and environmental regulations.

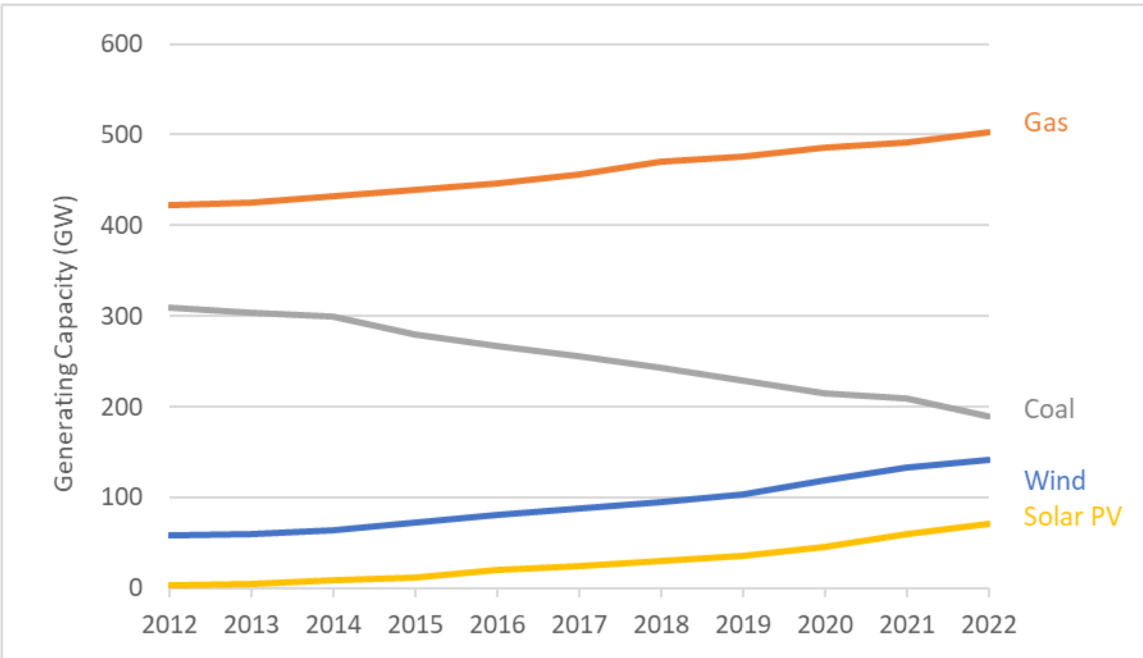
> ***Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.***

Looking forward, we expect to see many of these trends continue. We also expect acceleration of current trends due to electrification of transportation and buildings, growth in data center loads and other end uses driven by artificial intelligence (AI) as well as manufacturing, retirement of coal plants and reduction of coal supply, changing capacity accreditation[3] frameworks for resources, changes in renewable energy prices, integration and interconnection challenges with increased deployment of wind and solar, and development of new carbon-free technologies. In addition, there will always be changes we cannot predict. IRPs can build in flexibility to reevaluate resource acquisition strategies over time and make resource decisions closer in time to projected needs.

[3] Capacity accreditation is the process of measuring and assigning a value to a resource that represents its contribution to resource adequacy and reliability on an electricity system. NERC defines resource adequacy in its Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."

The electricity resource mix has changed dramatically since Synapse's 2013 report (Figure 2). That year, the United States was in the midst of a shale gas revolution that enabled an industry-wide move from coal to gas (U Michigan 2014). Gas, wind, and solar capacity has continued to grow over time, increasing the shift away from coal (U.S. EPA 2022). Until recently, electric utility demand was in a two-decades-long period of relatively flat load growth. In the last decade (2014–2023), electricity demand grew just 2.6 percent (U.S. EIA 2024b).

Figure 2. Utility-scale electric generating capacity for selected resource types in the United States



Source: U.S. Energy Information Administration. 2024. "Sales of Electricity to Ultimate Customer: Total by End-Use Sector, 2014-March 2024," Table 5.1. https://www.eia.gov/electricity/monthly/xls/table_5_01.xlsx.

Technology innovation also has had a significant effect on resource costs over the last decade—for example:

- New renewable energy technologies and economies of scale have reduced the cost of wind and solar precipitously. They are now often the least expensive new resources available on a per megawatt-hour (MWh) of energy basis (NREL 2021a). In 2022, renewable power generation exceeded coal generation for the first time in U.S. history, and renewable resources now produce 21 percent of annual generation (U.S. EIA 2023c).
- Utilities are deploying cost-competitive utility-scale batteries across the country to help meet peak demand, mitigate short-term changes in solar and wind supply, and provide ancillary services (Martucci 2024).
- Grid modernization advancements, such as advanced metering infrastructure paired with time-varying rates and control technologies, microgrids, and distributed generation and storage, have increased visibility into and management of end-use energy consumption, providing utility

customers with new opportunities for demand flexibility to reduce energy bills and provide grid services (Deloitte 2022).

Federal and state policies and regulations also affect the resource mix. For example, the *Inflation Reduction Act of 2022* (IRA) introduced multiple federal incentives to modernize and decarbonize the electric grid. In another example, the Federal Energy Regulatory Commission (FERC) Order 1920 is intended in part to ease access to remote, low-cost resources such as wind and solar. In addition, large utility customers in the private and government sectors are increasingly purchasing low-carbon energy resources, and many utilities are integrating corporate decarbonization goals into their planning processes (LBNL 2019a).

These advances appear against a backdrop of new challenges (EPRI 2023b):

- The interconnection queue for new resources has grown tremendously, creating a deployment bottleneck and slowing down the pace of deployment of new wind and solar resources in many regions (LBNL 2023d).
- Inflation, tariffs, and supply chain challenges stemming from the COVID-19 pandemic disrupted the steady downward trend in renewable energy costs and created a relatively short-term period of stagnation in price decline trends (LBNL 2023c).
- Extreme weather events driven by climate change, including extreme heat, severe and prolonged cold snaps, raging storms, and wildfires, have revealed the fragility of power grids and prompted new efforts by utilities to better understand resource adequacy needs to boost resilience and improve capacity accreditation methods (FERC 2023).
- A rapid rise in data center load growth driven by AI and an increase in industrial and manufacturing investments add risks for resource planning (Grid Strategies 2023). Coupled with trends in electric vehicle (EV) adoption, building electrification, and integration of planning across the bulk power and distribution systems, utilities are facing a new paradigm for planning (IEA 2024; NREL 2021b).
- Retirements of coal units are accelerating along with deployment of renewable energy, driven in part by state and federal environmental regulations and incentives (S&P Global, n.d.). This creates new challenges for reliability and grid planning and requires increased investment in transmission, firm flexible resources (such as battery storage), and grid management technologies.

Age-old challenges also continue in new contexts. For example, Americans have weathered multiple periods of fossil fuel price shocks. Most recently, the 2022 Russian invasion of Ukraine impacted gas supply and prices (Maneejuk, Kaewtathip, and Yamaka 2024). The domestic coal industry has wrestled with dwindling demand, labor challenges for mines and transportation, and constriction and consolidation of coal supply ownership (PA Consulting 2023). Such challenges highlight the importance of understanding risks associated with fuel price volatility (Amy 2023a) and spending large amounts of capital to maintain aging, potentially uneconomic power assets (EIPT 2023). Another challenge is the cost of new infrastructure that may be needed for fuel delivery and storage. These issues underscore the importance of robustly evaluating the economics of retirement and replacement of legacy generating units.

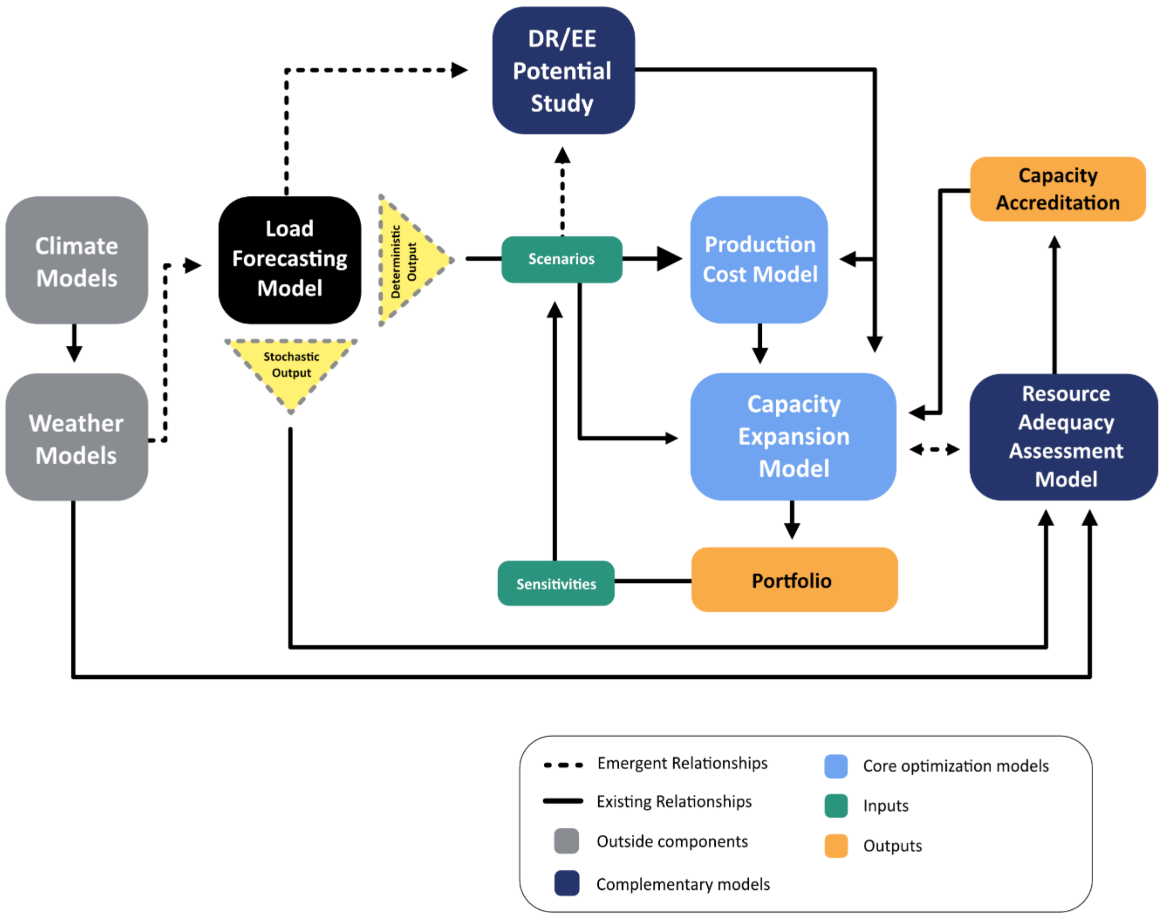
Thoughtful and robust long-term planning is needed more than ever. In this moment of rapid, widespread changes affecting both supply- and demand-side resources, the planning tools and strategies of the past do not match the scale and pace of today's needs. Emerging best planning practices can help tackle these challenges by providing a wide range of tools for navigating this transition and positioning utilities to evolve and adapt as energy systems and markets continue to change.

The role of modeling in IRP

Modeling is a core tool of the IRP process that informs utility planning decisions. To achieve multiple planning objectives, the utility can choose the most appropriate models and run them with accurate and transparent inputs. At the same time, some input data may be sensitive to the company's confidential business strategy or financial decisions. Planners can pair modeling tools with rigorous analysis, critical thinking, and creativity, using judgment and good sense throughout the modeling process.

IRP processes use many types of models to generate different types of forecasts. Figure 3 illustrates a typical IRP modeling structure. Planners conduct separate studies when necessary to generate forecasts, which become key input parameters into other models. For example, one model may forecast fuel prices or new resource costs, which may in turn feed into models that simulate generation unit economics. Reliability modeling helps to determine the reserve margin and other reliability metrics that a utility must meet and to assess capacity accreditation for different resource types. Planners may use additional models to determine key input parameters such as potential and costs for energy efficiency and demand response resources.

Figure 3. Example of a typical model structure used in IRP processes and current (solid line) and potential (dashed line) interdependence



Note: DR refers to demand response. EE refers to energy efficiency.

Descriptions of modeling in this guide primarily focus on capacity expansion and production cost modeling, which lie at the center of the modern IRP process. These two techno-economic modeling steps are increasingly integrated and performed in an iterative manner. Integration of these models with resource adequacy assessment models is an aspirational practice to develop robust least-cost portfolios.

The capacity expansion model simulates the current system, then determines the optimal, least-cost schedule to retire, build, and run generation and storage units as well as demand-side resources. These decisions usually occur on an annual basis. This first model is called “capacity expansion” because the model can add new resources and retire existing ones. The goal of the model is to build a least-cost system that meets projected loads, subject to reliability constraints and policy requirements such as state renewable portfolio standards.

The production cost model optimizes a candidate resource portfolio for least-cost operations, capturing economic dispatch, unit commitment, ancillary service requirements, and other technical constraints at an hourly or sub-hourly basis. This simulation of the economic operation of the power system is often much more temporally and spatially detailed than simulation by the capacity expansion model.

Production cost modeling provides detailed results on system cost, operations, emissions, variable energy curtailment, and other key metrics and outputs.

At its core, capacity expansion and production cost modeling are about minimizing system costs subject to constraints. The extent to which a modeler allows the model to optimize, and the information the modeler feeds the model for that purpose, are critical for achieving useful IRP results.

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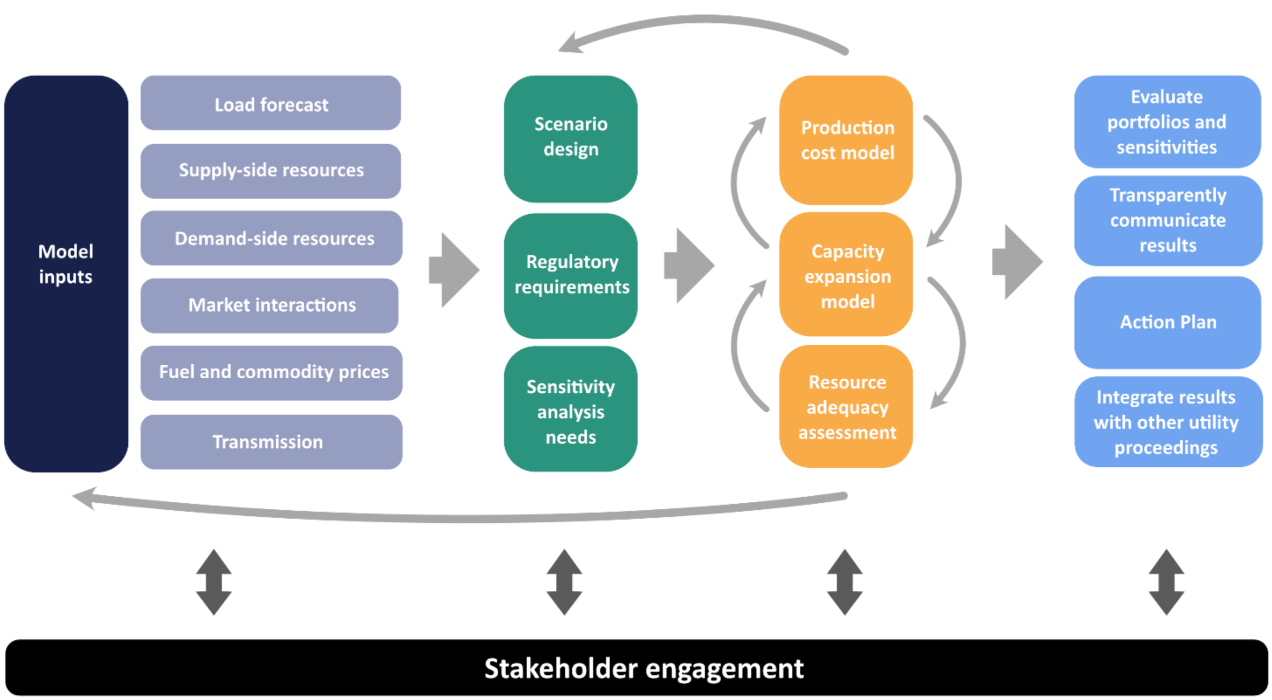
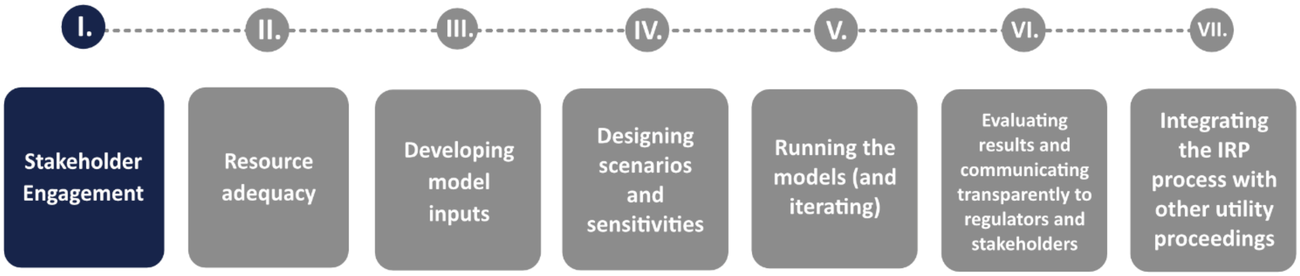
Overview of Report

The rest of this guide describes both current and emerging best practices in IRP. The guide mirrors the order of a typical IRP process. Figure 4 depicts the typical IRP process flow, including how modeling interacts with other steps of the process, such as stakeholder engagement. The report begins by outlining the requirements for a robust stakeholder engagement process. We then summarize best practices for integrating resource adequacy into IRPs. Next, we present best practices related to developing robust model inputs, designing scenarios and sensitivities, and running the model. Then, we discuss how to evaluate and communicate portfolio results. We end with a discussion of how to integrate IRP processes with other utility planning processes and proceedings.

Figure 4. Typical IRP process flow diagram



I. Stakeholder engagement



The first two best practices in this guide focus on how to engage stakeholders in the IRP process. We provide suggestions for making the process inclusive for a wide audience as well as ensuring that technical stakeholders have the tools necessary to participate in the modeling process.

Best Practice 1. Use an inclusive stakeholder process

Develop an inclusive stakeholder engagement process that balances access and transparency with reasonable time commitments.

Vertically integrated electric utilities provide essential energy and delivery services to a captive customer base through a monopoly business model, while operating in a highly technical and complex field. To ensure that utility decisions are fair and robust and based on reasonable evidence, meaningful stakeholder engagement (RMI 2023), regulatory oversight, and participation of technical experts working on behalf of stakeholders are essential in the IRP development process. A well-developed stakeholder engagement process provides access to all stakeholders who have a reasonable interest and stake in the utility decision-making process— including those who have traditionally been underrepresented in these processes.

An effective IRP process includes regular stakeholder meetings that allow participation and engagement throughout the IRP process, from input development through scenario development and modeling, review of results, selection of the preferred portfolio, and development of the action plan. The utility engages stakeholders early in the process, on a timeline and in a manner that allows for meaningful feedback. The following elements represent a set of minimum practices for an effective stakeholder engagement process:

Process and design elements

- The utility develops a charter or document clearly outlining the rules, norms, and any other relevant details for the stakeholder engagement process, with buy-in from stakeholders to align expectations for all parties.
- Facilitators, technical consultants, or an internal communications team moderate stakeholder sessions and technical conferences.

- Materials, including an agenda and slides to be presented, are available in advance of each stakeholder meeting and technical conference so stakeholders have time to review the information, prepare for planned topics, and provide productive input.
- A formal discovery process allows stakeholders access to data, assumptions, results, and any other information that the utility does not directly offer.
- The process elicits stakeholder feedback during stakeholder meetings and technical conferences, as well as through a formal commenting process, with clear deadlines for providing input.
- Utilities provide formal responses to stakeholder feedback, adhering to clear deadlines for responding to stakeholder comments. Responses clearly address which feedback is being adopted and how, and which is not and why.

Removing barriers to participation

- Stakeholder sessions accommodate remote access to enable as many stakeholders as possible to participate, including members of the public and underrepresented groups.
- The stakeholder process design considers and accommodates stakeholders' needs and challenges such as language, schedules, and economic barriers.
- Technical education sessions, offered and open to all, provide core education on the IRP process (as needed/requested by stakeholders).
- Stakeholder sessions occur regularly enough to allow for meaningful input and participation throughout the development of the IRP, without being so time-intensive and burdensome that only a handful of people can fully participate.
- Intervenor compensation funds designate and otherwise approve stakeholders to formally participate in public utility commission (PUC) proceedings, addressing barriers to participation and engagement of technical experts for many stakeholders. Such funding typically requires action by state legislatures and utility regulators.

Transparency

- The IRP process engages stakeholders throughout, including:
    - Before modeling begins to propose scenarios and inputs and provide feedback on what is being modeled and how;
    - During modeling to provide input on results; and
    - After the draft plan is released to provide input on how the utility used the results to create an action plan.
- Transparency is a priority, with the utility sharing all input data, modeling assumptions, scenario and sensitivity designs,[4] modeling files, and modeling results as they become available–as well as any other information necessary for stakeholders to have a comprehensive understanding of how the IRP was developed. This may include sharing utility spreadsheets used for pre-

[4] As discussed in Section VI, a scenario is a model run with a specific set of input assumptions and constraints. A sensitivity changes a single key input to understand how that input affects or drives results, often across multiple scenarios.

processing of data and post-processing of results so stakeholders can see how the utility used both input and outputs.

- The utility shares data, inputs, and results for its preferred portfolio and all major scenarios and sensitivities–not just for one base scenario.[5]
- The utility only requires non-disclosure agreements (NDA) when necessary to protect data that is truly a utility trade secret or that the utility holds under a third-party NDA (e.g., fuel and market price forecasts) to avoid unnecessarily hindering stakeholder engagement.[6]

Technical engagement

- The process allows stakeholder-funded technical experts to participate and contribute essential technical expertise.
- The process includes technical IRP sessions, open to all stakeholders, to allow for additional expert input on specific topics, beyond what may be provided in public meetings.
- Technical experts have access to review all inputs, outputs, modeling files and can gain access to the modeling software the utilities used (as discussed in Best Practice 2).

If utilities are unable to meet any of these elements, they can make appropriate efforts to retroactively ensure stakeholders have an opportunity to give productive input.

There are many examples of public utility commissions and utilities implementing the practices noted above. For instance, in 2022 the New Mexico Public Regulation Commission established new rules that promote engagement and transparency in IRP processes for the state's investor-owned electric utilities. The rules require the utilities to use a facilitated stakeholder process and provide stakeholders with reasonable access to modeling software, perform a reasonable number of modeling runs, and share all modeling information (Gridworks 2024).

As another example, in 2018 the Hawaii Public Utilities Commission ordered Hawaiian Electric Companies to develop a workplan that comprehensively describes the timing and scope of major activities that will occur in the integrated grid planning (IGP) process (HI PUC 2018). The workplan describes the following: (1) the proposed working groups, including specific objectives, composition, expected deliverables, and timelines; (2) a proposal for how forecasting assumptions, system data, modeling inputs, studies, analyses, meeting summaries, and other data will be shared with the PUC and community members throughout the IGP process; (3) processes and timelines to define and quantify system needs; (4) processes and timelines to procure solutions to meet grid needs and to optimize the solutions; (5) opportunities for midstream evaluation and updates; and (6) the role of independent facilitation in assisting the IGP process.

[5] As discussed in Section VI, a utility identifies a preferred portfolio after reviewing the results of the modeling analysis. This collection of resource builds and retirements reflects the utility's short- and long-term resource plans.
[6] IRPs provide a framework to inform utility resource solicitations and specific resource commitments. Overuse of protective agreements and redactions in an IRP can hinder stakeholder engagement in those processes.

Best Practice 2. Engage technical stakeholders in IRP modeling

Provide modeling files and other necessary information to technical stakeholders to allow them to replicate modeling outcomes from the IRP and develop alternative portfolios.

Utility IRP modeling is generally conducted using sophisticated and proprietary capacity expansion and production cost modeling software. The software is largely inaccessible to stakeholders, challenging their role in supporting regulatory oversight. Often, PUC staff are not trained in utility modeling software, so they cannot ensure that utilities conducted modeling reasonably and prudently. However, technical stakeholders with modeling expertise and access to data can verify and validate utility outcomes and findings. They can independently test utility assumptions, identify refinements and improvements, and bring additional technical knowledge to IRP proceedings. Such contributions by stakeholders are valuable even in states where PUC staff are more engaged in IRP modeling. Stakeholders can also model alternative portfolios that use the same, or a similar, modeling framework as the utility. The commission would not have such information in the absence of technical intervenor participation.

The following is necessary to enable technical intervenors to participate in the modeling process:

- Modeling software licenses, paid for by the utility, for all technically sophisticated stakeholders with the ability to review the modeling files or perform their own modeling runs
- Input data, model settings and constraints, and output data for the reference portfolio and preferred portfolio as well as all major scenarios presented in the IRP
- Modeling files and data that match what the utility is using so that intervenors are able to replicate the utility's modeling outcomes as a starting point and calibration step for their own modeling exercises
- Explanations of how the utility used input data and values, how it derived inputs, and what steps the utility took to develop portfolios and results
- Utility spreadsheets used for pre-processing of data and post-processing of results so stakeholders can see any modifications used to develop model input streams and convert outputs to revenue requirement results
- Documentation for supplemental analysis the utility used to develop inputs, such as reserve margin or effective load-carrying capability (ELCC), that it developed externally or outside the model.

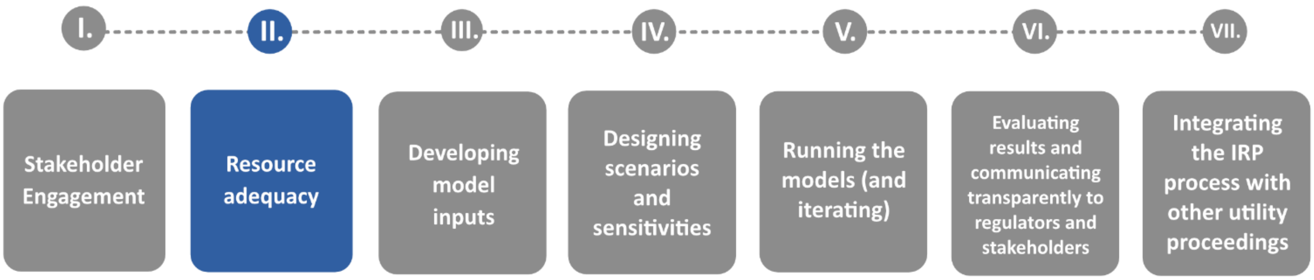
Definition: Effective load-carrying capability

The ELCC of a resource or portfolio of resources represents the amount of dependable capacity the resource can provide.

For example, as part of the Arizona Public Service (APS) 2023 IRP process, the commission required the utility to provide intervenors with licenses for the Aurora model, utility modeling files, and trainings with the model developer as well as access to resources (ACC 2022). This allowed stakeholders to carry out their own modeling.[7] In Iowa, as part of two settlement agreements, MidAmerican Energy Company and Interstate Power and Light agreed to provide intervenors with model licenses as part of the Renewable Energy Study docket (MEC 2022a). In Michigan, DTE and Consumers Energy also agreed voluntarily to provide modeling licenses to stakeholders as part of the IRP process.

[7] However, the utility did not provide the modeling files for all of its scenarios, limiting stakeholders' ability to validate the company's modeling results for its preferred portfolio and scenarios.

II. Resource adequacy



IRP capacity expansion models are designed to optimize resource build and retirement decisions while maintaining an acceptable level of system reliability and meeting policy requirements. These models typically represent system reliability using a planning reserve margin, which denotes the energy capacity in excess of the forecasted peak load that the utility needs to serve in order to maintain the desired level of reliability. The required reserve margin creates a buffer to protect the system from load forecasting uncertainty and factors that could unexpectedly influence supply or demand. Such factors include unplanned unit outages, generation or transmission contingencies affecting energy supply, and extreme weather events.

Traditionally, resource planners used an annual planning reserve margin and designed their systems to ensure that they could meet demand on the single annual hour of peak demand. Planners would calculate the annual planning reserve margin necessary to achieve target levels of system outages and calculate a firm capacity rating for each resource based on its expected availability at peak. Then, they would run their capacity expansion model to optimize resource build and retirement decisions based on the annual planning reserve margin constraints. There was limited iteration.

This construct worked relatively well when resource availability[8] was relatively uniform year-round,[9] nearly all system resources were dispatchable, and peak demand was substantially larger during one season. But planners can no longer universally assume any of these things to be true, particularly as renewable energy sources and storage make up a larger portion of the resource mix. Planning for times with low resource availability can be as important as planning for times with peak system demand. This planning is most effectively done by evaluating system needs and resource contributions through a coordinated and iterative resource adequacy assessment.

Resource adequacy is defined by Electric Power Research Institute (EPRI) as an assessment of whether the current, or projected, resource mix is sufficient to meet capacity and energy needs for a particular grid (EPRI n.d.). Validation of resource adequacy is a critical and integral part of resource planning. Ultimately, best practices in resource adequacy are not about developing robust static metrics, but rather developing an iterative process for establishing system need, valuing resource contribution to system

[8] Here we refer to resource availability generally as the megawatts (MW) of capacity a resource can provide to the grid based on its own inherent characteristics and limitations, as well as external conditions that impact operations.
[9] With small deviations for steam unit performance based on temperature.

need, and testing how well a resulting portfolio meets system needs. However, in the absence of an iterative modeling process, development of a robust reserve margin is essential.

This section of the report introduces foundational best practices for addressing resource adequacy in IRPs. Recognizing the complexity of the issue, the variety of approaches available, and work by many others in the field, we recommend that resource planners use our best practices as a baseline and screen. Figure 5 provides resources (linked) developed by Energy Systems Integration Group (ESIG), EPRI, and other leading experts in the field that offer more detailed discussion on resource adequacy principles and specific implementation guidance.

Figure 5. Resources on resource adequacy principles and specific implementation guidance—click to view

- Linking Capacity Expansion, Resource Adequacy, and Production Cost Modeling Tools for Integrated Strategic System Planning. (Electric Power Research Institute 2024)
- Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. (Energy Systems Integration Group 2023)
- New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements. (Energy Systems Integration Group 2024)
- Redefining Resource Adequacy for Modern Power Systems. A Report of the Redefining Resource Adequacy Task Force. (Energy Systems Integration Group 2021)
- Lawrence Berkeley National Laboratory: A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems. (Carvallo et al. 2023)

We discuss three best practices in this guide related to resource adequacy: (1) integrating resource adequacy analysis, resource planning analysis, and development of robust reserve margins; (2) aligning resource accreditation with realistic expectations of resource availability and applying constructs uniformly across resource types; and (3) taking a regional perspective on resource adequacy.

Looking Ahead: Link frameworks for developing reserve margins and resource capacity accreditation

Looking to the future, the framework for developing the reserve margin and the framework for calculating resource capacity accreditation need to evolve together, as the two are inherently linked.

Best Practice 3. Link resource adequacy assessments with resource planning

Conduct resource adequacy assessments and resource planning analysis in a coordinated and iterative manner.

Linking resource adequacy assessments with resource planning in an iterative manner generally starts with stochastic modeling[10] to develop a reserve margin that reflects reliability standards and requirements and preferences.[11] Planners then use the reserve margin in the resource planning model to develop an optimized resource plan. The resulting resource plan is then tested in the resource adequacy model to ensure that the plan still meets system reliability requirements, or that it does not exceed them significantly (since overly adequate systems have higher cost). Iterations continue on the reserve margin and resource portfolio until the modeling develops an optimized resource plan that meets the reliability standard. In practice, it is not essential to develop a precise reserve margin when resource adequacy modeling is being used to validate portfolio performance. In such cases, utilities can choose a reasonable starting value and iterate as necessary.

In PNM's 2020 IRP, for example, the utility used SERVM to develop the planning reserve margin requirement needed to meet a loss-of-load expectation (LOLE) standard of 0.2 days per year as well as to validate that the IRP portfolios met or exceeded this resource adequacy standard (E3 and Astrape 2022). While this type of iterative modeling is the best practice, it is time- and resource-intensive. For IRP processes that do not use resource adequacy modeling to validate portfolio performance, development of a robust reserve margin upfront is essential.

Planners typically calculate reserve margins and other resource adequacy metrics through separate modeling exercises conducted prior to IRP modeling. Utilities operating outside of centrally organized wholesale electricity markets are responsible for calculating their own resource adequacy metrics. In regions with organized regional transmission operator (RTO) or independent system operator (ISO) markets, the grid operator generally conducts extensive resource adequacy analysis, and utilities adopt the RTO or ISO values rather than conduct their own analysis. In the Midcontinent Independent System Operator (MISO) market, for example, the market operator released a seasonal capacity accreditation framework applicable to all utilities within the market. Utilities such as Ameren Missouri internalize MISO's planning reserve margin (Ameren Missouri 2023b).

Critically, planning reserve margin and capacity accreditation frameworks need synchronization. If the utility is using a reserve margin differentiated by season, it must also value the capacity accreditation of resources differently by season. Calculations of capacity accreditation values for individual resources occur through similar, but separate, resource adequacy analysis (as discussed in detail in the next section). The framework for developing the planning reserve margin and the framework for calculating resource capacity accreditation ultimately need to evolve together, as the two are inherently linked.

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[10] Stochastic modeling accounts for uncertainty by performing a range of simulated futures and accounting for the probability of that future occurring.

[11] Reserve margins are developed to achieve a reliability benchmark, such as a maximum number of expected hours with outages per year (e.g., a 1-day-in-10-years loss of load expectation).

Planners conduct reliability analysis using stochastic techniques coupled with Monte Carlo analysis[12] to determine how a given reserve margin, portfolio, or resource meets reliability requirements. Stochastic analysis relies on large quantities of weather data that contains both normal and extreme weather events to test performance under a wide range of circumstances. Typically, planners use historical data, although some utilities are switching to use climate change forecast data instead.[13] There are limitations for planners to consider when using historical data for calibration and characterizing stress events, due to increased frequency and severity of extreme weather events as well as accelerating electrification, manufacturing, and data center loads—which may not be reflected in historical load. Forward-looking, synthetic data also has limitations, mainly related to availability and judging its veracity. An example of a utility that has conducted a separate, stochastic modeling study to develop a planning reserve margin and assess resource adequacy is Public Service Company of Colorado (Astrapé Consulting 2021).

Resource adequacy analysis can test variations in a discrete number of factors such as load and outage rates. Modeling runs typically focus on a single study year at a time and identify the time periods with the highest LOLE. The resulting hundreds to thousands of iterations for each study year determine the likely performance of an entire system with a given portfolio. The required planning reserve margin may differ by year based on the available capacity mix from utility-owned and -procured resources, as well as from the market, and the outage rates of capacity resources for that given year, for example. Because a utility conducts resource adequacy analysis for a single study year, when it is validating the resource adequacy performance of a portfolio, it would ideally repeat the modeling for years in which the utility expects large changes in the system. Some utilities perform the additional step of evaluating the cost to the system of different reserve margin levels above the minimum required to achieve the reliability target (such as the 1-in-10-year LOLE). For example, Georgia Power included an economic and reliability study of the target reserve margin as part of its 2022 IRP filing (GPC 2022).

Best Practice 4. Apply consistent accreditation frameworks to all resource types

Credit all resource types in a fair and consistent manner, and clearly align reliability modeling with realistic expectations of resource availability.

The current best practice for capacity accreditation is to use stochastic modeling to conduct an ELCC study for each resource type. A consistent methodology to accredit resources can ensure all resource types are treated in a fair and non-discriminatory manner. The ELCC of a resource represents the amount of incremental dependable capacity the resource can provide to the system. The first step is evaluating how much additional load can be served on the utility system with the addition of a set quantity of a specific resource type, while maintaining the same level of reliability. Planners then calculate the ELCC by dividing incremental peak load served by the nameplate capacity of the added resource. The result is a marginal ELCC which reflects the incremental capacity contribution of the next megawatt of a given resource and an average ELCC which measures the aggregate or portfolio reliability impact of the

[12] Monte Carlo is an analysis technique used to predict the probability of different possible outcomes in the face of uncertainty. The analysis uses historical data to predict a range of future outcomes.
[13] Historical data is likely still the best source for calibration purposes, but it is important to be aware of its limitations.

resource across all megawatts (not just the next megawatt) or across a specific tranche of capacity. ELCC studies are complex, data- and time-intensive, and resource-specific. As discussed above, many RTOs and ISOs conduct their own ELCC studies which utilities can, and sometimes even must, apply to their own footprints (LBNL 2021c). Utilities that do not operate in RTO/ISO regions generally perform ELCC analysis in a modeling exercise separate from the IRP process.

Some utilities do not have time or resources to conduct their own studies for every resource considered. It is critical to avoid over-simplified assumptions that systematically disadvantage certain resource types. For example, if the utility performs a study of the ELCC for a 4-hour battery energy storage system, it cannot assume that the ELCC for an 8-hour system would be the same. Instead, the utility can look to studies from regionally comparable utilities and rely on their calculations, with reasonable and well-justified and documented adjustments as necessary, to account for differences across the utilities.

It is critical for utilities to avoid over-simplified assumptions that systematically disadvantage certain resource types.

Over the past decade, there has been considerable attention on calculating the ELCC for wind and solar and battery energy storage systems (BESS). There has been more limited attention on whether the traditional methods still used to value firm capacity for conventional thermal resources (such as coal, gas, or oil) — the Equivalent Forced Outage Rate Demand, or EFORd, methodologies — still result in sufficient resource adequacy. As the grid evolves, these traditional methods will not be sufficient.

EFORd-based methodologies value a resource's capacity based on the unit's historical outage rates at times it was needed. This means that modeling of fossil fuel resources usually uses average forced outage rates rather than weather-dependent forced outage rates, underrepresenting outage risk in periods of extreme weather. Recent high-profile extreme weather events, including Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, highlight the risks of availability of traditional fossil fuel resources and correlated outages within a given power class of assets (e.g., natural gas) not captured by traditional capacity accreditation methodologies (S. Murphy, Sowell, and Apt 2019). These traditional methodologies (generally determined by RTOs) systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent by failing to account for outage variability, correlated outages, weather-dependent outages, and fuel supply constraints (AEE 2022; Astrapé Consulting 2022).

When viewed together, the use of the EFORd method for thermal resources and ELCC method for wind and solar is concerning:

- The EFORd methodology over-accredits capacity value for thermal resources.
- Utility customers are therefore paying for some level of capacity and reliability services from thermal resources that they do not actually provide.
- Wind and solar resources are being held to a higher standard with the ELCC methodology, resulting in systematic discrimination against them.

Traditional capacity accreditation methodologies have been found to systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent.

As discussed above, the best practice is to apply the same accreditation methodology to all resources. In this case, that is using the ELCC methodology to calculate firm capacity for all resources, including thermal resources. PJM, the ISO/RTO for the mid-Atlantic region, is following that principle.

If ELCC analysis is not available, an alternative is to develop downward adjustments to EFORd-based capacity ratings using actual unit performance during historical scarcity hours. These adjustments can account for undercounted outage risks, including fuel supply contracts, unit age, and extreme weather risks. Additionally, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Using more accurate thermal capacity accreditation increases system resource adequacy by realigning incentives for utilities to improve the outage rates of thermal resources while addressing the systematic disadvantage faced by wind and solar resources.

Best Practice 5. Use a regional perspective to plan for resource adequacy

Align resource adequacy and resource planning with the larger region and market, when applicable, to more accurately capture regional interactions and impacts.

Resource adequacy planning requires a regional perspective to ensure requirements are sufficient without being overly conservative and unnecessarily costly. Utilities that operate within regional markets generally align their reserve margin construct and resource accreditation framework with methods used by the market operators. For utilities not in an RTO, the best option is using resource adequacy studies for the larger region in which the utility operates (e.g., Puget Sound Energy and PNM). Modeling a utility footprint as an island may simplify the modeling exercise, but it is an overly conservative approach that undermines the resource adequacy and portfolio contributions of market transactions (LBNL 2019b) and regional resource diversity.

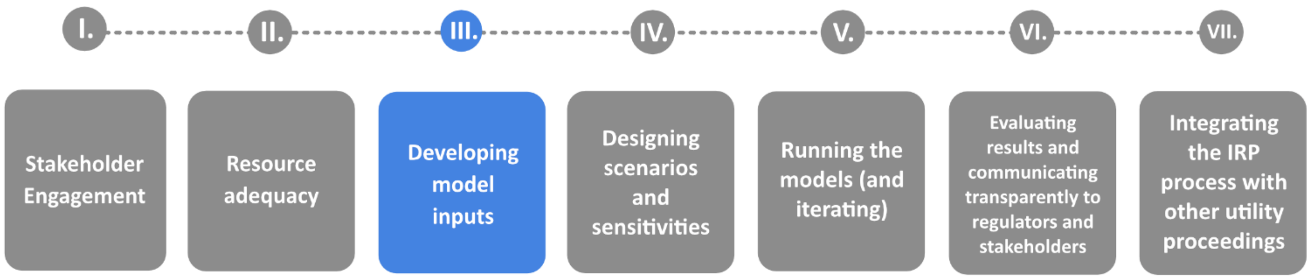
Utilities operating outside RTO/ISO regions, such as those that operate in the Southeast and Western United States, can capture regional benefits by modeling their utility footprint within the larger region in which they operate. This can include reasonable assumptions around the role of market transactions (energy and capacity) based on a realistic view of current procurement in the near term (i.e., how much the utility currently relies on the market) and likely future resource availability later in the study period. To capture the reliability impacts of resource diversity–for example, to understand how wind resources in the larger region can complement solar within the utility footprint–the utility needs up-to-date data on resource plans for other regional utilities. To address uncertainty in both market availability and regional resource development, a best practice is for utilities to model multiple future scenarios that capture different levels of future regional cooperation and resource deployment.

For utilities that operate within an RTO or ISO, market operators conduct resource adequacy evaluations that are inherently regional in scope. Market operators have a variety of unique approaches to address resource adequacy:

- After several years of development, MISO adopted a four-season capacity accreditation construct that breaks down system capacity needs into four time periods during the year.
- PJM recently proposed, and FERC approved, an overhaul of its capacity market. This change increases the accuracy of PJM's accreditation frameworks through the use of marginal ELCC calculations for all resources (new and existing, fossil fuel and renewable), providing greater confidence in reserve margin calculations (FERC ER24-99 n.d.).
- In California, three agencies—the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), and California Energy Commission—have developed a collaborative institutional relationship to ensure that utility-scale resource planning aligns with regional assumptions. CPUC requires load-serving entities such as utilities with loads greater than 700 gigawatt-hours (GWh) to perform IRP processes that adhere to resource adequacy requirements at the state (and ISO/RTO) level. CPUC then reviews the portfolios of each load-serving entity and develops a statewide IRP and preferred portfolio, which is a key input into CAISO's regional transmission planning and regional reliability modeling (CPUC 2016).
- Utilities outside California operating in the Western Interconnect do not have an ISO or RTO. The utilities individually develop reserve margins based on their own analysis of what they need to meet LOLE. The Western Electricity Coordinating Council (WECC) conducts resource adequacy assessments (WECC n.d.) to help these utilities better understand their regional resource adequacy position. Also, many entities in the Western Interconnect are participating in the development of the Western Resource Adequacy Program (WRAP), which assigns planning reserve margins to participants based on regional resource adequacy needs.[14] Additionally, the Southwest Power Pool is pursuing options to expand full regional transmission services to some utilities in the Western Interconnect, and a stakeholder initiative is underway to evaluate what governance and programmatic changes could promote future expansion of CAISO.

[14] WRAP is developing a regional reliability planning and compliance program for Western states to assess and address resource adequacy (Western Powerpool 2023).

III. Developing model inputs



After selecting the appropriate modeling tools and evaluating reliability constraints, planners develop other critical model inputs. Developing input assumptions is ideally an iterative process as subsequent steps of the IRP process reveal new information or guidance. The following best practices guide planners through the various input assumptions, such as load forecasts, demand-side and supply-side resources, and transmission.

Best Practice 6 and Best Practice 7 provide general guidance on developing model inputs. Best Practice 8 through Best Practice 11 discuss load inputs and how to model the changing nature of electric sector demand. Best Practice 12 through Best Practice 18 discuss a wide array of practices and issues associated with supply-side resource modeling. Best Practice 19 through Best Practice 22 discuss how to incorporate energy efficiency and other demand-side resources in IRP modeling. Best Practice 23 provides guidance on modeling market purchases. Best Practice 24 and Best Practice 25 discuss fuel and commodity inputs. Best Practice 26 and Best Practice 27 address transmission modeling inputs.

Best Practice 6. Use up-to-date inputs and assumptions

Use inputs that reflect the most recent available knowledge, grounded in the most recent available historical data and utility-specific studies.

Best practice is to use inputs that reflect the most recent available knowledge, without over-relying on emerging trends that can distort inputs. The typical frequency of IRP filings every 2 to 4 years requires balancing up-to-date inputs with minimizing risks from overstating near-term trends.

A key challenge to using up-to-date inputs and assumptions is planning variables that change while the IRP is under development and forecasts have already been produced and potentially implemented. Rather than continue to rely on a forecast that is directionally wrong (and depending on the stage of the IRP process), an effective IRP process develops a new forecast, waits for development of a new external forecast, or runs a sensitivity analysis using an existing forecast that best represents the current situation. Utilities are not expected to update their models during the IRP process every time something changes. If they did, they would never finish the exercise. Instead, utilities can acknowledge when a change (e.g., commodity or electricity market prices) is significant enough to render modeling results less applicable. If the utility is already too far into the planning process to update base assumptions, best practice is to add sensitivities or scenarios to capture the change (see Best Practice 28 through Best

Practice 30). When significant changes occur, the relative cost of performing additional IRP modeling is minute compared to the scale of investments informed by additional modeling. For example, if an unexpected market condition would lead to reduced natural gas supply and increase in prices, a high short- to medium-term natural gas price sensitivity would be a good option.

Utilities following best practices carefully avoid extrapolating short-term trends over a longer-term period where such assumptions are unsupported. For example, recent supply chain and inflationary pressures resulting from the COVID-19 pandemic caused prices of renewable energy and battery technologies to increase, interrupting a decade of price declines. Some industry sources project this will be a short-term trend and prices will return to previous declining trends (NREL ATB 2024). Yet some utilities have applied this current situation to adopt overly conservative cost decline assumptions for new resources for the entire 10- to 20-year IRP study period (Entergy Arkansas 2024). Adopting conservative cost decline assumptions for all resource types biases modeling results against renewable energy resources, which still are expected to experience technological advances and cost declines relative to more established, conventional technologies. This example illustrates the importance of grounding all assumptions in industry trends and real-world data. When circumstances change, best practice is to add new sensitivities or scenarios to capture the change.

In contrast to temporary price distortions due the recent pandemic, the passage of the IRA provides lasting opportunities that most utilities are just beginning to incorporate into IRPs. According to RMI, of the 50 utilities that filed planning documents between the passage of the IRA and January 2024, "32 percent failed to include IRA provisions in their models, and none adequately considered the IRA's benefits and implications for their systems" (RMI 2024b). It has taken time for the Internal Revenue Service to offer guidance on implementation of many aspects of the IRA, and guidance is still being released (U.S. IRS n.d.). However, many aspects of the IRA that affect fundamental inputs to IRP are now clear and can be internalized in IRP modeling. These include extended and expanded investment and production tax credits for zero-carbon resources and storage, tax credit adders for domestic content and project locations in energy communities,[15] and tax credits for clean hydrogen and carbon capture and storage (CCS).

A final element of this best practice is the treatment of input data that relies on historical records, such as weather data, to train weather-sensitive models or to run resource adequacy assessments. For example, in its 2021 Northwest Power Plan, the Northwest Power and Conservation Council states that the historical weather record does not reflect future weather patterns induced by a changing climate (Northwest Council 2022). The plan implements modeled climate change projections that complement historical data, giving more weight to recent years in the historical record without disregarding the historical variability of weather patterns. PJM's 2023 effort to reform resource accreditation of its capacity market provides another example. PJM explained that its preference was to extend the historical weather data used to calculate gas unit ELCC to between 30 and 50 years, and to use unit operational data from 2012 to the present(PJM Proposal 2023a; Update 2023c; PJM FERC 2023b). PJM

[15] U.S. DOE defines energy communities as (1) brownfield sites, (2) certain metropolitan statistical areas and non-metropolitan statistical areas based on unemployment rates (MSA/non-MSA), or (3) census tracts where a coal mine closed after 1999 or where a coal-fired electric generating unit was retired after 2009 (and directly adjoining census tracts). See https://www.irs.gov/pub/irs-drop/n-24-30.pdf.

also addressed the potential to include climate change adjustments to the historical weather data, as the Northwest Power and Conservation Council is doing.

Best Practice 7. Recognize historical data limitations

Evaluate when the past is a good predictor of the future and when the future is likely to be fundamentally different.

Historical data is useful for calibrating model inputs and sense-checking model results, yet it does not always reflect the future. An emerging example includes observed weather data that is no longer a good predictor of the future due to climate-change-induced patterns and anomalies (see Best Practice 6). Similarly, emerging changes in load composition due to new types of loads, and substitution of fuels for electricity, render load forecasts based on historical data less accurate (see Best Practice 8). Finally, historical generator performance and outage probabilities may not reflect future conditions if units are retrofitted with equipment that improves their resilience.

There are several alternatives to historical data for developing data inputs, as in Best Practice 8 on load forecasting. However, in some cases the use of historical data is needed because it is challenging to produce credible synthetic data or because the data is used in probabilistic analyses such as resource adequacy assessments that require a high volume of actual observations. In these cases, planners can ensure they prioritize the use of more recent data over older data, or conversely reduce the weight of older data that may not reflect current conditions.

A best practice to assess the usefulness of historical data is to perform retrospective analyses of key assumptions, inputs, and forecasts. In its 2021 IRP, Puget Sound Energy devoted an entire section to performing retrospective analysis of previous demand forecasts (PSE 2021). The analysis compares forecasts developed in five previous plans—going back over a decade—with realized values for the forecast variable, adjusting for weather realizations when appropriate (e.g., for the peak demand). The utility developed analyses for electric and natural gas peak demand, housing, and population growth and provided reasons for forecast deviations that could be incorporated in current forecasts. Planners can use this retrospective analysis to inform which historical data is useful on its own, adjustments needed to historical data, or whether historical data does not sufficiently inform future system performance.

Load Inputs

Best Practice 8. Develop a load forecast for the expected future

Develop a load forecast that captures granular temporal and geographic detail, expected future electrification and load growth levels, and decarbonization policies—and that is aligned with current reliability modeling.

Load forecasting is a cornerstone of IRP and one of the key model inputs for production cost, capacity expansion, and reliability models. Electrification of end uses, data center development, and other emerging trends indicate that the era of flat electric load growth is over (Grid Strategies 2023). This section covers best practice in methods, granularity, and characterization of load and its flexibility, considering these trends.

In the past, utilities forecasted annual system-level energy consumption and peak demand, generally split out by customer segment (i.e., residential, commercial, industrial). System operational challenges are prompting a much more granular temporal and spatial resolution to load forecasts that supports similar developments in models (Best Practice 31, Best Practice 32, and Best Practice 33). A best practice is to develop an hourly load forecast that reflects diurnal/nocturnal needs, as well as daily, weekly, and seasonal energy consumption to support a resource portfolio with energy-limited resources such as wind and solar. Several utilities such as PacifiCorp and Puget Sound Energy develop hourly load forecasts for use in production cost models (PSE 2021; PacifiCorp 2023). Similarly, load forecasts that match the model's geographic resolution will better recognize the spatial diversity of load growth and the spatial location of load with respect to transmission infrastructure. PacifiCorp, for example, historically has produced forecasts for the west and east sides of its service territory.

Increasing load from electrification is expected to continue in the coming decades, along with growth of large new loads such as data centers and manufacturing (see Best Practice 10). Forward-looking utilities are striving to properly model electrification and load growth in IRPs to ensure there are adequate resources to meet energy needs (ESIG 2024a). Planners would separately forecast three key electrification variables: (1) adoption of end uses, (2) operation of these end uses, and (3) flexibility potential of such operation. Utilities have historically developed forecasts by customer segment, a practice that can be maintained as it creates a link to the ratemaking process. At the same time, electrification and load growth require an end-use approach. End-use forecasting methods have been used for decades, separately projecting saturation (i.e., customer adoption) and usage intensity for specific residential and commercial end uses (LBNL 2018). This approach is well suited for developing transparent base case and sensitivity load forecasts for emerging end uses such as EVs and heat pumps, and to track specific load growth for data centers, manufacturing, and other industries. Traditional time series-based approaches are insufficient to adequately represent emerging trends. Econometric approaches may be used as a method to predict adoption patterns, as part of an end-use model. An emerging method is propensity of adoption, which leverages machine-learning techniques to determine likelihood of customer adoption based on a wide range of characteristics and drivers (Ratchford and Barnhart 2012). In its 2023 IRP, PacifiCorp developed a propensity of adoption model to predict behind-the-meter PV adoption.

Adoption of new types of electrified end uses and decarbonization policies are tightly linked, although in many cases electrification is an economic decision for customers. The federal government has set several important decarbonization goals, including a 2030, all-sector greenhouse gas reduction target of 50 percent relative to 2005 levels (White House 2021) and securing a 100-percent clean electrical grid by 2035 (U.S. DOE 2023a). Numerous states have promulgated greenhouse gas reduction goals that include electrification, particularly for transportation (C2ES 2024; CESA n.d.). In addition, funding available through IRA supports electrification and decarbonization across the United States (RMI 2024b). A best practice for IRPs is to internalize any state-level electrification goals or electrification impacts of decarbonization policies. An extension of this practice entails running sensitivities that meet federal electrification and decarbonization goals to show the potential impacts of these policies. For example, Public Service Company of New Mexico modeled multiple "futures" in its IRP, including a National Climate Policy future that included high EV adoption and building electrification forecasts (PNM 2023).

Finally, past IRPs have used different statistical properties to reflect variability in their load forecasts. Typically, utilities use a median or 50/50 forecast for energy consumption forecasts and a 90/10 or higher peak demand forecast. The use of a higher percentile as a peak load forecast is not consistent with best practices that link capacity expansion decisions with resource adequacy assessments that ensure the system operates under a prescribed loss of load probability. A best practice is to use median forecasts for energy and peak demand and to let the resource adequacy assessment reflect capacity needs to address stress periods in the grid (see Best Practice 3, Best Practice 4, and Best Practice 5).

Best Practice 9. Incorporate load flexibility into electrification forecasts

Characterize load flexibility operational parameters consistent with electrification forecasts.

Just as important as the magnitude of expected load growth is the shape of new power demand (NREL 2021d). This shape should reflect expected operational profiles for end uses and the flexibility potential of these operational profiles to meet one or more grid services. For example, EVs can achieve a desired state of charge using multiple charging profiles operating independently or in coordination with others. Assumptions about operational charging profiles will have differing impacts on peak load; similarly, assumptions about the willingness or ability of the EV owner to switch and adapt the EV's operational profile captures its flexibility.

Explicit modeling of EVs as a contribution to load is increasingly common, including in IRPs for Puget Sound Energy, DTE Energy, and Entergy Louisiana (PSE 2021; DTE 2022; Entergy Louisiana 2023). Notably, a large portion of this EV load is flexible especially when charging at lower voltage levels for extended periods of time. Different charging incentives can shift EV load to different times of day, and effective planners will model corresponding impacts in the IRP load forecast (Synapse 2020). NorthWestern Energy's 2023 IRP for Montana analyzes potential system and supply benefits of an EV charging management program, though the utility did not integrate the analysis directly into its planning models. Optimized EV charging can add flexibility that improves grid reliability by more effectively using renewable energy, shaving peak electricity demand, and helping maintain power quality (NREL 2021b). The same is true of distributed battery storage systems and demand response linked to newly electrified loads (NREL 2021c; NREL 2021b).

Modeling load flexibility requires using transparent assumptions from reputable studies or models that project time-based load-shifting potential.[16] Preferably, utilities perform or commission their own load flexibility studies and design programs to procure specific amounts of load flexibility identified in the studies. In its 2023 combined Clean Energy Plan and IRP (PGE 2023), for example, Portland General Electric discusses the growing role of flexible loads and describes plans to use findings from

[16] Examples include NREL's EVI-PRO EV infrastructure projection tool, which allows users to develop different load shapes for EVs (NREL EV-Pro n.d.-c) Additional resources to support load forecasting include (NREL and LBNL 2023) and (LBNL 2023b).

implementation of its virtual power plant to inform future modeling of flexible load.[17] Comprehensive IRPs specify plans to achieve the level of load flexibility included in the modeling, including near-term activities in the action plan.

Demand response has been part of IRP for decades. Load flexibility modeling described in this section, however, is an emerging practice with open questions about certain best practice elements. For example, most IRPs that examine load flexibility potential for EVs do so as part of their load forecast and internalize this potential as a load modifier, or as load forecast scenarios. An alternative approach would treat load flexibility as a resource and study it as part of market potential studies traditionally used for demand-side management (DSM) through energy efficiency and demand response programs funded by utility customers (see Best Practice 19 through Best Practice 22). How to incorporate load flexibility in resource adequacy assessments, stochastically characterize flexible end uses, and assess their effective load-carrying capability are emerging issues.

Best Practice 10. Plan ahead for large load growth

Thoughtfully model and plan for the rapid rise of data center, industrial, and manufacturing loads.

Over the past several years, data center load driven by the rise of AI, coupled with increasing manufacturing and industrial load, have become significant drivers of projected future resource needs in jurisdictions across the country, most notably in Arizona, Virginia, Georgia, and Texas (Martine Jenkins and Skok 2024). This new challenge comes as utilities are wrestling with increased load from transportation and building electrification and a changing resource mix as baseload fossil fuel units retire and carbon-free energy resources come online.

The uptick in demand represents a turning point over the previous decade when the United States experienced relatively flat to declining demand growth due in large part to increased DSM and distributed generation deployment (Grid Strategies 2023). Best practices in resource planning will be different for this new era of growth than they were during the past decade. Before utilities build or acquire new resources to meet this new load, there are actions they can take to understand the level of certainty about potential new loads, manage the impact of new loads on system peak, determine the lowest-cost way to meet new loads while maintaining system reliability, and understand the impact of new loads on utility customers and the electricity system broadly. Critically, in this new era of load, customers will be best served if utilities shift from viewing load as a static input to be served in a given year, to viewing the timing of serving load as another decision the resource plan can consider and optimize.

[17] Oregon-regulated utilities also file multi-year flexible load plans with the PUC every 2 years (OR PUC 2020).

The first step for utilities is to determine what level of data center and industrial load is likely to materialize within their service territory. There are varying views on whether future load growth projections for these sectors at large are accurate or overstated. But at the individual utility level, utilities and regulators can take specific measures to avoid building for speculative load and incurring associated costs for all customers:

- Utilities can develop rigorous methodologies for evaluating the likelihood that each potential data center and industrial customer will come online and materialize as actual load. Methods include weighing potential new customers individually based on development milestones, or requiring customers to meet construction and service commitment levels (at which there is a reasonably high level of conversion to actual load) in order to be included in load forecasts. This is especially important given that many companies are looking for the best deal for power and are shopping around their load to multiple utilities. Early-stage negotiations of basic contract terms are insufficient to assume load will materialize. This type of customer-specific load forecasting is not new; utilities have used it to account for large industrial customers in the past. And it can be refined and applied moving forward.
- Utilities can model multiple load scenarios to understand what level of new resources are needed, and which resources are most cost-effective, based on different levels of load achieving commercial operation.
- Regulatory commissions can require utilities to demonstrate that new, large-load customers have reached specific construction milestones before they permit cost recovery of new generation resources built to serve them. In states where Certificates of Public Convenience and Necessity (CPCN) or other forms of pre-approval are required for cost recovery of new assets, commissions can decline to provide pre-approval before new load customers reach certain milestones. In states where pre-approval is not required, in general rate cases the commission can deny cost recovery for assets built to serve new load prior to the load reaching specific milestones. Commissions can also take other measures such as requesting that utilities perform modeling runs with load forecasts that remove speculative load.

The second step is for a utility to determine the timeframe over which it can reasonably meet new load and how it will serve and manage that load. While utilities have an obligation to serve customers within their service territory, they do not have an obligation to do so on a specific timeframe or with a given set of resources. A utility's obligation is to serve load in a way that manages system costs and maintains system reliability. Utilities can use multiple tools to:

- *Manage load temporally through demand flexibility.* While some data center load is relatively flat and has a high load factor (and therefore has minimal potential for temporal management), other new load offers opportunities for energy efficiency and demand flexibility. For customers with temporal flexibility, utilities can offer tariffs and DSM programs that incentivize customers to reduce usage when demand and prices are highest (RMI 2024a).
- *Manage load geographically by incenting utilities to site in certain locations.* Utilities with access to surplus generation or high penetrations of low marginal cost resources (such as wind) can offer tariffs that incentivize companies to locate in their geographic region. Utilities with more

limited access to low marginal cost resources can set tariffs that disincentivize location in their region.

- *Set a timeline for serving new load that minimizes total system costs.* Utilities can assess the timeline for new projected load connection in conjunction with the changing cost of adding new generation resources and grid-enhancing technologies over time. Rather than viewing load as a given in a specific year, utilities can view the timing of load connection as another factor to consider in minimizing system costs. If a new customer wants grid service within 3 years, but a 5-year timeframe may allow the utility to build new generation at a substantially lower cost to the system, that can be factored into planning for the new load.
- *Ensure that resources used to serve new load are part of a least-cost plan.* When utilities are considering whether to retain existing fossil-fuel resources beyond previously planned retirement dates to serve load and maintain reliability, best practice is to include the full forward-going costs of maintaining the fossil fuel plants, as well as the cost to build and maintain new resources. An existing asset that requires substantial investment to sustain it is less likely to be economic than one that requires minimal near-term operations and maintenance (O&M). Analysis of the cost of reliance on existing fossil fuel resources is especially relevant given that many new data center customers have explicit 24 x 7 carbon-free energy goals (WRI 2023).
- *Incentivize customers or third parties* to (1) build dedicated resources owned by or contracted by the customer to manage load and mitigate system impacts and (2) deploy state-of-the-art measures to ensure operations are as efficient as possible. If customers can manage some of their own peak load through efficiency and on-site generation, provide their own backup power, or provide other grid services, utilities may be able to build or acquire fewer generation units and make fewer grid investments and, in return, offer lower tariffs to the new load customers.[18]

The third step, to be conducted in tandem with the second step, is for utilities and new large-load customers to understand how new load impacts total system cost and cost allocation. While these issues have traditionally been addressed in rate cases outside of the IRP process, information about how new load will impact total system costs and cost allocation can be important in helping new customers decide where to locate, when to begin construction, and whether they should self-supply to manage their load. Analysis of how new load impacts system costs overall and individual customer classes specifically will help utilities manage cost increases and cost-shifting resulting from new load.

Finally, states can consider measures to address the pace and type of new loads that locate in their jurisdiction. While some new loads may bring economic benefits such as jobs and tax revenue, others—such as bit-coin mining—are more likely to increase electricity system costs while bringing few jobs.

[18] While these recommendations focus on actions that utilities and commissions can take to manage new load, measures and mandates can also come from the state legislature. These fall outside the scope of this guide.

Best Practice 11. Transparently represent distributed generation and storage

Develop forecasts of distributed generation and storage adoption and incorporate them into the modeling process.

Historically, IRPs have focused demand-side resource analysis on energy efficiency and demand response. Many states set up utility customer programs to encourage adoption of these demand-side measures across market segments and income groups. Even with higher levels of distributed PV and storage adoption that may prompt revisiting the scope of demand-side resources in IRP, the relative lack of focus on PV and storage remains true. For example, Arizona Public Service has one of the highest levels of distributed PV penetration in the country and its demand-side resource analysis remains focused on energy efficiency and demand response (see more on Best Practice 19 through Best Practice 22). However, planners still need to forecast adoption of distributed resources that help meet load needs and potentially defer T&D investments. In general, this analysis appears as part of the load forecast section in IRPs and is treated as a load modifier, so it is netted out of the load forecast. Duke Energy Indiana's 2021 IRP is an example of this approach (DEI 2021).

Customer-sited distributed generation and storage, community solar, and utility-owned distributed resources require different approaches. This stems largely from (1) with how much notice the utility has about deployment and operation of these resources and (2) the compensation mechanisms for these resources that inform adoption and operation. As with end uses, best practice is to forecast or simulate adoption and operation of distributed resources separately.

Planners typically forecast adoption of customer-sited resources through a linear regression that relies on current adoption trends and expected payback. Best practice is to use a propensity of adoption method that captures expected changes in customer preference, regulations, and policies. Portland General Electric and Puget Sound Energy leveraged the National Renewable Energy Laboratory's (NREL) dGen tool (NREL dGen n.d.-a) in their latest IRPs to forecast customer adoption using a propensity of adoption approach (PGE 2023; PSE 2021). In contrast, Duke Energy Indiana implements a linear regression method based on the Itron MetrixND platform (Itron, n.d.; DEI 2021). For community solar adoption forecasts, planners can look to existing support programs, which typically have adoption caps. Utility-sited resources can be retrieved from the utility's distribution system plans (see Best Practice 47).

Operation of resources depends in part on whether they are dispatchable. Operation of customer-owned distributed resources are best modeled at an hourly basis and compared against hourly load profiles for each customer segment in order to estimate net metering or net billing credits when relevant. For example, Duke Energy Indiana uses 20-year irradiance data to simulate rooftop solar production for selected locations within its service territory and produces a typical day hourly generation profile for each month of the year. Customer-owned distributed storage requires elaborate methods to forecast dispatch and determine contributions to the grid. Given its relatively low adoption, no clear best practice exists to model customer-owned distributed storage.

Deployment and operation of customer-owned distributed resources is heavily contingent on its economics, which in turn is influenced by rate structures, compensation schemes, and supporting policies. A current best practice is to make clear assumptions about the regulatory and policy environment, and to develop a sensitivity analysis if a key regulatory or policy condition may change during the planning horizon (see Best Practice 30). An emerging best practice is to consider how distributed resource operation could be influenced if these resources are aggregated under virtual power plants, as Portland General Electric did in its 2023 IRP. Substantial growth of behind-the-meter storage will likely enhance rooftop solar economics amidst changes in net metering regulations, as well as provide resilience and reliability benefits (LBNL 2023d).

The consideration of avoided costs for customer- or utility-owned distributed resources is generally a matter of statute, even though it is technically adequate to recognize the upstream benefits from these resources where the models do not.[19] The analysis can consider avoided costs of transmission, distribution, and environmental and internalize them in the overall system costs. For example, Arizona Public Service's 2023 IRP included a market potential study that produced and internalized avoided costs of energy efficiency measures, which can be extended to other types of distributed resources (APS 2023).

The current practice of treating distributed generation and storage as load modifiers suffers some of the same issues as the traditional treatment of energy efficiency, demand response, and other distributed energy resources (see Best Practice 19 through Best Practice 22). In particular, conflating load and distributed resources for resource adequacy assessments introduces distortions due to the inherent differences in risk and uncertainty profiles. While using net load may be fine for lower penetrations of distributed energy resources, emerging best practice would require separately modeling distributed generation and storage from load in resource adequacy assessments.

[19] Capacity expansion models would typically internalize capacity and energy benefits of distributed energy resources when considered both as a load modifier or competitive resource, since they displace capacity and energy needs from supply-side resources.

SUPPLY-SIDE RESOURCE INPUTS

Best Practice 12. Use accurate assumptions for the costs of new resources

Use accurate cost assumptions for new resources that reflect current market data and include all relevant programs and incentives.

The cost to procure new resources changes constantly. The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals (RFP). This data reveals actual procurement costs at a specific place and time. These costs can be sense-checked against cost estimates in the best-available public resources, such as the NREL's Annual Technology Baseline, U.S. Energy Information Administration's (EIA) Annual Energy Outlook, and EPRI's Generation Technology Options Report, or proprietary data from industry sources such as Black and Veatch, Wood Mackenzie, and others (NREL ATB 2024; U.S. EIA AEO 2023a; EPRI 2024b). In Colorado, utilities such as Public Service of Colorado use both generic cost assumptions and market data. First, they develop their IRP models using generic cost assumptions. Once the model is approved by the commission, they use the model to evaluate bids from a competitive RFP (PSCo 2021). This allows the utility to see what resources the IRP model selects directionally using public industry sources, and then to use actual cost data to select specific projects.

If RFP results are out of line with expectations based on public and industry sources, utilities can conduct supplemental analysis to better understand and explain the source of the deviation. This can be particularly important during times when market disruptions occur, such as the supply chain challenges and inflation resulting from the COVID-19 pandemic. For its current 2025 IRP cycle, Puget Sound Energy hired Black and Veatch to develop cost assumptions for its IRP based on the consultant's experience as a project developer. The utility shared the study through its Resource Planning Advisory Group. As part of the study Black and Veatch will compare the cost assumptions it developed for Puget Sound Energy to those published by NREL in its Annual Technology Baseline and account for any major deviations (PSE n.d.).

Future cost trajectories are best developed based on technology maturity curves, such as those used by NREL and EIA, rather than adopting existing simplifying assumptions. Such assumptions may seem impartial, but they can skew results for or against specific resource types. Best practice is to avoid using simplifying assumptions when not supported or justified by research or analysis. For example, reliance on flat cost trajectories for all resource types when there is uncertainty about how resource costs will change in the future is not a neutral assumption. It results in bias in favor of mature generation resources with minimal additional cost declines expected, such as gas plants, and against newer

> ***The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals.***

resources with larger technological advancement and cost declines expected in the future, such as solar PV, wind, and BESS.

Additionally, new resource cost assumptions will be most accurate and useful if they are developed to incorporate all relevant and up-to-date tax and program incentives as well as any other relevant funding that are likely to affect a resource's cost. Beyond correctly modeling all credits and incentives that are available for new generic and specifically planned resources, utilities can use the availability of credits and incentives to drive project selection and placement. It may be appropriate to model location-specific new resources rather than view all new resources as generic.

The IRA, in particular, changed the cost landscape for wind, solar, biomass, geothermal, battery energy storge, CCS, and hydrogen. Under the IRA, facilities generating energy from these resources are eligible for either a production tax credit based on their generation or an investment tax credit based on their size. Added bonus tax credits are available for solar and wind facilities located in energy communities and that use domestically manufactured materials. Nuclear plants and advanced energy projects can also receive tax credits through the IRA (White House, n.d.). The cost implications of these and other features of the IRA merit consideration when developing IRP inputs, including all potential bonus adders (RMI 2024b) and bonus tax credits available from siting new resources at the site of a retired or retiring fossil plant.

Best Practice 13. Represent the full cost and risk of advanced technologies

Ensure the model reflects and captures the full range of costs and risks associated with advanced technologies.

In the case of new or particularly complex technologies that are not commercially available, there may be no market data on which to rely, and annual studies from NREL or the EIA may have limited cost data. This is especially important as utilities consider advanced decarbonization solutions such as CCS, carbon capture utilization and sequestration (CCUS), advanced and small nuclear reactors, long-duration battery storage, and conversion of natural gas plants to fire or co-fire with hydrogen. While pilot projects may provide useful data points, such projects are by their nature not in the commercial stage. Therefore, planners will want to use cost and performance data cautiously and account for differences between the pilot and the planned or modeled project.

Megaprojects, especially those that rely on new technology, require special attention for cost estimation and sensitivities. History has shown that such projects are prone to dramatic cost overruns and rate impacts for utility customers (Rand 1988). The larger and more complex a project, the greater the likelihood that it will experience extreme cost growth (Rand 2017). Care must be taken to model the potential for greater risk with large projects and uncertainty with new and untested technology. The examples below from Mississippi (Schlissel 2009; Amy 2018) and Georgia (U.S. DOE 2023b) illustrate some potential issues.

Advanced Technology Example: Kemper County Coal Internal Gasification Combined Cycle (IGCC) Megaproject

The Kemper County IGCC project was intended to combine a new coal gasification plant with carbon capture and storage. When Mississippi Power Company sought a Certificate of Public Convenience and Necessity for the project in 2009, it estimated that the first-of-its-kind plant would cost $2.1 billion. There were warning signs at the time that costs were likely to increase. None of the estimates in the company's filing were subject to cost caps, few of the vendors for parts had been selected, and detailed design for the project had not yet begun. The cost to build traditional coal units at the time had already been trending upward for years. One intervenor in the 2009 regulatory docket recommended modeling sensitivities that increased costs 20 to 40 percent. Even these recommendations underestimated how much costs would rise. By 2018, the carbon capture portion of the project had been canceled, and the capital cost of the project had reached $7.5 billion. Customer rates had been 15 percent higher for 2 years, and after years of debate and testimony, utility regulators approved a settlement that required utility investors to absorb about $6.4 billion of the cost. "The economics really didn't work out and the technology was hard to perfect," the Mississippi Power CEO stated after the settlement.

In general, larger expected capital expenses warrant more careful review. Including a worst-case cost scenario informed by data and outcomes from other recent and relevant projects as an IRP sensitivity is good practice. This might take the form of a cost sensitivity that is plus or minus 20 or 50 percent, or even 100 percent, depending on the order of magnitude of cost ranges available from pilot projects, studies, or other uses of the technology. Such a scenario allows utilities and commissions to weigh and understand the costs and risks of the new technology against the likely much narrower bands of uncertainty and risk associated with commercially available alternatives to determine what cost range would make a technology cost-effective and worth the risk.

Advanced Technology Example: Georgia's Vogtle Nuclear Plant Megaproject

In 2009, at the start of site construction, Vogtle nuclear plant's Unit 3 and Unit 4 project in Georgia was expected to cost $13 billion. By June 2022, the project cost had increased to over $32 billion. According to the DOE, almost all of the overrun was attributable to four factors in the cost of construction: the need to redo improperly executed work along the way, supply chain delays, low labor productivity, and worker attrition. These issues are not necessarily unique to building nuclear power plants. Although they may be difficult to predict, greater contingency planning is needed to properly parameterize the cost of a project this size. Regarding nuclear projects specifically, the DOE's "Pathways to Commercial Liftoff" report on nuclear sets a plus-or-minus 20 percent threshold in estimating project costs as an aspirational goal for coming in on budget for future nuclear, indicating high cost uncertainty (U.S. DOE 2023b).

Best Practice 14. Include realistic assumptions about resource availability timing, without unnecessary constraints

Understand limits and constraints on timing and schedule for new resource construction without unnecessarily constraining resource builds.

In addition to developing accurate capital cost assumptions for new generation resources (discussed in Best Practice 12), robust IRP capacity expansion modeling includes factors related to timing of construction. These include the risk of construction delays due to siting and permitting, local opposition, the interconnection queue, and supply chain constraints. Utilities must carefully balance between letting optimization models optimize and imposing constraints to reflect real-world construction and interconnection bottlenecks. The best way to address this tension is to model scenarios with and without supply constraints and vary constraints over time to reflect realistic expectations about factors that will impact future resource availability.

Scenarios without constraints provide valuable information on the economically optimal solution and provide directions to the market on what the utility may be looking to procure. A more constrained scenario informs the utility about alternative options if it cannot overcome near-term supply constraints. Scenarios with static and unchanging constraints (for example, an annual build limit of 300 MW for a specific resource type for the entire study period) may be less useful than scenarios that vary constraints over time to reflect potential changing market conditions.

Supply chain issues following the COVID-19 pandemic, as well as constraints in labor availability (especially for specialized labor), demonstrate the importance of planning for risks and uncertainties related to labor and materials availability and delays. Public Service Company of New Mexico and El Paso Electric, for example, renegotiated multiple supply agreements for solar resources due to COVID-19-related supply chain challenges (PNM 2023). Although issues stemming from the pandemic have gradually improved, they have affected planning across consecutive IRPs. To incorporate delays such as these, planners either run sensitivities that deterministically alter new resource builds to reflect expected conditions or, in the case of supply chain constraints, treat them as annual, maximum build limits. DTE Energy’s 2022 IRP implemented annual build limits for all resources, including renewable energy resources, citing challenges with the items mentioned above as well as recent RFP experience (DTE 2022). While the utility included these constraints throughout the study period, the IRP states that “The Company is expecting to build on these advancements and efficiencies learned through the execution of the first several years of projects, thus, the annual MW limit increased over time” (DTE 2022, 102).

While ongoing interconnection reform efforts aim to address delays in resources coming online, current and potential future interconnection-related delays are still factors to address in IRPs. Utilities can demonstrate to regulators and stakeholders that an adequate amount of new generation planned in the near term will be able to interconnect in time and provide a contingency plan. One approach to interconnection-related uncertainty is to be more proactive with resource procurement (PA Consulting 2023). For example, if IRP modeling shows it is economically optimal to add 500 MW of new solar by 2028, the utility can issue an RFP ahead of need for that amount and timing, as well as additional levels and potentially earlier timelines. Evaluation of bids at levels in excess of the targeted amount is useful for addressing longer-term needs.

At the same time, processes and policies designed to hasten interconnection, such as surplus interconnection and generator replacement,[20] are worth exploring to understand cost and time implications of using existing interconnection rights to bring additional resources online. Using existing interconnections can help achieve economies of scale and accelerate deployment timelines. Utilities are increasingly seeing the benefits of considering existing interconnection rights in resource planning. Xcel Energy, Otter Tail Power Company, and Great River Energy in Minnesota, for example, have all planned or executed projects using existing interconnection rights in their jurisdictions (Xcel Energy 2023; Otter Tail 2021; Great River Energy 2021). All three utilities are transparent about the cost and timing benefits of such projects. Otter Tail sees "the transmission queue for new interconnection of wind as a significant hurdle to introducing new wind resources outside of utilizing surplus interconnection at existing plants (Otter Tail 2021, 65)". Xcel Energy states, "By using existing grid connections, we're able to provide customers with carbon-free energy in the most efficient and cost-effective way" (Xcel Energy 2023). Great River Energy likewise states, "Use of the existing [generator interconnection agreements] is beneficial for our membership as we receive more advantageously priced wind in our portfolio as a valuable hedge while avoiding significant costs, resulting in a net benefit to our members" (Great River Energy 2021, 1).

Best Practice 15. Limit renewable integration cost adders

Study and fully justify all integration cost adders applied to new renewable energy resources.

As the penetration of renewable energy resources on the grid increases, utilities need a way to quantify and represent the grid services needed for balancing, such as transmission upgrades, regulation and reserves, voltage support, and real-time variability. Planners can capture some of these costs in capacity expansion and production cost models. Alternatively, utilities can develop renewable energy integration costs based on external studies and evaluate the impact of increased renewable energy deployment on the need for system-level upgrades and grid services.

Caution is needed when conducting and evaluating these studies. First, the results are highly dependent on the resource plan modeled and are often more reflective of the existing resource mix than the level of new renewable resources added. Santee Cooper's solar integration study modeled as part of its most 2023 IRP illustrates this challenge. The utility assumed that Winyah, a 1,260 MW coal-fired power plant, would not retire until 2031. Since many coal plants cannot ramp up and down quickly, modeling results indicated challenges (cycling, re-dispatch) with integrating a high penetration of solar resources until after 2030. After the plant retirement date and replacement with faster-ramping peaking resources, the cost of renewable energy integration dropped significantly. The utility used these findings to support its decision to delay the retirement of Winyah from 2028 to 2031. However, the study results did not

[20] Surplus interconnection refers to an unused part of an interconnection service. When a generator retires, if the holder of the interconnection service seeks to keep the service and install replacement resources, they can often do so without having to conduct a full interconnection study and wait in the interconnection queue.

support this finding—instead they showed that delaying Winyah's retirement was what was driving high solar integration costs. Santee Cooper did not evaluate integration costs under any earlier retirement scenarios, where Winyah would be replaced by more nimble resources such as gas combustion turbines or BESS.

Another area for caution is that the results are also often portfolio-specific; they are not wholly transferable across portfolios and scenarios that rely on different resource mixes. A utility would need to model integration costs across multiple resource portfolios to more accurately capture the grid impact of new resource additions. Modeling might double-count costs across the integration cost study and the capacity expansion modeling if the utility is not careful, especially where the study is conducted in isolation from the rest of the resource planning process. This can be avoided by syncing up the integration studies with the resource planning modeling and carefully tracking the services and costs that are quantified already in the production cost and capacity expansion modeling. Finally, system costs that would be incurred regardless may be attributed to renewables only. This can be avoided with robust modeling and transparent analysis.

Best Practice 16. Model all avoidable forward-going resource costs

Model all avoidable, forward-going costs for all existing resources, including coal and gas plants.

Appropriately modeling retirement of existing fossil fuel units requires accounting for all costs that are avoidable. That includes avoidable capital costs that would be included in the rate base, fixed O&M costs included in retail rates, and variable operating costs (including fuel and variable O&M expenses). While it is common for utilities to model fuel and other variable costs, utilities sometimes omit certain capital expenditures and fixed O&M from the model and instead address these costs in a post-processing step (or not at all).[21] If the model does not evaluate all avoidable costs, it does not factor them into retirement decisions. Modeling of avoidable costs can be coupled with modeling of unit retirements to fully evaluate the economics of continued reliance on existing resources, as discussed in Best Practice 37.

Generally, utilities develop capital expenditure schedules based on specific projects planned in the near term. Often these schedules only cover the next 3 to 5 years, with projected spending substantially dropping off beyond this period.[22] This approach regularly underestimates likely capital expenditures by ignoring spending more than a few years out, as well as spending associated with unplanned outages, non-routine expenditures, and uncertain future environmental regulations. The lumpiness and unit-specific nature of ongoing capital additions to power plants can be a challenge to represent in IRP modeling, but these costs can be substantial.

Modeling capital expenditures properly, including annual variations and unit-specific detail, is important to resource planning decisions such as whether and when to retire a power plant from service.

[21] For example, Santee Cooper did not enter projections of capital expenses for its coal plants in the EnCompass capacity expansion model. Instead, the utility included capital expenditure differences by portfolio in the final net present value power costs for portfolios that varied from others in terms of coal plant retirement dates (Public Service Commission of South Carolina Docket No. 2023-154-E, Santee Cooper Response to Sierra Club Data Request 1-8).
[22] This is based on some of the authors' experience reviewing projected unit cost data in numerous rate cases.

Additionally, environmental compliance costs are often large enough (in the tens to hundreds of millions of dollars range) to drive a power plant retirement decision. Even though there is uncertainty regarding which aging facility parts may break down, when, or the likelihood of environmental regulations to increase costs, unexpected costs are all but certain. Ignoring costs because of uncertainty in the exact amount or timing results in underestimates of future system costs. For example, in Tri-State's 2023 Electric Resource Plan (ERP) in Colorado, the company's original modeling did not account for future environmental compliance costs, particularly those related to the recent U.S. Environmental Protection Agency (EPA) greenhouse gas rule under Section 111. The settlement agreement in that case, which is currently before the state regulatory commission, would secure improved modeling that accounts for these costs (CO PUC 2023).

It is best practice for a utility to benchmark capital cost projections for a unit against its spending at the plant in recent years to evaluate whether future projections may deviate substantially from recent experience. Another option is to review and incorporate into the utility's analysis current or forward-looking industry average estimates, such as average annual values based on unit type, size, and age developed by engineering firm Sargent and Lundy. The EPA developed a unit-specific "life extension cost" for use in its own capacity expansion modeling that simulates a large, one-time sustaining capital cost investment incurred when units reach a certain age (U.S. EIA 2019; U.S. EPA 2023). If the utility's projections deviate substantially from both its own historical data and industry averages, best practice is to evaluate why and adjust forecasts for modeling—or justify the deviation in the IRP.

Another best practice is to develop a schedule of planned maintenance and capital expenditures based on a unit's retirement date that factors in a typical ramp-down in spending in the years just prior to retirement. Scenario modeling is the best approach, because programming a capacity expansion model to vary capital expenditures schedules based on a unit's retirement date can be tricky.

Best Practice 17. Model battery energy storage options

Model a variety of short- and long-duration battery storage options to capture the differential value each option can provide to the system.

Energy storage is a highly flexible resource with the potential to become ubiquitous in modern power systems as both a capacity resource and a grid resource. Storage is already playing an outsized role in near-term resource deployment (U.S. EIA 2024c). Typical current IRP modeling approaches may oversimplify aspects of the design, operation, and value of storage resources, missing their full value stack (RMI 2015a). Some utilities are demonstrating improved practices. AES Indiana, for example, evaluated the value of BESS as a capacity resource and for providing grid services. As a result, the utility deployed a 20 MW battery to provide primary frequency response, an important ancillary service (AES Indiana 2024). Robust IRPs will evolve to capture the reliability and resilience benefits of BESS, including for resource adequacy and ancillary services.

The value of storage as a flexibility resource is a function of the particular portfolio. The value changes as the portfolio and system needs change. For example, when a utility is short on flexible resources, lithium-ion batteries provide significant value to the system. But once the utility has sufficient sub-hourly reserves, the value drops to the market value—that is, until the utility's system or demand changes again, and its demand for flexible reserves increases.

Overstating the value of various value streams risks adding the wrong kind of storage. While short-duration lithium-ion batteries may be well suited to provide an initial quantity of reserves, long-duration storage such as an iron-air battery may be a more cost-effective and efficient solution for longer-term back-up and reserves. Most utilities model at least one type of short-duration storage[23] in IRPs, most commonly 4-hour BESS. Other short-duration options, such as 2-hour and 8-hour BESS, offer different services and economics that may fit better with specific grid needs. A 2-hour BESS offers narrow peak services but is lower cost than a 4-hour BESS and may be a more economic option for meeting limited periods of need. An 8-hour BESS can provide power for longer periods of time but is more expensive than a 4-hour BESS. It is important to accurately model the costs and capabilities of multiple storage options to determine the duration(s) that are the best fit for the utility's system (EPRI 2023a).

Another value of storage is its ability to enhance power system resilience. Storage can be part of microgrid and fully islanded systems, and it can make the system less dependent on fuel delivery or weather-based performance in times of stress. The IRP framework rarely captures these unique aspects of storage value. At the very least, these benefits can be qualitatively considered in portfolio screening processes.

Looking Ahead: Internalize storage resilience benefits in modeling

An aspirational practice entails internalizing the resilience benefits of storage within IRP capacity expansion models. This would entail enabling capacity expansion models to represent the stochastic elements that underpin resilience valuation, as well as modeling microgrid formation and operation as a resilience strategy.

For long-duration storage, several technologies are in the early stages of development or commercialization. Technologies include mechanical, thermal, electrochemical, and chemical systems that discharge stored energy for at least 8 hours and up to 1,000 hours, depending on the technology. Even though these technologies are in a nascent stage of development, utilities can model them as part of a resource plan and rely on them as replacement resource options further out in the study period (beyond the next 5 years).

Long-duration storage can provide firm, dispatchable, zero-carbon capacity, which is a need many utilities have identified. Our review of 20 IRPs from 2023 and 2024 found that 12 included at least a discussion of long-duration storage technologies, and 8 included them as a resource option.[24] For example, Southwestern Public Service Company in New Mexico modeled several scenarios that relied on long-duration energy storage for its 2023 IRP (Xcel Energy New Mexico 2023).

To consider long-duration storage in IRP, utilities need data on various technologies and need to know how to model them. While long-duration storage is not yet represented in commonly used sources of

[23] Definitions for short- and long-duration storage vary. Some parties also use the term medium-duration storage. In this guide, we refer to short-duration as less than 8 hours and long-duration as 8 hours or longer.
[24] IRPs vary considerably in defining "long-duration," so interpreting this finding requires a fair degree of caution.

information on capital and operating costs of generation and storage resources, such as NREL's Annual Technology Baseline, utilities can use other publicly available data sources. One such source is McKinsey & Company's report, *Net-zero power: Long duration energy storage for a renewable grid* (McKinsey 2021). Utilities can also refer to other industry projections of capital and operating costs and parameters for long-duration storage technologies, issue a Request for Information from technology developers prior to IRP development, or use data from recent RFPs. As with solar, wind, and lithium-ion battery technologies, it is reasonable to assume a downward cost trajectory for BESS technologies associated with technological advancement and learnings, as well as resolution of supply chain challenges in future years.

Best Practice 18. Be consistent in treatment of emerging technologies

Model the costs, availability, and risks of emerging technologies in a consistent and unbiased manner.

Planners can model emerging supply-side technologies in IRPs despite uncertainty related to costs, procurement, and performance. As deployment of BESS, solar, and wind over the past decade has demonstrated, the cost to deploy emerging technologies can change quickly. Emerging technologies are likely to be part of a least-cost portfolio, especially in a decarbonized future. The challenge for planners is to ensure they evaluate emerging technologies consistently and to make informed, transparent decisions about which emerging technologies to include in capacity expansion modeling. Consistent, unbiased evaluation allows utilities to understand the cost and system impacts of particular technologies and clearly communicate to regulators and stakeholders the reasoning for technologies utilities included and omitted from resource plans for a given timeframe.

Examples of emerging supply-side technologies include small modular nuclear reactors, long-duration energy storage, hydrogen, and CCS, to name a few. A best practice is to evaluate emerging technologies for cost, availability, potential, deployment timing, and associated performance risks to both shareholders and utility customers. Portland General Electric's 2023 Clean Energy Plan/IRP (PGE 2023) includes a discussion of all of these technologies, among others, though not all were included in portfolio modeling. Other IRPs, such as the 2024 Xcel Upper Midwest IRP (Xcel Energy 2024), include emerging technologies in the capacity expansion model, though typically for limited sensitivity runs after the date by which they are expected to be commercially available. Evaluation of emerging technologies also may occur outside of IRP, in supplementary studies.

While available information varies by emerging technology, it is important that the IRP clearly discuss how the utility considered each technology and evaluated them fairly. It would be inappropriate for planners to include one resource type while omitting another without clear support, including the timing of its expected availability. For example, modeling for Santee Cooper's and Dominion Energy South Carolina's 2023 IRPs includes small modular reactors as supply-side resources as emerging resource options, but no others (Santee Cooper 2023; Dominion SC 2023). This choice effectively gives small modular reactors a privileged status among technologies that have yet to reach commercial viability and could bias results in favor of the reactors.

As a general rule, utility plans that rely on emerging technologies in the near term (e.g., 5–10 years in the future) draw substantial scrutiny and skepticism. Cleco Louisiana, for example, modeled the Madison coal plant installing CCS technology in 2028 in all scenarios for its 2021 IRP (Cleco 2023). CCS is not currently deployed by any electric utility in the United States.[25] While CCS is likely to be commercially available at some point in the future, it is not realistic to assume that any utility can economically deploy the technology within the next 5 years. Likewise, good planners make it clear what assumptions are required for an emerging technology to be feasible and reasonable. For instance, characterizing how much of a capital cost overrun would eliminate cost-effectiveness of the technology can help illuminate risk and contextualize portfolio results.

In some instances, cost parameters for emerging technologies are too uncertain to estimate. In the context of deep decarbonization scenarios, Duke and other utilities have modeled an emerging resource with all of the performance characteristics and costs of a combustion turbine, but without greenhouse gas emissions or fossil fuel costs. This so-called "clean capacity resource" typically first appears approximately 20 years in the future, in the 2040s, and represents a proxy resource that is expected to be developed by that timeframe. The advantage of this method is that it allows utilities to run scenarios that examine what type of new resource may be needed in a deep decarbonization future and what a least-cost portfolio may look like should such a resource materialize. However, there is inherent risk in modeling scenarios that feature unknown and unproven technologies. The greater the importance of such technologies in the company's preferred portfolio, and the further they are from common commercial practice, the more information stakeholders and regulators will need from the utility to understand the risks.

Demand-side resource inputs

The IRP process began with least-cost planning in the 1980s, developed in part to explicitly account for demand-side resources to meet load (LBNL and ORNL 1989; Hirst and Goldman 1990). Traditionally, utilities have developed a companion study—the market potential study—that quantifies the technical and achievable/economic potential of demand-side resources as a part of the utility's preferred portfolio. The market potential study has historically focused only on demand response and energy efficiency. This section of the report focuses on practices for these resources. (For treatment of other distributed energy resources, see Best Practice 11.)

Using market potential study results, an IRP internalizes the effects of energy efficiency, demand response, and other demand-side resources in one of two ways:

1. *Load modifier approach*. This is the most common method and relies on demand-side resource potential studies performed outside of the IRP process. Using this approach, planners incorporate cost-effective demand-side resources into the IRP as a load reduction. Examples of utilities that used the load modifier approach in recent IRPs include Jacksonville Electric

[25] See the Advanced Technology Example on page 33. Southern Company attempted to construct an IGCC unit with a CCS plant at Kemper. This resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion) before the Mississippi Public Service Commission ultimately pulled the plug on the project and ordered Mississippi Power Company to continue to operate the plant on natural gas.

Authority, Avista, and Dominion Energy South Carolina (Black and Veatch 2023; Avista 2023; Dominion SC 2023).

2. *Competitive resource approach*. This approach incorporates demand-side resources in the capacity expansion model as priced, competitive resources that can be selected endogenously as part of the capacity expansion optimal decisions. The Northwest Power and Conservation Council (Northwest Council) uses this approach for its regional power plans under the federal *Northwest Power Act,* as do utilities such as PacifiCorp, Portland General Electric, and Xcel Energy (Northwest Council 2022; PacifiCorp 2023; PGE 2023; Xcel Energy 2024).

Rather than prescribe one approach, the following sections provide best practices for implementing each of the methods, depending on the approach regulators or utilities select.

Best Practice 19. Ensure thoughtful and consistent assumptions for demand-side resources

Ensure assumptions driving demand-side resource characterization potential are thoughtful and consistent with other assumptions in the IRP.

Both the load modifier approach and competitive resource approach need to reflect actual program implementation and evaluation practices closely, including: (1) realistic program design and implementation practices, (2) appropriate levels of measure adoption rates (reflecting various non-economic factors), (3) measure and program costs, and (4) policy and regulatory requirements.

While market potential studies themselves are outside the scope of this guide, best practices entail including in these studies emerging demand-side technologies and practices, potential cost reductions for demand-side resources in the future, non-energy benefits (e.g., improvements in comfort, indoor air quality, productivity), up-to-date avoided costs, and maximum achievable adoption rates based on best practices by leading jurisdictions.

IRP modelers can run a variety of scenarios to capture a full range of demand-side resource estimates based on the potential study. For example, Ameren Missouri conducted a comprehensive DSM market potential study in April 2023 to inform its 2023 IRP. The study employed a methodology to account for interactions among DSM measures, load flexibility analysis, and scenario analysis. The utility benchmarked results of the study against comparable utility programs to ensure consistency with industry expectations (Ameren Missouri 2023a).

Both the load modifier approach and competitive resource approach are susceptible to bias with respect to measure adoption rates. If IRP modelers or market potential study analysts use overly conservative rates for measure adoption or measure adoption growth, savings results will be lower than can be supported by studies.[26] Customer paybacks for demand-side investments, non-energy impacts, and customer knowledge and awareness of technologies and programs (supported by the utility's customer outreach and marketing) may substantially influence customer decisions to implement DSM measures. Market potential study developers and IRP modelers would ensure results from the study are realistically

[26] For example, see TVA's 2015 IRP, which uses low adoption rate assumptions (Synapse 2015), pp. 10 to 15.

implementable by internalizing customer adoption rates that reflect customer economics and assumed program interventions (e.g., rebates, financing, customer outreach).

Best practice includes developing and using varying adoption rates for demand-side resources, including the maximum achievable adoption scenario based on aggressive historical savings achievements by leading jurisdictions and favorable policy and program scenarios (e.g., paying for 100 percent of the measure cost–comparable to treatment of supply-side resource costs, comprehensive customer outreach, and marketing and financing programs). A case in point is the NWPCC's approach to estimating total achievable potential for the regional power plan. NWPCC assumes that total cumulative market penetration rates increase to 65 percent, then 85 percent of the total technical potential over a 20-year timeframe (LBNL 2021e). Best practice for the competitive resource approach is for IRP modelers to produce a capacity expansion model run that offers savings up to those consistent with the measure adoption rates in the maximum achievable scenario in the most recent market potential study. Best practice for the load modifier approach is to include a maximum achievable scenario in the market potential study, as DTE did in its 2019 study by using "high" and "low" adoption scenarios (DTE 2019).

Policy considerations also need attention. For example, if certain energy efficiency investments for low-income households are required, the IRP model needs to select these investments regardless of the cost and consider them as a fixed input. In addition, some jurisdictions have minimum savings or budget targets for other market segments (e.g., small commercial customers) that are set by policy or regulation. While these targets could create suboptimal resource selection results, IRP modelers can strive to model these mandates as accurately as possible in at least one IRP scenario. States such as Washington require all cost-effective conservation to be procured (subject to a rate cap), regardless of the market segment. Utilities can model some of these requirements with a load modifier approach or simply by requiring the model to select these resources, while treating remaining conservation and demand response measures through a competitive resource approach.

Best Practice 20. Model and bundle demand-side resources carefully

If utilizing the competitive resource approach, model and bundle demand-side resources carefully to closely reflect actual program implementation and evaluation practices.

Under the competitive resource approach, demand-side resources are grouped together in a manageable number of bundles as inputs to the capacity expansion model. IRP modelers can develop these bundles to reflect how energy efficiency and demand response programs are typically designed, implemented, and evaluated for cost-effectiveness. Some programs (e.g., home retrofit) contain multiple measures from low cost (e.g., lighting) to high cost (e.g., HVAC) in order to meet customer needs and avoid "cream skimming" that targets only the most cost-effective measures and abandons others often offered with them as a package. IRP modelers also need to model specific market segments carefully so that the modeling approach closely resembles actual program implementation practices.

Carefully bundling energy efficiency and demand response measures[27] avoids unnecessary computational complexity within a capacity expansion model. Modeling energy efficiency and demand response at the measure level and allowing the model to select individual measures based on costs, for example, may prevent the model from solving. Current practices for measure bundling include aggregation by cost (e.g., NWPCC, PacifiCorp) and load shape (e.g., Indiana Michigan Power). For example, Indiana Michigan Power divides the bundled energy efficiency measures in 5-year increments and annual 1,000 MWh units to reduce modeling time (IMP 2022).

When creating bundles for demand-side resources, planners can ensure that the temporal sequence of expenditures is realistic and relatively smooth, without large changes over time. Without such guardrails, the model may select considerably different amounts of demand-side resources each year. This may fail to capture realistic patterns of consistent program offerings or follow actual program design and administrative practices for stable or gradually increasing program efforts and funding.

Another best practice is to allow the model to select bundles less frequently than annually. Modelers also can ensure that costs for continued programs and new programs are different. Given first-year start-up costs, existing programs should produce a smoother output and are more likely to be selected in subsequent years. This is easily achieved by bundling measures based on whether they are new or existing and assigning bundle costs accordingly.

An example of this approach is Duke Energy Indiana's 2022 IRP. Duke Energy Indiana modeled a study period from 2021 to 2050. It represented its DSM savings with increased granularity in the near term and consistent with its DSM planning cycles: 2021–2023 and 2024–2026. The IRP grouped subsequent savings in 8-year periods from 2027–2034, 2035–2042, and 2043–2050. During the period 2021–2023, the model was required to select the bundle that corresponded with the utility's currently approved demand-side management portfolio as well as low-income program savings. The model could then choose an "expanded measure" bundle, an "expanded measure + higher avoided cost" bundle, or no bundle. The expanded measure scenario included current and newly proposed measures, as well as new energy efficiency programs where measures included in the study did not logically fit into an existing offering. A bundle with higher avoided costs further enhanced savings by increasing participation, increasing measures offered, or doing both. While Duke Energy Indiana did not model all potential scenarios developed through the market potential study, the utility chose which scenarios to model through collaboration with its Demand-Side Management Oversight Board. The utility aimed to implement several best practices, including offering bundles of savings in excess of those achieved under existing programs and constructing near-term bundles in a way that mimics their procurement through a 3-year DSM cycle.

Some state requirements call for cost-effectiveness of energy efficiency programs to be determined at the program or portfolio level (NESP DSP n.d.). Modelers can produce program-level bundles that reflect a few key programs that are complemented by measure-level bundles. However, demand-side resource choices made by the capacity expansion model do not translate directly to optimal program design; rather, those choices should inform the amount, market segment, location, and type of demand-side

[27] Bundling should be done separately for demand response and energy efficiency and measures. Demand response measures are oriented to capacity savings, while energy efficiency is mostly oriented towards energy savings (although it provides capacity contributions as well).

resource to procure. This is consistent with supply-side model outcomes that select generic resources but leave the specifics to CPCN, siting and permitting, and procurement processes.

Best Practice 21. Ensure consistency with IRP scenarios

Ensure consistency between demand-side resource assumptions and IRP scenarios.

A key IRP principle is to represent the potential of energy efficiency, demand response, and other demand-side resources in a way that is consistent with the scenarios modeled in IRP. That is because assumptions made for IRP scenarios, such as those related to electrification and other load growth, also affect the potential for peak load reduction, load-shifting, and energy savings. This consistency is particularly important in the load modifier approach to DSM modeling because potential studies are typically developed before and in isolation from IRP modeling exercises. The competitive resource approach can produce more internally consistent portfolio choices, although consistency in basic cost and technology assumptions to characterize load and demand-side resource is important.

Aligning key assumptions (especially avoided costs and underlying load forecasts) in the demand-side resources potential study with assumptions in the IRP can mitigate distortions in modeling energy efficiency and demand response in IRP. A utility can conduct the potential study at the same time as, or right before, the IRP process and ensure consistency of key assumptions. Stakeholders need sufficient time and resources to participate in both the potential study and IRP processes, if they are conducted separately. If timing of the potential study does not allow for seamless coordination with the IRP, the potential studies can include sensitivities on avoided cost and load forecast assumptions. The utility, with stakeholder engagement, can select results from the sensitivity or scenario analyses that fit best with IRP modeling assumptions or outputs.

Looking Ahead: Co-developed scenarios for IRPs and market potential studies

Ideally, a set of scenarios would be developed ahead of both the IRP and the market potential study to be used in both; however, this is an aspirational practice with implementation challenges.

Best Practice 22. Incorporate all relevant benefits for demand-side resources

If using the competitive resource approach, incorporate all relevant benefits for demand-side resources by following policy objectives and requirements for assessing their cost-effectiveness.

To fairly value demand-side resources, IRP modelers need to incorporate all utility system benefits as well as non-utility benefits that are consistent with all applicable policy objectives. Modeling demand-side resources dynamically in a capacity expansion model is not sufficient because the model typically captures only the benefits of avoiding energy and generation capacity and, when modeled, transmission capacity. However, demand-side resources provide other utility system benefits such as avoided transmission capacity (when not explicitly modeled), avoided distribution capacity, and risk management/hedging, as well as societal benefits such as avoided greenhouse gas emissions and other pollutants.

When a jurisdiction requires consideration of customer and societal benefits (e.g., reducing water usage and greenhouse gases, improving air quality) in cost-effectiveness screening tests to evaluate the benefits of demand-side programs, IRP modelers need to incorporate such non-utility benefits when screening cost-effective demand-side resources (LBNL 2021e). This is one of the principles of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which recommends inclusion of all benefits and costs to achieve policy objectives (NESP 2020a). For example, in its regional power plan modeling the NWPCC incorporates avoided T&D costs in the form of credits that reduce the cost of energy efficiency measures. The NWPCC also incorporates non-utility benefits (e.g., water and O&M cost savings) when modeling energy efficiency in its capacity expansion model (LBNL 2021e). Incorporation of non-utility benefits is consistent with traditional qualitative discussions of supply-side portfolios that have environmental, financial, and other benefits.

Competitive resource approaches can leverage some avoided costs that are endogenously modeled in the IRP process, such as transmission costs or emissions costs. The load modifier approach typically cannot internalize these costs directly in the IRP, instead using externally produced avoided cost studies. Planners can verify consistency between assumptions used to develop avoided cost studies and those used in the current IRP and adjust avoided costs accordingly.

Market Inputs

Utilities commonly rely on market purchases to meet a portion of their energy and capacity needs. Utilities that model themselves as an island–that is, model their utility footprint as if it is not connected to external markets or energy sources–are not accurately reflecting their position in the larger electricity grid and are omitting market resources from consideration. Market resources, both energy and capacity, can frequently lower utility portfolio costs and impact resource selection. Reliance on market purchases, however, requires that utilities study regional resource adequacy conditions to ensure the market can be relied upon to supply energy and capacity needs (PSE 2021; LBNL 2019b). This regional awareness can inform design of scenarios for capacity expansion modeling.

Best Practice 23. Use reasonable market interaction assumptions

Model reasonable levels of market purchases that capture the benefits from market integration without exposing the utility system to risky levels of market exposure.

Aligning capacity expansion modeling with regional resource availability is particularly important because factors such as load growth, growth of variable energy resources, and coal plant retirements affect available capacity. Utilities can provide transparency into treatment of market purchases in their modeling by describing their market studies and justifying the level of market purchases determined to be available for selection by the capacity expansion model.

Modeling a utility footprint as an island simplifies the modeling exercise, but it does not accurately capture potential lower resource costs, including market revenue potential. This tends to disadvantage zero marginal-cost resources such as solar and wind, which the utility can sell in the market. This approach can also disadvantage energy storage, which can store power from the market during hours of low cost for use when costs of supply-side resources are high. These values and revenues streams impact the economics of resource build decisions. Accurate representation of external markets allows the model to see the benefits from market interaction and impacts the model's resource selection decisions.

On the flip side, high reliance on the market requires proper justification. Detailed regional and market risk studies are best practice, but they are also resource-intensive. If the utility is unable to perform a full study or chooses to rely on simplified approaches to market interactions instead of a full study, it can align modeling assumptions with available transmission studies, recent market performance, and other external studies and projections of resource availability in the region.

Puget Sound Energy's 2021 IRP illustrates the importance of assessing regional energy and capacity availability (PSE 2021). The utility historically assumed that 1,500 MW of firm transmission capacity from the Mid-Columbia market hub would provide the utility with the equivalent to 1,500 MW generation capacity available to meet demand. In the past, Puget Sound Energy relied on this assumption to procure less generation capacity and lower its system costs. By 2021, however, three regional organizations had published studies indicating that the Pacific Northwest would transition from a capacity surplus into a shortfall at some point in the following decade without additional resource buildout.[28] In response, the utility decided to conduct a market risk and resource adequacy assessment for the 2021 IRP.

By aligning its resource adequacy model with regional reliability models, Puget Sound Energy was able to "translate the regional load curtailments forecasted […] into PSE-level impacts"(PSE 2021). Results showed that in some simulations, the availability of market purchases could be limited by 500 MW by January 2027. By that date, the utility might only be able to fill 1,000 MW of the available 1,500 MW of transmission (PSE 2021, chap. 7). The market risk assessment further analyzed recent market supply and demand fundamentals. Results showed that trading volume in the day-ahead market had declined 70 percent since 2015, while price volatility had increased. Increases in market volatility were particularly evident when high temperature events aligned with fossil fuel supply constraints at key power units (PSE 2021, chap. 7). This assessment resulted in Puget Sound Energy's decision to limit the number of market purchases going forward and transition short-term market purchases from a 1,500 MW limit to 500 MW. To fulfill its resource adequacy needs, the utility designed its preferred portfolio to reflect additional firm capacity contracts (PSE 2021).

FUEL AND COMMODITY INPUTS

Widespread extreme weather events have shown that fossil-fuel-based units whose fuel supply is not properly winterized are subject to outages during winter weather events. In Winter Storm Uri, for

[28] These included NWPCC, Pacific Northwest Utilities Conference Committee, and Bonneville Power Administration. See (PSE 2015) Appendix G.

example, as much as 6.7 GW of thermal generation capacity was unavailable due to “fuel limitations”(UT Austin 2021).

Resource adequacy assessments performed as part of the IRP process typically do not capture the weather dependence of fuel availability. Even more concerning, the assessment rarely captures such common mode failures, when an underlying event causes a series of correlated outages across certain technologies.

Best Practice 24. Model fuel supply limitations

Incorporate fuel supply limitations, weather-sensitive failures rates, and weatherization investments in resource planning.

Two related best practices improve IRP characterization of fuel availability for fossil fuel resources during extreme events, in line with utilities' continued focus on the impact of weather on the performance of solar, wind, and storage. First, as discussed in Best Practice 4, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Second, in conducting IRP processes, utilities can plan for and model investments in winterizing fuel supply to reduce the common-mode failure rate for fossil fuel resources. These investments require careful analysis to ensure that further investment in the plant for winterization is economically optimal based on the forward-going economics of the plant relative to alternatives. A review of recent resource plans shows a focus on the impact of weather on the performance of solar, wind, and storage without enough focus on the weather impacts on other resource types, including coal and gas plants (LBNL 2023a).

The impacts of fuel supply limitations are another key factor for utilities to carefully consider in resource build or buy decisions. For example, Georgia Power Company recently filed an IRP update requesting approval to build three peaking combustion turbines (GPC 2023). The utility does not have a firm source of natural gas for the proposed plants and plans to operate them on oil during times when gas is not available. Oil is significantly more expensive than gas and has higher pollution levels across multiple emission types. Reliance on oil at the plant means the project will have higher costs and environmental impacts than a combustion turbine unit operated just on gas. Further, if the company faces natural gas constraints in the future, beyond what it assumes in the model, its reliance on oil will increase and so will the associated cost and environmental impacts.

Best Practice 25. Evaluate the impacts of gas price volatility and coal supply constraints

Incorporate fuel price volatility and fuel supply constraints into resource planning, and consider resource-portfolio solutions to limit risk.

Fuel price volatility is a fact of the market and not something that individual utilities can control. High natural gas prices are straightforward to model, but volatility is much more challenging to capture through deterministic modeling. To incorporate fuel price volatility in electricity system modeling, utilities can use stochastic risk analyses that use Monte Carlo simulation to evaluate portfolio performance under different commodity price scenarios.

Utilities can take measures to manage and mitigate price volatility through various fuel procurement strategies—for example, through hedging programs that lock in a portion of supply at known costs to avoid the risk of high costs in the future. But hedging can be costly and, ultimately, a utility has more control over its resource supply mix than its fuel supply. By diversifying its resource mix and reducing the portion of its system that relies on the volatile input, a utility can control its fuel price volatility risk. Specifically, utilities can manage the portion of generation that comes from natural gas in each resource portfolio and design and model scenarios that limit the portion of a utility's portfolio subject to price volatility. This means focusing energy resource procurement on energy resources such as solar and wind that do not require fossil fuel inputs.

Price volatility and uncertainty has historically been most common in the gas market, but it has also been present in coal markets in recent years due to several factors. First, challenges stemming from labor strikes at both mines and the railroad transportation network resulted in price spikes in some parts of the country, particularly the Midwest and Appalachian region (Energy Ventures Analysis 2022; U.S. EIA 2023b). Some coal plants had to reduce operations due to low coal supply. There is likely to be more price uncertainty and possibly increasing prices in the future as more coal plants close, demand for coal drops, smaller coal suppliers go out of business, and the coal supply chain continues to contract. With more market power, the remaining large coal producers will have more control over coal supply, likely driving up the cost of coal in the future. Stochastic analysis and modeling of various coal price forecasts can help capture this risk. In addition, utilities can limit their exposure to these risks by reducing operations at, and planning for retirement of, coal plants.

Transmission inputs

The IRP process provides crucial inputs for regional transmission planning. In May 2024, FERC issued a Final Rule (Order 1920) that provides guidance for transmission planners on transmission planning and cost allocation issues (FERC 2024). The order requires regional transmission planners to identify transmission needs driven by changes in power supply and demand by developing long-term scenarios at least 20 years long—a timescale that matches the typical IRP planning horizon. Likewise, FERC noted the need for proactive planning for resources not yet in development, so that planners can prioritize the most cost-effective solutions.

Best Practice 26. Consider transmission alternatives and infrastructure expansion

Consider transmission alternatives and expansion of regional transmission infrastructure as part of the resource planning process.

To prioritize transmission solutions, transmission planners look to IRPs for long-term forecasts of supply-side resources that are most likely to materialize. In turn, utilities can incorporate information from these long-range transmission plans into IRP scenarios and allow endogenous transmission builds in capacity expansion models (where modeling capabilities allow). This best practice informs regional transmission planning and helps co-optimize transmission expansion and generation portfolio development. This is already occurring to some extent, and new modeling capabilities may support further effort in the future.

The primary driver for regional transmission expansion is the changing mix of generation resources that utilities are selecting. Regional transmission planning organizations including NorthernGrid and WestConnect build their regional transmission plans in a bottom-up manner using individual utility inputs (Gridworks 2023). In California, the reference IRP prepared by CPUC staff directly provides inputs for CAISO's Transmission Planning Process (CPUC 2023). Some large utilities such as PacifiCorp consider regional-scale transmission within the IRP. It's common even for smaller utilities to consider intra-system transmission upgrades in the IRP. However, these are typically in the form of hardcoded, preplanned transmission projects, rather than allowing the model to select transmission to help meet resource needs. The absence of wider exploration of transmission expansion and transmission optimization in IRPs are barriers to regional transmission buildout (Gridworks 2023).

A critical improvement is enabling capacity expansion models to select transmission buildout via tranches of transmission available at different costs. Modelers can also run scenarios that enlarge intrastate or regional connections to see how such changes shape optimized utility resource portfolios and costs. Doing so creates two benefits: (1) the utility is better prepared for a future with greater regional transmission planning and buildout, and (2) the utility can generate information that helps shape regional planning by informing regional planners about how different transmission options fit into a least-cost portfolio.

Some utilities already explicitly perform resource planning in a way intended to inform transmission planning. As PacifiCorp's 2023 IRP notes, "IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers." The IRP included several large, preplanned, hardcoded transmission projects and endogenous selection of transmission to inform the relationship between "probable near-term projects and their transmission dependencies." Endogenous transmission capabilities specifically included "new incremental transmission options tied to resource selections, existing transmission rights tied to the use of post-retirement brownfield sites, incorporation of costs associated with these transmission options, and transmission options that interact with multiple or complex elements of the IRP transmission topology"(PacifiCorp 2023). As another example, Public Service Company of Colorado incorporated a section in its Clean Energy Plan that analyzed the necessary transmission investments to support its Preferred Plan, acknowledging the substantial transmission grid support investments required to interconnect a large portfolio of increasingly spread-out generation resources and accommodate generation retirements (PSCo 2021).

Best Practice 27. Properly justify bulk power system interconnection costs and constraints

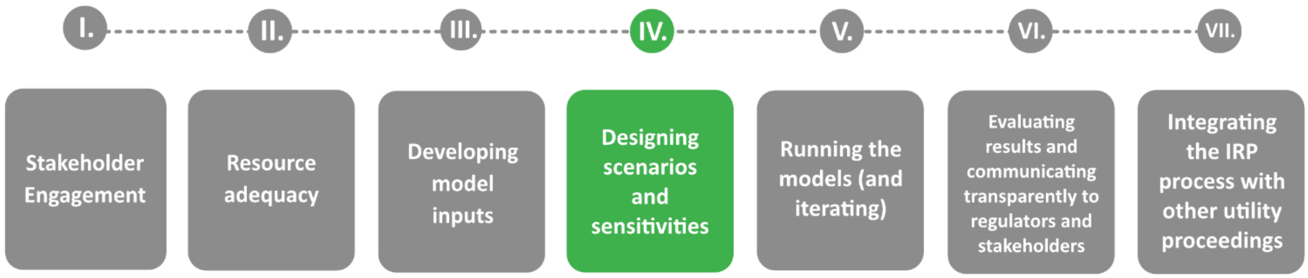
Properly justify interconnection costs and constraints modeled for new generation resources at the bulk power system level.

Ideally, transmission planning is integrated with generation planning. Transmission resources can be made available to the IRP model to select endogenously in the same manner as supply- and demand-side resources. For reasons discussed above, it is not always feasible or possible to fully integrate transmission planning into capacity expansion modeling based on model limitations, computing limitations, and a lack of full information on transmission expansion options. As an alternative, utilities sometimes estimate incremental transmission interconnection costs and attribute them to specific generation projects in the capacity expansion model. Even where interconnection capacity is constrained, utilities can model interconnection costs representative of the cost of addressing the constraints rather than omitting generation resources.

Given recent sharp growth in the total cost of interconnection-related network upgrades and the cost of such upgrades relative to generation project costs, it is best practice for utilities to factor interconnection costs into a project's capital costs. According to one report (Grid Strategies 2021) interconnection costs for new renewable resources were less than 10 percent of total generation project costs until a few years ago. Recently interconnection costs have risen to between 50 percent and 100 percent of total generation project costs as penetration of renewable energy resources on the grid increases.

Although reform is underway at both national and regional scales to change how costs are allocated, interconnection charges are still generally borne by the energy project developer. Utilities can ensure that the interconnection costs they model in IRPs are properly justified based on robust studies. Interconnection costs beyond the near term can reflect improvements in the interconnection process that are already underway. Additionally, interconnection costs can be applied fairly across all resource types to avoid bias in resource selection. Proper modeling and representation of interconnection costs will remain an important issue as additional transmission upgrades are increasingly needed to accommodate interconnection of resources on the bulk power system.

IV. Designing scenarios and sensitivities



Definitions

A **scenario** is a model run with a specific set of input assumptions and constraints—internal and external—to provide insights on distinct questions. Often, scenarios represent different goals or views of the future. Scenario A, for example, may include a high gas price forecast and low renewable energy capital costs, whereas Scenario B may include a low gas price forecast and high renewable energy capital costs. In this example, both scenarios serve as bookends at opposite ends of two scales. This is a common method for structuring scenarios.

A **sensitivity** is a model run that changes a single key input to understand how that input affects or drives results, often across multiple scenarios. The objective of a sensitivity analysis is to understand how results are affected by a single variable. For example, a higher load forecast may be applied to Scenarios A and B to test the effect of that one change layered across the range of other variables represented by each scenario.

A **portfolio** is the resulting resource mix from each scenario or sensitivity analysis, or a particular set of resources programed into a scenario to test. An optimized portfolio represents the least-cost solution to a capacity expansion model for a given scenario, considering risk and uncertainty.

Scenarios are the foundation of resource plan development and the framework for the model's optimization runs. Because utilities cannot evaluate every potential system outcome, they use scenarios to focus on inputs that are most likely to vary in the future and organize them around views of the likely future, specific policy goals, or other priorities. Modelers feed inputs and constraints for each scenario in the optimization engine (capacity expansion model) to produce a distinct optimized resource portfolio for each scenario. They then feed the resulting resource mixes into the production cost model to produce the optimized operational and dispatch plans for each scenario. The goal is for the utility to model a representative number of scenarios that provide sufficient information to inform the development of a preferred portfolio.

Sensitivity analysis enables a utility to understand how a change in a single input or constraint impacts its optimal resource mix. There are two general types of sensitivities: (1) a sensitivity that tests how the optimal resource mix changes assuming the utility plans for a change in one assumption from the start and (2) a sensitivity that performs a “robustness check” on a specific portfolio to quantify the operational and cost risks of an inaccurate single assumption. Both types of sensitivities are important, and both can help inform a utility resource plan.

For example, if the utility wants to understand how a higher gas price forecast will impact its resource mix, it re-runs the capacity expansion model using a high gas price forecast. The results will tell the utility how to plan its system if it thinks that gas prices are likely to rise (or even just become increasingly volatile). Alternatively, if the utility is interested in understanding the risks or robustness of each portfolio to high gas prices, modelers can run all of the portfolios through a new production cost modeling run with a high gas price forecast. The results will reveal how system operations and costs will change for each scenario if the system is built assuming base gas prices, but then gas prices are much higher.

Planners face several challenges to designing effective IRP scenarios and sensitivities, including the following:

1. *Modeling a full, comprehensive range of uncertainties vs. producing straightforward, informative results.* Too many scenarios, with too much complexity, risk confusing stakeholders. But too few scenarios risk omitting evaluation of critical factors.
2. *Balancing stakeholder requests with utility priorities and commission requirements.* Utilities can reduce the number of scenarios they have to run by designing scenarios that satisfy the priorities of multiple parties where interests overlap.
3. *Minimizing shareholder risks vs. minimizing ratepayer costs. The interests of utility shareholders and ratepayers do not always align.* That can drive utilities to model specific scenarios and omit others that could be lower cost or lower risk. For example, a utility may not model early retirement of an aging fossil fuel generator with a large undepreciated balance because that creates shareholder risk.

All these challenges require common sense, an open mind, and prudent judgment. This chapter offers best practices for exercising these qualities when building scenarios, evaluating scenarios, and using scenario results.

Best Practice 28. Model a base case that allows for easy comparison

Model a base case scenario that facilitates comparison across scenarios and sensitivities and ensure internal consistency across all scenarios and sensitivities.

Utilities include multiple scenarios in their IRPs to test a range of future outcomes. To ensure a useful comparison across all of these scenarios, a best practice is to first develop a base scenario as the starting point for all other scenarios. Modelers can use this base scenario to ensure they design all subsequent scenarios and sensitivities to be internally consistent so that results can be readily compared across scenario and sensitivities. Any subsequent scenarios can be designed to deviate from the base in a clear and methodical manner—i.e., with different loads, commodity prices, regulatory assumptions, new resource cost assumptions, and more.

Best practice is to design the base scenario to reflect a realistic view of the world—i.e., an "expected" scenario—and abide by all existing federal, state, and regulatory requirements. Where there is regulatory uncertainty about the future of a final regulation, utilities can model a range of scenarios both with and without the regulation (as discussed in Best Practice 30).

Where a utility is modeling both its own footprint and the larger market the utility operates in, it is also important that assumptions be applied consistently across geographic scales (except where deviations are intentional). For example, it is critical to align input assumptions, such as commodity and market prices, regulatory assumptions, and resource cost inputs, across geographic scales.

Consistency across scenarios is also important. A high decarbonization scenario, for example, is likely to result in lower market energy prices in many hours of the year due to the higher prevalence of zero-marginal-cost resources, but also higher prices in some hours. If the utility does not develop its own scenario-specific market prices, it can select a third-party market price forecast that reflects the utility's assumptions about the relationship between decarbonization in its footprint relative to decarbonization in the rest of the market. A lower energy market price may reflect the assumption that decarbonization is happening across all regions, while a base or high market price may reflect the assumption that decarbonization is happening more rapidly in the utility’s footprint than in the broader market region.

It is also important for utilities to use the results of sensitivities and scenarios thoughtfully in drawing conclusions. Revenue requirement results can be most easily compared across portfolios developed using the same fundamental price forecasts for commodities (e.g., gas, coal), electricity market prices, emissions, loads, new resource costs, regulatory context, and other consistent inputs. Comparing costs across portfolios developed with different fundamental inputs can be used to understand risk and uncertainty, but not to draw direct conclusions about which portfolio is least-cost.

Best Practice 29. Design scenarios to evaluate uncertainty and risk

Design a range of scenarios that provide information about uncertainty and risk across a range of futures.

The objective of scenario development is to understand uncertainty and risk in the electricity system and determine how to best manage them through resource planning. Scenarios focus on evaluating and understanding likely future views of the world (and the electricity system), the impact of specific policy goals on resource planning, how market trends could impact resource options, and how risk and uncertainty around various inputs and variables impact the optimal resource mix. Some scenarios may focus on isolating the impact of a few specific variables. Others help the utility understand what type of full system changes are necessary to meet a specific goal. Ideally, all of the scenarios modeled meet existing state and regulatory requirements and represent reasonable stakeholder priorities.

Table 1 identifies common uncertainties and risks that IRP scenarios address, with examples. Best practice is to focus on developing scenarios that evaluate real and likely variables and futures. Scenarios that evaluate extreme themes or views of the world may be interesting, but ultimately are not likely to provide useful information for resource planning purposes.

Table 1. Common uncertainties and risks that IRP scenarios address, with examples

Uncertainties and Risks	Examples
High electrification	Dominion Energy South Carolina 2023 – high electrification scenario (Dominion SC 2023)
High DER and DSM future	Dominion Energy South Carolina 2023 – high DSM scenario (Dominion SC 2023)
Technology advancement (CCS, hydrogen, small modular reactors)	Tucson Electric Power 2023 – P09 Portfolio with Small Modular Reactors (TEP 2023a)
Long-duration storage	Public Service Company of New Mexico 2023 – long-duration storage scenario (PNM 2023)
Decarbonization by a certain year	Xcel Energy Upper Midwest 2024 – 100 percent carbon-free by 2050, Avista 2023 – Clean Portfolio by 2045 (Xcel Energy 2024; Avista 2023)
No new fossil resources after a certain year	Avista 2023 – no new natural gas, Santee Cooper 2023 – no new fossil generation (Avista 2023; Santee Cooper 2023)
Retirement of all fossil fuel plants by a certain date	PacifiCorp 2023 – retire all coal plants by year-end 2029, retire all natural gas plants by year-end 2039 (PacifiCorp 2023)
Compliance with proposed environmental regulations (e.g., Clean Air Act section 111(d) rule for greenhouse gas emissions)	Xcel Upper Midwest 2024 – environmental policy scenario (Xcel Energy 2024)
Increased environmental regulation	Dominion Energy South Carolina 2023 – aggressive regulation scenario (Dominion SC 2023)
Extreme weather	PacifiCorp 2023 – extreme weather load forecast sensitivity (PacifiCorp 2023)
Change in reliability requirement or reserve margin	Public Service Company of New Mexico 2023, Avista 2023, Xcel Energy Upper Midwest 2024 (PNM 2023; Avista 2023; Xcel Energy 2024)
Increased industrial and data center loads	Xcel Energy Upper Midwest 2024 – data center load sensitivity (Xcel Energy 2024)
Increased transmission buildout	PacifiCorp 2023 – All Gateway scenario (PacifiCorp 2023)
Stakeholder-requested scenarios	Public Service Company of New Mexico 2023, Avista 2023, PacifiCorp 2023, DTE Electric Company 2022, Duke Energy Indiana 2021 (PNM 2023; Avista 2023; PacifiCorp 2023; DTE 2022; DEI 2021)
Commission-mandated scenarios	Public Service Company of New Mexico 2023 – impacts of a range of carbon prices (PNM 2023)

Sometimes it makes sense to combine multiple uncertainties and risks in a single portfolio to test a scenario with a complete view of the future. Other times it makes sense to isolate and test particular changes in sensitivities. Transparency is key, for scenarios and sensitivities as well as the utility's preferred portfolio.

Best Practice 30. Plan for and incorporate important regulatory factors

Model all final, proposed, and likely regulations to allow time for proactive planning and identification of no-regrets actions.

Regulatory uncertainty is a particularly impactful uncertainty for planners to account for in scenario analysis. This can take the form of final rules that are being legally challenged, formally proposed rules, or even regulations that are likely but not yet proposed.

For example, NREL's annual Standard Scenarios report accounts for regulatory uncertainty in its U.S. electricity sector outlook by modeling all scenarios under current policies, as well as under two national electricity sector carbon dioxide emissions constraints: one that reaches 95 percent net decarbonization by 2050 and another that reaches 100 percent net decarbonization by 2035 (NREL 2023). Reference scenarios that only include current policies may serve as a point of comparison for other scenarios and provide insight on the risk of the status quo, but do not represent the expected future.

For final regulations that are new or subject to legal challenge, some utilities choose to model compliance as a single alternative scenario rather than as part of a base scenario. Modeling compliance as just a single sensitivity or alternate scenario and not in the base case limits the utility's ability to plan for a future with the regulation in place and identify no-regrets actions that are economic regardless of the regulation's status.

Proposed policies and regulations provide valuable insight into the direction of regulatory momentum and can give utilities the opportunity to figure out how to model new and complex requirements. When it comes to environmental regulations in particular, failing to model any further regulation prior to a finalized rule nearly guarantees that capacity expansion modeling misrepresents the future by underestimating environmental compliance costs. Future regulations are inherently uncertain, but modeling current or pending regulations is a better central case than assuming no future regulation. For example, EV deployment targets aimed at decarbonizing transportation will very likely grow as low-cost EVs become more readily available and charging infrastructure becomes more prevalent. Environmental regulations of emissions related to air and water will almost certainly continue to increase in stringency and call for lower levels over time, even if there is temporary backsliding. Modeling scenarios and sensitivities that examine the impacts of regulatory factors such as these provides insights into how the utility's strategy would need to respond to changes to rules and makes resource plans more responsive to potential

Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.

changes. Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.

It is common for utilities to reject modeling regulations that are not yet finalized, with the justification that prior to finalization, uncertainty surrounding the rule is too great for incorporation into planning. Utilities also may avoid modeling final rules that are being formally challenged in legal venues. For instance, Avista's 2023 IRP acknowledges the impact of draft rules that EPA issued in May 2023 relating to coal- and natural-gas-fired resources, but states that no adjustments will be made to the resource plan prior to issuance of final rules (Avista 2023). Duke Energy's 2023 IRP for North and South Carolina devotes a chapter to "Planning for a Changing Energy Landscape," noting the rapid advancement of policy-driven financial incentives, such as clean-energy-related tax credits under the *Infrastructure Investment and Jobs Act* and IRA, as well as new environmental regulations such as EPA's proposed *Clean Air Act* Section 111 rule for greenhouse gas emissions. Duke evaluated the performance of its Core Portfolios and Supplemental Portfolios under conditions of the proposed 111 rule for "informational purposes" (Duke Energy Carolinas 2023, chap. 2). Although Duke's modeling shows that the proposed rule may have important planning ramifications, the utility did not include the proposed rule in its base planning assumptions because it is "still being interpreted, clarified, and commented on and may change prior to being finalized" (Duke Energy Carolinas 2023, chap. 3). Similarly, Dominion Energy in Virginia and Santee Cooper in South Carolina did not consider the proposed rules in their recent IRPs (Dominion VA 2023; Santee Cooper 2023).

EPA's proposed Greenhouse Gas Regulations under Section 111 of the *Clean Air Act* is an example of how a proposed environmental rule can provide an advanced look at the direction of a final rule. The proposed rule included a variety of compliance measures including the option to comply through CCS, hydrogen conversion, co-firing with natural gas, or lowering capacity factors. Although the final rule, published in 2024, altered some specific aspects of the rule and removed the hydrogen conversion compliance option, the basic structure of the regulation, its stringency, and ramifications for highly-polluting power units—namely, reductions in carbon dioxide emissions—were largely unchanged. Studying the impact of the proposed rule would have provided an advanced look at the risk of continued reliance on regulated units, particularly those that pollute the most.

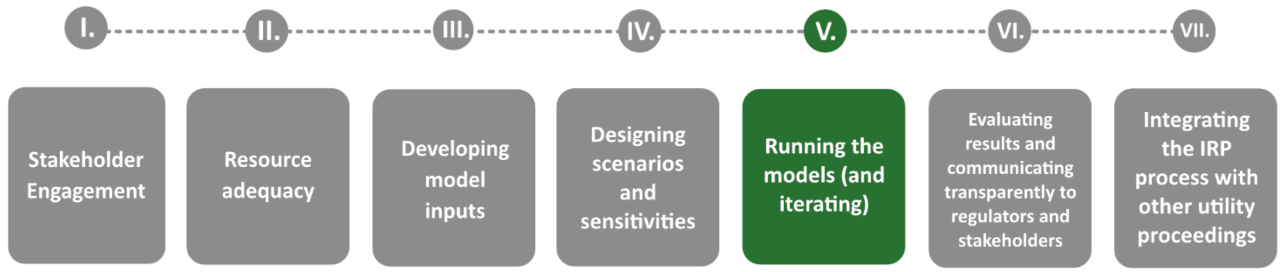
Modeling the impact of proposed regulations can also inform intelligent regulatory design. When EPA publishes new environmental rules, the agency solicits feedback from industry. Incorporating proposed environmental regulations into IRPs can provide quantitative evidence to support industry feedback.

For example, Duke's modeling of the proposed 111 rule shows that although the Core Scenarios are "generally in line" with the first phase of the proposed 111 rule, compliance paths through later phases produce dramatically different results from the Core Scenario, with striking cost impacts. One tested path would require an additional 1.6 GW of offshore wind and an additional gas combustion turbine by 2035, both of which exceed Duke's forecast for resource availability and add $3.9 billion to the sensitivity's present value of revenue requirements (PVRR). Another path relies on hydrogen blending and increases the PVRR through 2050 by $11.4 billion. While these changes indicate that EPA's proposed 111 rule has the potential to change the least-cost system for Duke, the utility did not factor the sensitivities into its preferred resource plan.[29] This creates a risk that the utility's plan will be rendered suboptimal by EPA's final 111 rule.

Best IRP practice is to take a reasonable and considered view of expected future regulations and include them in the base case scenario. Where there is significant uncertainty, planners can analyze alternative futures with more and less strict regulations in other scenarios or sensitivity analyses, or both. Assuming environmental regulations that are not finalized will not exist in the future can lead to costly resource decisions and delays in resource planning and resource procurement decisions.

[29] Duke notes a variety of near-term (2023–2026) actions to study hydrogen availability; but it otherwise does not incorporate the proposed 111 rule into its planning, aside from stating that it will update its planning assumptions as new requirements evolve (Duke Energy Carolinas 2023, chap. 4).

V. Running the models (and iterating)



This section of the report presents nine best practices relating to selecting, initializing, calibrating, and running the various models used in the IRP process.

Best Practice 31. Thoughtfully select capacity expansion and production cost models

Thoughtfully select capacity expansion and production cost models and use modeling software that can perform both functions if possible.

Capacity expansion and production cost models offer two complementary perspectives on the costs of the power system. While the industry trend has been attempting to integrate these models, software still tends to be specialized. A best practice is to verify the outcomes of a capacity expansion model using a more accurate and detailed production cost model in an iterative process.

Historically, some utilities relied on models that only have production cost capabilities. Instead of letting the model develop an optimized portfolio, utilities manually develop and test specific scenarios. This approach is inefficient, imprecise, and unlikely to lead to a least-cost outcome. Another best practice is selecting modeling software that can perform both capacity expansion and production cost functions.

A small number of commercially available models are typically used by utilities for capacity expansion and production cost optimization in IRPs, such as EnCompass, Aurora, and Plexos (Yes Energy, n.d. EnCompass; Energy Exemplar, n.d.-a Aurora; n.d.-b Plexos). That is in part because few models have adequate capabilities; have been used widely enough for utilities, regulators, and stakeholders to trust the results;[30] and offer sophisticated and consistent customer service to address the myriad of issues that using these models entail (including access to prepared and curated datasets). Expanding the pool of available models could help lower barriers to accessing modeling capabilities. National laboratories have developed several well vetted open-source models such as ReEDS (NREL ReEDS n.d.-d) and RPM (NREL RPM n.d.-e) capacity expansion models and the Sienna production cost model (NREL Sienna n.d.-f), among others (MIT and Princeton GenX n.d.; PyPSA, n.d.; RAEL SWITCH n.d.). These open-source

[30] This creates a barrier to entry for new models. A model must be trusted in order to be widely used, and it must be commonly enough used to be trusted.

models have limitations in their user base, support, and user interface that would need to be addressed before being fully viable alternatives.

Capacity expansion and production cost models developed and maintained by third parties such as commercial vendors and government agencies are important because they are accessible at least in theory by any stakeholder. That means results can be replicated and models remain relatively unbiased in their design. Open access to datasets also is critical for result replication. In practice, stakeholder access to models can be challenging due to the cost of model licensing,[31] the technical sophistication required for users, concerns about data confidentiality, and some utilities' ambivalence about collaborating with stakeholders at this level (see Section I on stakeholder engagement for more information).

Looking Ahead: Benchmark models to support IRP best practices

To support adoption of best practices in resource planning, utilities would benefit from third-party benchmarking of models—comparing them in terms of performance and outcomes.*

Different models emphasize certain characteristics of the power system over others. For example, they differ in the temporal resolution used to capture operational and investment timeframes. Some models use a time slice approach that emphasizes energy and ancillary service needs; other models use a sample hour approach that emphasizes capacity needs. Ideally, a third party would compare existing models to inform choices to represent the utility-specific power system analyzed in the IRP.

Model assessments would ideally go beyond comparing model attributes to help resource planners choose and implement a suite of models. Challenges with this approach include the proprietary nature of datasets and the time required to set up and run models. A common standard for data inputs could allow for a manageable yet informative number of redundant simulations to verify key decisions.

While model performance is important, other considerations for model selection include transparency, usability, and vendor support (see DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report in MPSC Case No. U-20471)(DTE 2020).

* *The Energy Modeling Forum compares energy and climate models, but to our knowledge, no one has systematically compared and validated models used for utility IRP* (Stanford University).

Best Practice 32. Thoughtfully select a geographic model scale

Thoughtfully select a geographic model scale that allows meaningful analysis of the resource potential and diversity available to the utility system being planned.

There is an inevitable tradeoff between model complexity and performance. This tradeoff is especially relevant to IRP modeling, which can include hundreds of runs to simulate a wide range of scenarios and sensitivities. The more complex the model, the longer the run time. That will limit how many model runs planners can complete within a given timeframe.

[31] In some states, regulators have required utilities to purchase model licenses for intervenors, as in Arizona and Iowa.

Two key aspects characterize model complexity: spatial scales and temporal scales. The spatial scale relates to the level of topological and geographical detail used to represent the power system under study. The temporal scale relates to the time-sensitive granularity of the system's operation as well as the time horizon for investment decisions. Thoughtful choices for spatial and temporal scales—with consideration for their interactions—balance accuracy and tractability (see Best Practice 33 and Best Practice 34).

Key spatial decisions include the choice between zonal and nodal modeling,[32] modeling of integration with regional markets, modeling of transmission connections and limits, and modeling of the utility footprint within the larger region and any relevant ISO/RTO to capture regional impacts on reliability and resource mix (for example, how much can the utility rely on the market).

While nodal modeling is most accurate, zonal is much less computationally- and data-intensive and likely sufficient from a resource planning perspective. Regional market integration can be reflected through a one- or two-step process. For the one-step option, the utility uses full capacity expansion and production cost modeling for the utility's footprint as part of the larger ISO/RTO or region it sits within. For the more common two-step option, the utility first runs the capacity expansion model for the full region to produce market prices, with relaxed constraints for resource builds and unit dispatch.[33] Then, in a second step, the utility uses market prices as an input to model the utility footprint with more granular settings and constraints for both capacity expansion and production cost runs (see Best Practice 40). While full regional modeling is more accurate, it is unlikely to be computationally viable for production cost modeling. At the same time, modeling the utility as an island without regional connections is not a reasonable IRP practice.

Regional modeling requires a scale that reflects geographic diversity in renewable resources and load characteristics. Modeling choices for supply- and demand-side resources are influenced by how their temporal profiles interact and by their location. A best practice is to study historical load and variable renewable energy generation patterns and then establish a minimum set of zones that are explicitly reflected in the model to capture diversity in these patterns. Reliability and resource constraints and parameters are critical model inputs.

Generally, transmission planning is integrated with resource planning processes, but through different modeling exercises. To simulate major transmission connections and limits in a zonal model, planners can create distinct zones for each region. An appropriate spatial scale will reasonably represent transmission corridors—in particular, lines that are typically congested—so the model can more accurately consider transmission lines for expansion (see Best Practice 26III.Best Practice 26). Planners usually choose higher voltage lines (i.e., above 220 kV) and several key substations to capture system topology. In addition, planners will want to consider including nodes that have historically presented patterns in locational marginal prices that reflect congestion, regardless of the nodes' voltage levels.

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[32] Nodal modeling refers to using actual transmission substations and the transmission grid topology to locate load within the model. Zonal models aggregate substations and associated transmission lines and connected load into contiguous zones that simplify the model.

[33] Market price forecasts are dependent upon specific assumptions for gas prices, regulations, policies, and resource deployment within the ISO/RTO footprint.

Best Practice 33. Thoughtfully define the appropriate study period

Use a study period that is long enough to allow meaningful comparison between capital-intensive resources and others that might be considered and built in the future.

The temporal scale for IRPs works at two levels: investment and operation. Capacity expansion and production cost models interact across these scales to ensure rigorously tested least-cost outcomes. With respect to investment temporal scales—the IRP planning horizon—the minimum planning period may be defined by statute or regulation. As a general best practice, the study period extends far enough into the future to include important differences between scenarios with respect to recovery of investment costs and avoid distortions, as discussed below.

Any optimization that is done for a finite modeling period (e.g., 5 years or 20 years) has the potential to be influenced by “end effects,” meaning significant costs that would be incurred beyond the study period. This issue has been recognized since the late 1970s. Proposed solutions include adding a salvage value to any asset and liability or approximating the system’s continued operation (UC Berkeley 1979; Murphy and Soyster 1986). In many instances this is not a significant problem, particularly if the study period is long and the investment scenarios do not have large capital investments whose cost recovery would occur beyond the end year. On the other hand, in cases where there are large investments made near the end of the modeling period, considering and accounting for “end effects” can be quite important.

Typically, planners compare scenarios based on their PVRR (or cumulative discounted costs) over the study period. For example, if a capital-intensive project is brought online near the end of the planning period in one resource scenario but not in another, then the cost comparison between the scenarios may not reflect the real cost differences between the cases. Planners might address this issue by extending the study period a few more years or by making an “end effects” adjustment to the scenario costs.

In addition to issues regarding the overall length of the study period and accounting for potential costs that would be incurred beyond the study period, some optimization modeling assumes “perfect foresight.” The model optimizes the entire study period as each if year’s capacity expansion and retirement decisions can be made with knowledge of future loads, fuel costs, capacity additions, etc. For a particular year, the model assumes future regulatory costs, which can be used to inform near-term decisions. This can be desirable in some instances, but if there is a high level of uncertainty around decisions far into the future, it may be less desirable to have uncertain information drive near-term decisions. In addition, because some optimization models consider more information in making decisions, a long optimization period can also result in long model runtime. Conversely, single-year or multi-year foresight/optimization reduces the model run time, can help space out new builds, and can exclude uncertain drivers from near-term consideration.

The choice of optimization horizon can be especially important for resources expected to have declining costs over time, as with the significant annual capital cost reductions for some renewable and storage resources. In such cases, the optimization algorithm of a least-cost model might delay as much as possible capital-intensive decisions in ways that would not reflect appropriate decision-making. Most models today solve the problem by annualizing investments, applying useful lifetimes, and internalizing these annuities in the objective function. This practice, coupled with using an extended modeling horizon, should prevent end-effect distortions.

Best Practice 34. Thoughtfully select the appropriate time granularity for production cost modeling

Use a time granularity for the production costing simulation that enables modeling of important timing considerations in dispatch.

In addition to the time horizon over which the model makes investment decisions, the resolution or granularity of the dispatch for operation costs is also a critical modeling parameter decision. A best practice for operational temporal scales for both production cost modeling and capacity expansion modeling is using hourly representation, consistent with resource adequacy assessments. Hourly scales enable single-day or even multiple-day chronological representation for system operation that captures some ancillary services needs, such as ramping requirements. Intra-hour analysis that includes primary and secondary frequency, voltage regulation, and other non-economic simulations may be conducted as well in suitable power flow, dynamic, and reliability models.

Full 8,760-hour representations for annual system operation are generally tractable. However, in cases where the spatial scale needs to be highly granular, the complexity of the simulation may increase substantially. In these cases, modelers can use a subset of hours that reflect peak and non-peak hours and seasonality of loads and resources. Ideally, modelers will choose this subset of hours carefully and, when possible, capture consecutive 24-hour periods and even longer timeframes for modeling long-duration storage. While less common in capacity expansion models, many utilities use 8,760-hour representations in production cost models and similar portfolio refinement steps, as demonstrated in several 2023 IRPs (Santee Cooper 2023; PacifiCorp 2023; Avista 2023).

Best Practice 35. Calibrate the production cost and capacity expansion models

Calibrate the production cost and capacity expansion models to anchor them to current system conditions and validate the legitimacy and accuracy of the model results.

Capacity expansion modeling is an inherently theoretical exercise that studies possible evolutions of a power system based on initial conditions and forecasts of key variables. Nevertheless, the model still needs to be anchored in, and calibrated to, current system conditions. The calibration process may be time-intensive and iterative, but it is necessary for the legitimacy and accuracy of models and results.

A best practice is to ensure that the dispatch, dynamics, and prices/costs from the production cost model match those seen in the current power system. For utility-scale modeling, this may include ensuring capacity factors for each simulated unit and technology class are consistent with recent dispatch outcomes, and that the production cost model reflects reasonably well overall system costs.

For larger regional modeling, metrics for calibration may include matching total generation by resource type and zone to capture both technology-level production and spatial distribution. In some cases, matching by individual unit may be possible and necessary to appropriately reflect transmission flows. In any case, planners will need to carefully analyze the import and export profiles in the production cost model output, particularly if the dispatch in neighboring areas is also being simulated, rather than as serving as an input to the model. Puget Sound Energy's 2021 IRP provides an example of such simulation (PSE 2021). Import and export profiles would ideally approximate the seasonal and daily patterns so that the model adequately reflects the surpluses and deficits of power within the planning entity footprint.

In this calibration process, the utility would evaluate its model inputs, make adjustments, and iterate until the model delivers results that more closely match reality. Planners might want to use some level of discretion to avoid overfitting the models, since this may introduce distortions into the production cost model or capacity expansion model that could affect results. For example, trying to closely match winter dispatch conditions for certain resources may induce large distortions in assumed summer operation for the same resources. In addition, actual utility decisions may be driven by factors that the model does not consider, such as risk aversion, sunk costs, or political environment—and hence planners will want to account for these when analyzing model fit against operational data.

Best Practice 36. Let optimization models optimize

Let optimization models optimize resource additions and retirements as a complement to modeling specific retirement scenarios.

The concept of optimization—a process aimed at developing the "best" path that balances tradeoffs, costs, and benefits—sits at the core of IRP modeling. Capacity expansion models are founded on the principle that optimizing for least cost should drive resource builds and retirements. A best practice is to limit unnecessary constraints on the model and allow the model to do what it was designed to do: optimize. The results from optimization model runs provide important information on the best way to balance system costs, needs, and constraints.

Planners can program many aspects of capacity expansion and production cost modeling into the model, including:

1. *System constraints.* These include reserve margins, emission programs, transmission capacity limits, regional import and export limits, reserve and ancillary service requirements, and any other parameters that cover the entire utility system.
2. *Load and demand.* System load and system peak demand.
3. *Resource input assumptions*. These include resource costs, operational characteristics (ramp rates, heat rates), capacity accreditation, shapes (for variable energy resources), outage rates and schedules, and other resource inputs.
4. *Commodity costs.* Examples include fuel costs and carbon prices.

These parameters require programing into the model because capacity expansion and production cost models are not designed to endogenously make decisions about most system constraints and resource inputs. The modeler is responsible for selecting reference values for each input and varying them manually through different scenarios and sensitivities as necessary. Some of these inputs can and should be determined by exercises outside of the core resource planning modeling—for example, the reserve margin and resource capacity accreditation.

There are also key decisions where it is best *not* to hardcode and constrain across resource planning exercises. These are decisions that a capacity expansion model makes endogenously by design, mainly:

1. Resource build decisions
2. Resource retirement decisions

There are legitimate reasons why a utility also may design certain scenarios with specific resource build and retirement decisions programed in, instead of relying solely on an optimized scenario. Such considerations include computational limits, regulatory deadlines, policy requirements, settlement agreements, just energy transition, and many others. Additionally, the remaining life of a resource radically changes plant investment, which can be challenging to accurately and dynamically capture in the model.

Putting aside near-term decisions that are already locked in, a starting point and default best practice is to optimize resource retirement decisions, rather than hardcode them based on utility preference or a decision the utility already made. For example, this frees the model to reveal whether a different retirement date, in the context of all other model parameters, assumptions, and resource alternatives, yields a more desirable solution. The practice of overly constraining IRP modeling through hardcoding retirement dates is very common in utility IRPs. This is driven in part by the outage and capital upgrade cycles for existing fossil plants, such as coal plants. To accommodate these cycles, some utilities, such as Duke Energy Carolinas, conduct separate retirement analyses to develop coal unit retirement dates that they then hardcode into the capacity expansion models. While the external studies provided useful information, the utility did not integrate these retirement analyses with modeling the rest of the electricity system, preventing the model from finding a truly optimal solution.

Likewise, when it comes to new resource builds, capacity expansion models work best when free to choose from among all currently available resource types (and even some emerging ones over the longer term) and free to build what is needed to meet load (subject to system constraints and regulations) in each year. That includes both supply- and demand-side resources, as well as transmission expansion options. Capacity expansion models by design evaluate continued operations versus retirement and replacement with alternatives, but the models can only do this if they are unconstrained in doing so.

Again, there may be value in testing portfolios that lock in retirement or resource build decisions or place reasonable limits on those decisions. Still, best practice is to conduct unconstrained optimization runs for retirement or resource build decisions and include an optimized modeling run with the utility's preferred portfolio. Locking in resource addition and retirement decisions for scenarios and sensitivities may be appropriate after robust modeling is performed to provide clear reasoning and support resource decisions with evidence.

Other modeling constraints may be useful—when testing high and low ranges of uncertain values, evaluating specific unit retirement dates, and seeking to limit the problem size and computing requirements. Supply chain interruptions or interconnection queue constraints, for example, may warrant setting a maximum annual build cap on a given resource type. In such cases, best practice is to be transparent about setting the cap, limit the timeframe for applying it, and provide a well-reasoned explanation. Best practice is to also run scenarios without any caps to determine whether there is a better solution if deployment barriers can be overcome. Further, it is essential for the utility to recognize that such a cap is a modeling construct, and that the market and other on-the-ground realities represent the actual limits to procurement.

A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.

While a utility's preferred portfolio may deviate from the optimized portfolio, it is essential for the utility and regulator to understand the economically optimal results, especially in planning near-term procurement activities. For example, if an optimized scenario shows it is most economic to add 3 GW of solar PV in 2028 to replace a retiring resource, this finding can be used for developing RFPs and communicating to the market that the utility is going to be looking to procure as much solar as it can economically get by 2028, even if there are legitimate reasons for the preferred portfolio as modeled to stagger that resource addition over multiple years.

Limits to optimization models are important to keep in mind in implementing best practices for model optimization. Any model reflects a simplified version of reality. An optimization model, for example, will show planners the lowest-cost resource plan based on selected inputs. It will not tell them which alternative plan could be even lower cost if the planner used different modeling assumptions or inputs. Best practice includes testing a wide enough range of reasonable scenarios that build off optimized results to capture a comprehensive range of possible future conditions. A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.

Best Practice 37. Base power plant retirement decisions on forward-looking costs

Base power plant retirement decisions on forward-looking costs, not sunk costs or cost recovery concerns.

Almost all utility assets have undepreciated plant balances. This is particularly true of legacy fossil fuel generators such as coal plants, which have both an existing plant balance from past investment and ongoing and future capital expenditures to maintain operations and comply with environmental regulations. Existing plant balances are sunk costs that are unavoidable with retirement.[34] Sunk costs do not provide relevant information for resource planning decisions. On the other hand, O&M and fuel costs, as well as ongoing capital expenditures which become part of a plant's undepreciated balance once they are incurred, *are* avoidable with retirement (as discussed in Best Practice 16). In IRP modeling, planners must differentiate between sunk costs and avoidable future costs to accurately assess resource

[34] A variety of regulatory mechanisms, including accelerated depreciation, can help address sunk costs for plants the utility plans to retire.

retirement decisions. Avoidable future costs can only be considered by an IRP model in selecting a retirement date if they are included in the model.

There are three pieces to retirement analysis: *whether* a plant should be retired, *when* it should be retired—including the optimal retirement date, and *how* any remaining balance should be treated in rates after retirement. The IRP process, through capacity expansion modeling, addresses the first piece and part of the second piece.

The determination of *whether* to retire a unit is based on a unit's expected forward-going economic performance and all expected forward-going costs, including sustaining capital expenditures, environmental capital expenditures, and fixed O&M. Best practice is for a utility to ramp down investment in a plant in the years leading up to retirement and include those assumptions in capacity expansion modeling. Ideally, when a unit is expected to become uneconomic on a forward-going basis, planners prioritize it for retirement to avoid incurring additional costs and operational losses that would be passed on to utility customers. Again, sunk costs are *not* considered in the IRP process.

Capacity expansion modeling can identify a unit's economically optimal retirement date. But the decision of *when* to retire a unit also needs to consider the timeline for procuring replacement resources, as well as *how* the utility will handle sunk costs. These decisions typically occur outside IRP processes. Specifically, procurement, cost recovery, and cost allocation decisions are typically addressed in other proceedings. Aligning resource planning modeling with resource planning decisions made outside of the IRP process is important and is discussed in Section VII in this report.

Best Practice 38. Use modeling parameters that capture the value of battery energy storage

Use modeling chronology and parameters that capture the full value that BESS can provide to the grid and accurately capture charging and discharging cycles.

Appropriate capacity expansion modeling capabilities and methodologies are critical for simulating high-renewable electric grids, particularly those that include battery storage of varying durations. The model chronology used in the long-term capacity expansion component is particularly important. Capacity optimization models have long relied on a simulation chronology that optimizes resource builds based on a subset of representative days. That might be some number of days distributed across the entire year, one on-/off-peak day per month, or a typical week per month. Such sampling methods fail to capture the variability in variable renewable energy generation, and storage charging and discharging, across longer time scales. Thus, these methods fail to accurately value the flexibility that long-duration storage resources can provide. To capture the ability of these resources to shift energy across days, weeks, and seasons, it is essential to optimize resource builds using a modeled chronology of 8,760 hours.

Sampled modeling chronologies often fail to capture multi-day lulls in renewable energy generation as they occur both within and across years. They therefore do not consider the implications of such events on resource builds, grid reliability, and energy prices. The magnitude of these lulls will only increase as electric supply shifts toward even greater penetrations of renewable resources. It is critical that utility resource planning include scenarios that capture these lulls as well as other periods of grid stress.

Similarly, best practice in modeling long-duration storage resources requires modeling storage build and dispatch over multiple weather-years and including weather-years with extreme conditions that lead to periods of grid stress. Industry-standard modeling often builds an optimized resource mix designed to meet the annual peak load, with an established reserve margin, under typical weather conditions. However, weather varies from year to year, and that variance can have substantial impacts on energy system requirements. A resource portfolio built around average weather conditions might not meet system resource adequacy standards in a weather-year that includes one or more grid stress periods. Modeling a single weather-year also tends to underestimate the flexibility benefits of long-duration storage resources. Best practice modeling optimizes resource builds over multiple weather-years to produce a resource portfolio that is more robust against weather variability, though we are unaware of any utility that has incorporated this practice into its capacity expansion modeling.

Storage resources are characterized by power discharge capacity as well as energy storage capacity. Most IRP models simplify the representation of storage by prescribing its duration, either with a single value (e.g., 4-hour storage) or modeling storage resources in cohorts of discrete, fixed durations. For example, Portland General Electric's 2023 Clean Energy Plan/IRP modeled six lithium-ion battery durations, ranging from 2 to 24 hours, as well as a 10-hour pumped-storage hydro resource (PGE 2023). This approach simplifies the optimization process and might be the best that utilities can do with commercially available capacity expansion models. But it can miss identifying system needs that could be met with specific durations of storage located at specific points in the system. Best practice would treat power discharge capacity and energy storage capacity as two independent variables, such that the optimal solution ultimately defines the designs for the storage resources needed.

Further, IRP best practice would simulate fully dispatching storage resources with explicit representation of charging and discharging cycles. The 2023 PacifiCorp Clean Energy Plan/IRP describes endogenously modeling dispatched storage resources according to their roundtrip efficiency and other operational constraints (PacifiCorp 2023). The 2023 Tucson Electric Power IRP includes an example of the hourly battery dispatch in its production cost model (TEP 2023a). Accurate modeling of real-world operational conditions for these units requires comparison of sample charge-discharge cycles to empirical profiles. A related practice involves appropriate modeling of different types of long-duration storage—multi-day, multi-week, and seasonal storage units. For more details on best practices for modeling long-duration storage in IRP, see Best Practice 17.

Best Practice 39. Use stochastic approaches for robust portfolio creation

Use stochastic modeling approaches to produce portfolios that are robust to changes in inputs.

A key challenge in IRP is assessing the risk that stems from the array of uncertain inputs to the exercise. Load location and growth, weather, fuel prices, variable renewable energy production, asset outages, capital cost reductions, policies, and regulations are all uncertain. Two key risks that arise from these uncertainties and need assessment are (1) whether the preferred portfolio remains a least-cost option within reasonable variation of inputs, and (2) whether the resulting system is resource-adequate when exposed to varying load, weather, and resource availability. As reported in Section II in this report, properly developed resource adequacy assessments use stochastic modeling to represent the likelihood of shortfalls in the bulk power system and address the second point. This best practice expands on the first point.

Conventional capacity expansion modeling in IRP is a deterministic analysis. Planners input deterministic forecasts for uncertain variables exogenously, and the model optimizes based on these pre-set values. As discussed in Section IV of this report, running scenarios and sensitivities is the traditional approach to managing uncertainty in least-cost or economic decision-making. These mechanisms are easy to understand, but their interpretation is qualitative, and there is no reassurance that the portfolio decisions stemming from these qualitative assessments are optimal (see Best Practice 41).

Capacity expansion models have the capability to run with stochastic inputs, providing tools to test the impacts of uncertainty, although uptake from planners has been slow. Examples of utilities that use stochastic inputs include AES Indiana's 2019 IRP. The utility employed a stochastic capacity expansion model that reflected fuel price volatility and correlation to produce multiple portfolios (AES Indiana 2019). A more common alternative is to use a stochastic approach to test the distribution of costs of preferred portfolios by running a production cost model of the portfolio with stochastic inputs. In contrast to running the capacity expansion model with stochastic inputs, this approach uses stochastic variable costs to recalculate production costs for deterministically defined portfolios. In CenterPoint Indiana's 2023 IRP, for example, the utility performed a stochastic risk assessment to compare portfolios. The stochastic inputs used in these risk assessments included natural gas prices, coal prices, carbon prices, peak loads, and capital costs for renewable energy resources (CenterPoint Energy 2023). TVA, PacifiCorp, AES Indiana, Puget Sound Energy, Idaho Power, and DTE also have recently used this approach. Entities such as PacifiCorp, the NWPCC, and TVA with a substantial amount of hydropower resources in their analyses have traditionally used stochastic representation of hydrological variability in production cost modeling, as well as developing related sensitivities in capacity expansion modeling (PacifiCorp 2023; Northwest Council 2022; TVA 2019).

These best practices produce multiple portfolios based on stochastic inputs or assess the short-run economic performance of portfolios when input variables are stochastic.

Looking Ahead: Use optimization algorithms in stochastic economic modeling

An aspirational practice in stochastic economic modeling would employ advanced robust optimization or chance-constrained optimization algorithms to ensure the distribution of outcomes falls within prescribed ranges given probabilistically defined inputs. These advanced algorithms produce a single preferred portfolio that is designed to be robust to changes in inputs. Inevitably, any best or aspirational practice to perform stochastic analysis in IRPs will substantially increase computational needs, runtime, and complexity.

Stochastic approaches to capacity expansion and production cost modeling do not entirely replace scenario-based analysis and sensitivities. Stochastic approaches are useful when the input variables can be modeled through rigorous probability distributions. However, several inputs to IRPs cannot be modeled like this, such as the likelihood of adoption of certain policies or predetermined retirement of certain assets, among others. Load growth, weather-driven parameters, fuel prices, capital costs, and similar quantitative variables are suitable for stochastic representation. Behavioral aspects that drive load and flexibility profiles are an emergent area of research for stochastic representation.

Best Practice 40. Use the models iteratively

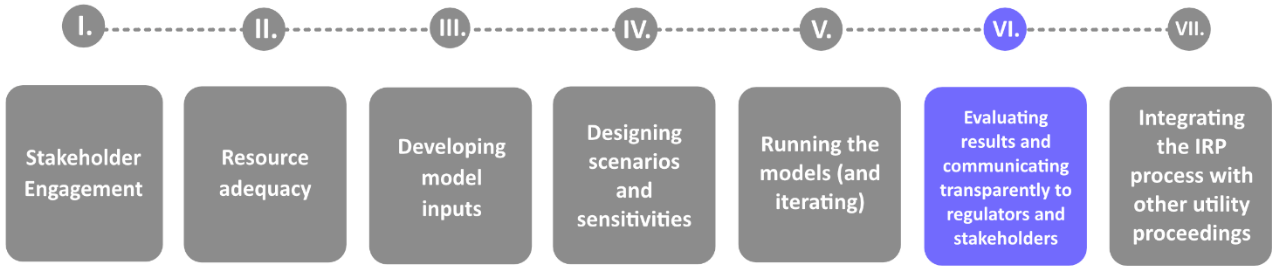
Use capacity expansion and production cost models iteratively to help refine results.

Capacity expansion and production costs models are best used iteratively in resource planning. Planners make necessary simplifications during the capacity expansion stage to decrease the problem size. Results from production cost modeling may reveal, for instance, that the capacity expansion model did not develop enough resources to provide ancillary services, omitted impacts of more detailed transmission systems, left unserved energy, or did not reflect well the contributions of variable resources such as wind, solar, and demand-side resources. For example, PacifiCorp found that portfolios developed in its initial capacity expansion model led to consistent capacity shortfalls when tested in a more granular dispatch model that explicitly accounted for operating reserve requirements (PacifiCorp 2023). Similarly, Public Service Company of Colorado found that the initial portfolio developed by the capacity expansion model was unable to satisfy reliability criteria (PSCo 2021).[35] In this case, using a supplemental resource adequacy modeling run identifies reliability shortfalls which can inform modifications for another set of capacity expansion runs.

An iterative approach to modeling is a best practice. Production cost runs help refine capacity expansion runs, and supplemental resource adequacy modeling sheds light on any reliability concerns. This produces more robust results and may allow the capacity expansion model to select and retire resources that minimize both long-term investment costs as well as short-term operational costs.

[35] Capacity expansion models are generally constrained by reserve margins. This approach generally ensures there is sufficient capacity to meet firm peak demand, but it does not answer questions about how a system will perform under extreme weather conditions, for example. Generally, separate stochastic reliability modeling is needed to answer such questions.

VI. Evaluating results and communicating transparently to regulators and stakeholders



The following section discusses best practices for presenting results to regulators and stakeholders, as well as selecting a preferred portfolio.

Best Practice 41. Use appropriate metrics to evaluate IRP results

Use appropriate metrics that have been intentionally designed to avoid skewing results towards a predetermined outcome.

After a utility has finalized its modeling results, the next step typically involves summarizing portfolio results in a matrix that presents utility performance across key metrics to facilitate comparison and communicate key differences across scenarios, often referred to as a scorecard. Scorecards can synthesize a large amount of information into a digestible format. In designing a scorecard, a best practice is for utilities to solicit feedback from stakeholders and regulators about the metrics included and whether the information is clear and unbiased.

Ideally, the process of selecting scorecard metrics would be an iterative process with stakeholder involvement. Utilities, regulators, and stakeholders can define core metrics at the outset of the IRP process that are aligned with region-specific needs and goals, such as pollutant emissions, rate impacts, customer satisfaction, economic development, and many others. Other important metrics can be added as the modeling progresses.

While there is no one-size-fits-all scorecard, there are common pitfalls to avoid. If a utility plans to use a weighting system to rank the relative importance of metrics, a pitfall to avoid is adjusting weights of metrics to reach a predetermined outcome. Instead, the utility can clearly communicate and justify the methodologies it uses for weighting, stakeholders can provide input, and regulators can review how weighting affects the selection of the utility's preferred portfolio.

In general, it is important to avoid using qualitative analyses that can be easily adjusted to preferentially highlight certain scenarios and thereby skew portfolio results. A good scorecard includes only those metrics that measure an explicit goal of the state, utility, or stakeholders, and excludes metrics that are already accurately reflected in PVRR results. All portfolios considered “should be safe and reliable, and to the extent that more or less system flexibility implies a cost, that cost should already (and accurately) be reflected in PVRR" (Synapse 2015). In addition, best practice is to avoid using extreme scenarios to skew portfolio rankings and the selection of the utility's preferred portfolio (for more information on preferred portfolio selection, see Best Practice 44 and Best Practice 45).

Following are examples of common metrics commonly included in a scorecard:

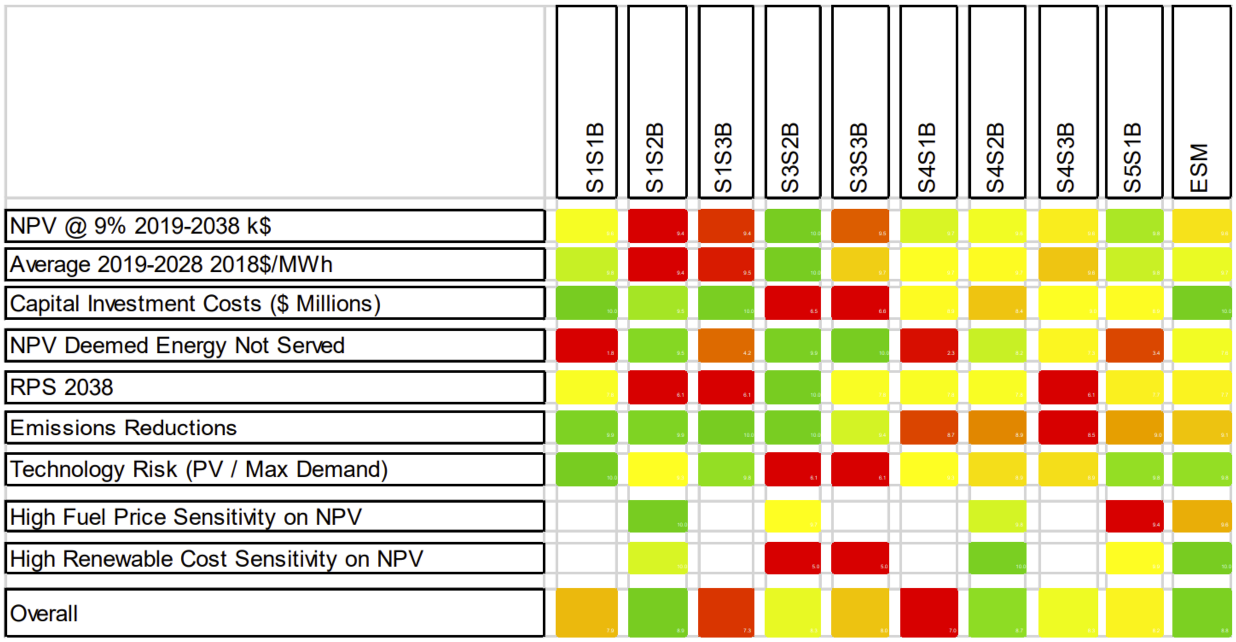
- **Cost.** Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms
- **Environmental sustainability.** Carbon emissions (total tons) and carbon intensity (tons per kWh), percent of generation from carbon-emitting resources vs. low carbon resources
- **Reliability.** If differentiated by portfolio, metrics could include LOLE and expected energy not served, among others that are relevant to the system being modeled
- **Cost exposure.** Exposure to fuel price volatility as measured by percent of generation provided by gas, coal, and oil plants
- **Market exposure.** Percent of load met through market purchases

The following examples highlight a scorecard that does not follow Best Practice 41, as well as a scorecard that does.

The Puerto Rico Electric Power Authority's (PREPA) 2018–2019 IRP scorecard does not follow best practice for clear presentation of results. The effort to create a qualitative, colorful scorecard resulted in a highly subjective, potentially biased, and confusing figure. The IRP explains that the scorecard (Figure 6) complements quantitative analysis of the PVRR of each scenario (Siemens Industry 2019). Elements that create room for misunderstanding include the following:

- Scenario names are not defined in the table or the text describing the figure, and the coded names provide insufficient summary information for each scenario.
- Metrics for each scenario are not clearly defined in the figure or descriptive text.
- Color-coding is not based on a defined or quantitative scale and obscures valuable information about the spread between and across variables.
- Weightings are not clearly defined, especially in relation to the "Overall" category and how it was calculated for each scenario.

Figure 6. Scorecard for PREPA's 2018–2019 IRP



Source: Recreated from Siemens Industry. Puerto Rico Integrated Resource Plan 2018–2019, Exhibit 8-7. Prepared for Puerto Rico Electric Power Authority.

The clearly presented scorecard in AES Indiana's 2022 IRP (see Figure 7) provides a good example of Best Practice 41.

Figure 7. AES Indiana 2022 IRP scorecard results

	Affordability	Environmental Sustainability						Reliability, Stability & Resiliency	Risk & Opportunity							Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis***	*General Cost Risk **Stochastic Analysis***	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1	$ 9,572	101.9	64,991	45,605	36.7	6,611	45%	7.95	$ 8,860	$ 11,259	$ 9,271	$ 9,840	5,291	$ 9,080	$ 10,157	222	$ 154
2	$ 9,330	72.5	13,513	22,146	7.9	1,417	55%	7.95	$ 8,564	$ 11,329	$ 9,030	$ 9,746	5,222	$ 8,763	$ 9,999	99	$ 193
3	$ 9,773	88.1	45,544	42,042	26.7	4,813	52%	7.86	$ 9,288	$ 11,462	$ 9,608	$ 10,237	5,737	$ 9,244	$ 10,406	195	$ 204
4	$ 9,618	79.5	25,649	24,932	15.0	2,700	48%	7.90	$ 9,135	$ 11,392	$ 9,295	$ 9,903	5,512	$ 9,104	$ 10,249	74	$ 242
5	$ 9,711	69.8	25,383	24,881	14.8	2,676	64%	7.57	$ 9,590	$ 11,275	$ 9,447	$ 10,039	6,088	$ 9,017	$ 10,442	55	$ 256
6	$ 9,262	76.1	18,622	25,645	10.9	1,970	54%	7.95	$ 8,517	$ 11,226	$ 8,952	$ 9,629	5,136	$ 8,730	$ 9,909	88	$ 185

Strategies

1. No Early Retirement
2. Pete Conversion to Natural Gas (est. 2025)
3. One Pete Unit Retires in 2026
4. Both Pete Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Pete Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

Source: Recreated from AES Indiana 2022 Scorecard Results, Figure 9-78.

AES Indiana based its evaluation categories (affordability; environmental sustainability; reliability, stability, and resiliency; risk and opportunity; and economic impact) on a set of pillars for electric utility service defined by a task force created by the Indiana General Assembly. This kind of intentional alignment with policy areas of interest helps ensure that the IRP is most informative for regulators (AES Indiana 2022). The scorecard clearly explains each category in detail in the text of the IRP and breaks it down into a set of quantitative metrics (e.g., PVRR, total portfolio carbon dioxide emissions). While the chart uses colors to indicate high and low values for each metric, it also includes quantitative values. In addition, the IRP immediately defines coded scenarios below the figure for stakeholder reference. The IRP also did not roll all metrics into a single score for each scenario, so there is no question of how weighting may slant results. While this eliminates one area of concern, it also puts the onus on AES Indiana to clearly explain why Strategy 2 was selected as the preferred portfolio rather than Strategy 5, which appears to result in similar outcomes overall.

Best Practice 42. Report results clearly

Ensure that modeling results are reported in a way that is transparent and easy to understand.

Effective IRPs report results in a way that is transparent and easy to digest, with sufficient information for effective stakeholder engagement, review of modeling methodology and findings, and regulatory oversight. At the same time, providing too much unprocessed data without proper synthesis can challenge all but the most sophisticated stakeholders to understand and provide input. This applies to scorecard matrices, as well as informational results that are not necessarily being used to evaluate or rank scenarios. Some stakeholders may have technical expertise to review raw data, and some may even want access to raw modeling data. Nevertheless, it is critical for the utility to summarize and synthesize results so that all stakeholders and regulators can understand the inputs, modeling process, and final results. A good example of a utility clearly reporting results and providing key information is Tucson Electric Power's 2023 IRP Dashboard (TEP 2023b).

Best practice IRPs provide a narrative for each scenario, alongside the following public information on results, at a minimum:

- Summary load and resources table for each portfolio, by year, for the full study period. The table summarizes all existing capacity by resource type, all new resource additions by resource type, the utility's demand forecast, and total capacity requirement including reserve margin—both firm (accredited) capacity and nameplate capacity. The table also includes the utility's firm capacity assumptions, including ELCC, for all resources.
- Summary table of generation (GWh) and capacity factors (percent) for each portfolio. The table summarizes generation by resource type and year, broken down by existing and new resources.
- Capacity graphs. These figures display firm capacity, nameplate capacity, and generation by resource type and by year.
- Table of air emissions. The table includes greenhouse gases and criteria pollutants by year for each portfolio.
- Table of plant retirements. The table shows retirement dates modeled for existing resources and indicates whether the date was programmed in or selected endogenously by the model through optimization.
- Table of new resources. The table clearly shows the quantity of new resources coming online each year, by resource type, showing both firm (accredited) capacity and nameplate capacity.
- Cost. Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms. While providing PVRR delta results from the preferred portfolio may also be useful, providing the final PVRR by scenario helps stakeholders contextualize the magnitude of the deltas.

Utilities can avoid providing stakeholders with an overwhelming number of metrics or scenarios while at the same time not obscuring important data with simplistic graphics.

Best Practice 43. Benchmark inputs and results to other utilities

While developing input assumptions and analyzing results, utilities can look to see how inputs and results of neighboring or similar utilities compare to each other. If there are major differences, these need to be justified or explained to stakeholders.

Over the next few years, dozens of utilities across the United States will produce and file IRP reports and annual updates. IRP practice could benefit immensely if utilities compared quantitative outcomes in their reports to provide data for benchmarks that stakeholders can use to assess appropriateness of IRP assumptions and results. Strong benchmarks require a large enough sample of utilities to serve as analogs that report customer number, peak demand, sales, and climate zone, among others, to produce normalized benchmark outputs. Examples of these quantitative outcomes include the expected percent of load growth for base and alternative scenarios, rates of adoption of renewable resources, speed of retirement of coal plants, and assumptions about resource costs and fuel prices. As part of its 2025 IRP process, Tennessee Valley Authority hired Deloitte to review the utility's 2019 IRP and conduct benchmarking of peer IRPs, including identifying key themes and trends to be considered in its current IRP (TVA 2024).

Looking Ahead: Publish standardized planning metrics for easy comparison

In addition to benchmarking against key planning assumptions in a public repository such as the Resource Planning Portal, the jurisdiction's utilities, regulatory commission, and stakeholders can agree on sets of standardized metrics that enable efficient comparison of IRP inputs and outputs. There is no current best practice in this area; these guidelines are aspirational.

For example, calculating, recording, and comparing average annual load growth might facilitate assessment of the reasonableness of load forecasts across utilities under normal conditions. A metric such as MW-kilometer of transmission capacity per MW of solar power may be a way to assess and compare the costs of renewable energy integration and support a discussion on assumptions that may be biasing estimated costs upwards or downwards. Regulators could define a set of standardized metrics that could be used to benchmark IRPs and support rigorous quantitative analysis of assumptions, parameters, and outputs. Under this potential best practice, utilities with assumptions that reasonably deviate from the norm would need to justify the differences.

Wilkerson et al. (2014)recognized the benefits of benchmarking for IRP a decade ago when they analyzed and compared plans filed by 38 load-serving entities. However, the same paper identified multiple shortcomings and inconsistencies in the collection and reporting of planning assumptions. Lawrence Berkeley National Laboratory started to address this issue by designing and developing the Resource Planning Portal, an online publicly available tool to collect key quantitative planning assumptions from IRPs (LBNL Planning Portal n.d.-a). The portal collects and shares key inputs and outputs for each IRP's preferred portfolio. Lab researchers seek to standardize the way IRP inputs and outputs are defined and recorded. Parameters recorded include annual consumption and peak load forecasts, annual energy efficiency and demand response resources, fleets of existing and planned generation and storage units, fuel prices, capital costs, and carbon costs.

Best Practice 44. Select a preferred portfolio

Select a preferred portfolio to guide near-term actions and justify any substantial deviations from the optimized portfolio.

Best practice IRPs identify a preferred portfolio, a collection of resource builds and retirements the utility selects based on one of the portfolios tested in the IRP process. The preferred portfolio reflects the utility's short- and long-term resource plan and serves as the basis of near-term procurement plans. A robust preferred portfolio is developed in the capacity expansion model and vetted comprehensively as part of the IRP process. Under this best practice, utilities avoid developing preferred portfolios outside the model or selecting a preferred portfolio that is a hybrid of multiple candidate portfolios at the end of the process—and not subject to the same level of sensitivity and risk analysis as other modeled portfolios. When the utility selects a preferred portfolio, it also is good practice to evaluate and explain any significant differences between optimized portfolios and the preferred portfolio. This is because the optimized portfolio is, by design, the least-cost portfolio for a scenario.

Traditionally, utilities select or design a preferred portfolio based on cost, as quantified by a portfolio's net PVRR. While net PVRR is a key pillar of scenario evaluation, and minimizing cost is important for utility customers, it is not the only differentiator between scenarios. Nor is it an automatic determinant of which examined portfolio the utility ought to select as the preferred portfolio. The portfolio may only appear least-cost in the context of the others the utility examined. If the modeling examined a narrow set of options, or used key inputs that were hardcoded, out of date, or poorly designed, the portfolio may not be the least-cost option available. Additionally, a portfolio may misleadingly appear least-cost because modeling did not fully capture and internalize associated risks and uncertainties (see Best Practice 29 and Best Practice 39).

Because the IRP process is tied to near-term procurement efforts, a preferred portfolio is essential to provide a clear short-term plan. If the utility does not select a preferred portfolio, it is likely not committing to a near-term procurement plan. Without a preferred portfolio, it is hard for stakeholders and regulators to focus their feedback and oversight. Considering the near-term action plan for resource procurement is an important part of the IRP review process. As discussed in Section VII of this report, IRP results can be important in other dockets, including in rate cases for determining cost recovery, in CPCN dockets for evaluating the reasonableness of new resource build proposals, in renewable portfolio standard compliance dockets for determining if resource plans meet state renewable energy requirements, and in fuel dockets for evaluating the reasonableness of utility fuel procurement and operational decisions.

The utility's selection of a preferred portfolio does not necessarily tie the utility to that portfolio, even in the short term, depending on how much and how quickly conditions change. But the preferred portfolio creates an important baseline for utility planning. The regulator may require the utility to justify changes to its resource plan, or why the plan has not changed if conditions shift markedly. Some states, such as Virginia (Virginia General Assembly, n.d.) and Oregon (Oregon 2021) require utilities to file IRP updates annually or when plans change significantly.

Best Practice 45. Model state goals and priorities in the preferred portfolio

Align the preferred portfolio with articulated state goals and priorities.

It is common for regulators to require specific IRP elements. A typical example is requiring the utility to select a "preferred portfolio," as discussed above. While the requirement to select a preferred portfolio does not prescribe resources that must be included, in many states, regulators require utilities to model specific scenarios and sensitivities to inform the preferred portfolio and make the results publicly available in a useful manner. Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.

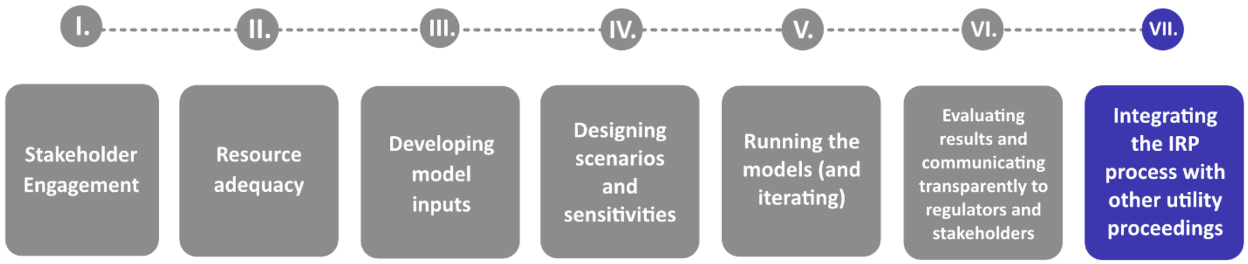
For example, the Arizona Corporation Commission required Arizona Public Service to run more than 10 specified scenarios for its 2023 IRP, including a minimal load growth scenario, rapid DSM adoption, and a variety of sensitivities that examined early retirement of the Four Corners coal power plant. While the utility followed through on this direction, some parties ultimately had concerns with how the utility designed and presented some of the scenarios—particularly the early coal plant retirement scenarios (Sierra Club 2024).

Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.

Arizona Public Service developed the required early retirement sensitivities by altering the retirement date of Four Corners in a reference case and then allowing the model to re-optimize. This method showed that early retirement in 2028, for example, would cost $139 million less than the reference case, which retired the plant in 2031. Separately, the utility designed a preferred portfolio, which maintains the 2031 retirement date but differs from the reference portfolio in other ways. Arizona Public Service concluded that this portfolio would be $357 million cheaper than the reference portfolio. The utility presented this information as evidence that the preferred portfolio would cost less than the portfolio representing the early retirement date.

Although Arizona Public Service followed the commission's direction in modeling additional scenarios, the scenarios differed in critical ways from the preferred portfolio. It is also unclear why the utility did not test earlier retirement dates for Four Corners using its preferred portfolio, not just the reference portfolio. Comparing an early retirement sensitivity in the reference portfolio to a 2031 retirement in the preferred portfolio is not an apples-to-apples comparison. In addition, since early retirement in the reference portfolio yielded lower costs, an early retirement sensitivity for the preferred portfolio also would have resulted in lower costs. Such analysis would have provided a full picture of potential cost savings across portfolios (Sierra Club 2024). In situations like these, regulators can scrutinize the scenarios modeled by the utility and request that the utility run additional scenarios that align with the commission's original goals.

VII. Integrating the IRP process with other utility proceedings



IRP scenario analysis requires careful design of modeling assumptions and possible pathways. It produces a wealth of useful data that has implications for the power system as a whole. Modeling assumptions that are intentionally prepared to easily port them into other modeling exercises have important consistency and transparency benefits. The following best practices apply to using IRP scenario results to inform other regulatory proceedings.

Best Practice 46. Use IRP results to inform an Action Plan and utility procurement processes

Integrate resource planning and related procurement processes.

A primary purpose of IRP scenario results is to inform utility procurement processes. In practice, this translates to utilities using IRPs to support an RFP, CPCN, or other procurement process. The first step in this direction is for the IRP to include a well-designed Action Plan.

The Action Plan is a section in the IRP document that describes near-term actions the utility will take over the next 1 to 3 years related to implementing outcomes in the preferred portfolio. An effective Action Plan is supported by the results, analysis, and conclusions of the IRP. It clearly states the action the utility plans to undertake to procure resources, including issuing RFPs, securing any required CPCN, initiating siting and licensing process, and deploying or expanding energy efficiency and demand response programs (LBNL 2021d). The Action Plan outlines how the utility plans to comply with specific regulatory requirements (e.g., a renewable portfolio standard target for an upcoming year) and proposes any regulatory changes that may be needed to support the development and execution of the preferred portfolio. In cases where the IRP recommends a wait-and-see strategy for risk management, the Action Plan can include near-term milestones to pursue the strategy (e.g., in an IRP update report, describe progress on a certain component of the IRP that was deemed uncertain). Finally, the Action Plan can outline near-term actions the utility identified to improve its analytical capabilities, such as developing certain datasets, working with vendors to implement new tools, or collaborating with stakeholders to refine input assumptions. PacifiCorp's 2023 IRP provides an example of a clear Action Plan, using a table format to identify and organize near-term actions for specific units, projects, and regulatory requirements (PacifiCorp 2023).

A best practice for procurement is to use the same inputs and assumptions reviewed by regulators in the IRP process, unless there are significant changes in market conditions. In cases where the investment environment has changed from what the utility assumed in the most recently filed IRP, the utility can leverage scenario results to support departures from the preferred portfolio—given that scenarios are least-cost expansions of the bulk power system under different assumptions. If no existing scenarios match current investment conditions, the utility can conduct new scenario runs to support procurement decisions and ensure these procurement-specific scenarios inform the next IRP filing.

Best Practice 47. Use IRP results to inform other types of planning

Use IRP results to inform evolution of planning for bulk power systems and distribution systems.

IRP scenario results offer a range of potential pathways for evolution of the bulk power system. Several other planning processes would benefit from information on these pathways:

- Planning for distributed energy resource programs and virtual power plants. Wholesale electricity prices and new build capacity costs—especially when developed with thoughtful spatial resolution (V.Best Practice 32)—can be used for avoided cost calculations that serve as the basis for incentives for distributed energy resource programs. These same data can also inform assessments and planning for virtual power plants.
- Renewable Portfolio Standards planning. Comparison of system costs across pathways that offer different penetration levels of renewable resources, with different emissions profiles, can inform renewable energy certificate price forecasts and emission abatement cost estimates.
- Transmission planning. Transmission expansion decisions made by the capacity expansion model can inform more detailed regional transmission expansion studies.
- Distribution system planning. IRP assumptions and results on the relative balance between utility-scale and distributed energy resources can inform distribution system analysis—in particular, distributed energy resource adoption and operation scenarios. IRP scenario assumptions and model results that capture interactions between distributed and bulk power system resources are critical inputs into distribution system planning analysis. Conversely, high levels of distributed energy resources at the distribution level impact the need for bulk power system resources, as well as bulk power system operation. A growing number of states require integrated distribution system planning (LBNL n.d.-b), a decision framework that addresses interactions across planning domains and enables formulation of long-term grid investment strategies to address policy objectives and priorities, consumers' needs, and evolution at the grid edge (U.S. DOE n.d.).

Best Practice 48. Evaluate bill impacts

Evaluate bill impacts by customer class as part of the IRP process.

IRP modeling evaluates how resource decisions impact total system costs, not how decisions impact cost recovery and cost allocation. If a resource planning decision is likely to have a significant impact on system costs and customer bills, ignoring rate impacts during an IRP may lead to unexpected impacts on utility customers. Examples of such decisions are large buildouts of supply-side resources to meet data center load growth and retirement decisions for aging power plants.

First, data center load is expected to grow dramatically in many parts of the country. The attractiveness of these locations to prospective data centers is based in large part on current low power costs. But to meet projected data center load, utilities are proposing to build a substantial quantity of new resources and continue to operate aging resources. The new power system will not look or cost the same as the current system, and therefore electricity rates are not likely to be the same. Regulators need information on what portion of bulk power system costs the data centers are likely to pay, and what portion residential and other customer classes will pay to make well-informed decisions regarding approval of new supply-side resources. This is particularly important in the case where the utility considers data center load as a potential market to justify new generating resources, even though the load would be located outside the utility service territory, where the utility has no obligation to serve (GPC 2023 Response to STF-JFK Data Request 4-4).

Second, for aging fossil fuel plants, utilities can analyze different ratemaking options to determine retail rate impacts and impacts on retirement timelines. Once a utility has identified in an IRP proceeding an economic early retirement date, it can explore all ratemaking options under which to economically retire that unit. Such analyses can be included as part of the IRP process, or the analysis may be done partially or entirely outside of an IRP proceeding—for example, in a rate case.

Typically, utilities depreciate assets according to a depreciation schedule aligned with the useful life of the resource. Ideally, by the time the asset retires, its value has been fully depreciated and it is removed from rate base. But when an asset becomes uneconomic before its scheduled retirement date, the utility and the regulator have options for addressing the remaining plant balance. Generally, maintaining the existing depreciation schedule while retiring a plant early is not an option, given the misalignment it would perpetuate between when costs are incurred and when they are recovered through rates. Stated another way, it is not good rate design practice to spread cost recovery out over a period of time when the asset is no longer providing value to utility customers.[36]

Regulatory options include the following:

1. *Status quo depreciation and retirement.* The utility can continue to operate the unit for its planned lifetime, regardless of economics, to allow the utility to continue to collect a full rate of return on the asset. The utility will continue to spend capital to maintain the asset, which will be

[36] In some states, such practice is unlawful. For example, Oregon ORS 757.355 states, "...a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." (Oregon n.d.).

added to rate base, and will continue to pass costs onto utility customers for the originally planned lifetime.

2. *Accelerated depreciation and retirement*. A utility can request to adopt an accelerated depreciation schedule to more closely align the depreciation schedule for the resource with a retirement date that is earlier than the planned lifetime. This can cause rate shock if the change in schedule is too drastic (e.g., going from 15 years remaining lifetime to 5 years). To mitigate the shock, the utility can adjust the pace of accelerated retirement.
3. *Disallowance.* The regulator can disallow recovery of some or all undepreciated costs of the asset before the retirement date, with shareholders picking up the cost. However, this is more common for specific capital investments that are deemed imprudent, rather than for remaining balances for plants determined to be prudent at the time of the original investment.
4. *Regulatory asset.* The utility can turn the remaining plant balance into a regulatory asset with a depreciation date somewhere between the original date and the current retirement date. The negotiated rate of return would be lower than what the utility was collecting originally.
5. *Securitization or other alternative finance mechanism.* The utility can use securitization (where allowed by law) or another alternative financing mechanism, such as a loan from the Energy Infrastructure Reinvestment program under the IRA, to retire the plant early. The rate of return the utility receives on the asset would be lower than it was receiving before, but cost recovery of the remaining balance is more secure. For example, after its 2019/2020 IRP, CenterPoint Energy Indiana South pursued securitization of its A.B. Brown coal units as part of its generation transition plan (CenterPoint Energy 2023).

Best Practice 49. Consider energy justice comprehensively

Factor energy justice into all parts of an IRP process and engage impacted communities.

Energy justice considerations are best factored in throughout the IRP process, from the time planners choose a model, develop input assumptions, and run scenarios, to when they present results to stakeholders and regulators. While energy justice is not a new concept, it is an emerging field of inquiry—in part because much of the data needed to fully estimate the comparative impacts of portfolios on impacted communities are not readily available. An emerging best practice for utilities is to begin to collect data on impacts of concern (e.g., high energy burdens, health impacts from emissions, poor system reliability) for priority populations (e.g., disadvantaged communities, minorities, customers with low incomes, customers who are medically dependent on electric service) during IRP processes. As the utility collects more data, it can be used to inform more detailed integration of energy justice considerations in future IRP cycles. Some jurisdictions are beginning to require this level of detail. For example, Washington state law requires electric utilities to file a clean energy implementation plan every 4 years. By law, the plan must identify highly impacted communities and vulnerable populations, as well as quantify customer benefits and reduction of burdens (Washington State Legislature 2022).

A comprehensive discussion of how energy justice factors into various best practices discussed in this report is outside our scope. Resources on this topic include a recently published report by Lawrence Berkeley National Laboratory and Synapse on distributional equity impacts of utility programs for energy efficiency and other distributed energy resources, which could be useful for informing equitable decision-making in the context of resource planning (LBNL and Synapse 2024).

RMI highlights several best practices for addressing energy justice in IRPs, such as the following (RMI 2023):

- Plan for community transition associated with asset retirements, including job losses, increased unemployment, loss of tax revenue, and reduced property values.
- Estimate comparative rate impacts of portfolios.
- Define and map disadvantaged communities to assess impacts, using tools such as Climate and Economic Justice Screening tool (CEJST), developed by the U.S. Council on Environmental Quality (U.S. CEQ CEJST n.d.), and Environmental Justice Screen (EJScreen) developed by the EPA (U.S. EPA EJScreen 2014)
- Factor community acceptance into resource availability and feasibility of plans.

Additionally, resource planners can also consider the following actions:

- Provide translation services and IRP modeling results in multiple languages suited to a utility's customers (refer to Best Practice 1 on creating an inclusive stakeholder process).
- Factor in resilience and disproportionate impacts during extreme events (Synapse 2021).
- Explicitly define how programs for energy efficiency and other distributed energy resources deployment support energy justice objectives.
- Define energy justice metrics and quantify how well each portfolio scores with respect to these metrics (see Step 4, Develop DEA metrics, in the Distributional Equity Analysis Practical Guide for information on how to do this) (LBNL and Synapse 2024).
- Publish and map pollutant values for existing assets and potential portfolios.
- Develop environmental and health cost scenarios and analyze portfolio impacts.

Hawaiian Electric Company is among utilities that have started to incorporate energy justice practices into resource planning processes. The utility mapped locations for microgrid hosting based on criticality (emergency or critical loads, facilities or infrastructure), vulnerability (areas that are prone to natural hazards, are inaccessible, or have experienced high outage rates), and societal impact (locations with social implications). For the societal impact criterion, Hawaiian Electric mapped disadvantaged communities using EJScreen (Hawaiian Electric 2022).

Figure 8 provides additional resources (clickable) with information on advancing energy justice in an IRP process.

Figure 8. Additional resources on advancing energy justice in an IRP process—Click to view

The Spectrum of Community Engagement to Ownership (Facilitating Power 2020)	The Energy Equity Playbook. ILLUME (Illume Advising 2021)	Initiative for Energy Justice: Justice in 100 Metrics (Lanckton and DeVar 2021)
State Energy Justice Roundtable Series: Participation in Decision Making. National Association of Regulatory Utility Commissioners (NARUC 2023)	Advancing Equity in Utility Regulation, Future Electric Utility Regulation Report. Lawrence Berkeley National Laboratory (LBNL 2021 Advancing Equity)	Designing Equity-Focused Stakeholder Engagement to Inform State Energy Office Programs and Policies. National Association of State Energy Officials (NASEO 2020)
Community Energy Planning: Best Practices and Lessons Learned in NREL's Work with Communities (National Renewable Energy Laboratory 2022)	Power Play: Actions for New England's Equitable Energy Transition (Synapse Energy Economics 2023)	Equity in Sustainability: An Equity Scan of Local Government Sustainability Programs (Urban Sustainability Directors Network 2014)

Best Practice 50. Consider the evolving natural gas distribution industry

Track the technical, financial, and regulatory developments of natural gas distribution firms operating in the electric utility's service territory to improve coordination.

Electricity IRPs and gas distribution system planning are closely linked in multiple ways. For example, in areas of the Northeast that have limited access to natural gas, winter gas demand for building heating is creating emerging reliability challenges for natural-gas-fired power plants. Looking to the future, growing electrification of customer technologies such as water heaters, space heating systems, and cooking appliances is expected to increasingly transfer energy demand from gas distribution systems to electricity systems. This may change the dynamics of natural gas availability in places such as the Northeast and have wider effects nationwide on electricity IRPs and gas distribution planning. Crucially, economic decommissioning of natural gas distribution system assets, due to reduced gas demand, would prompt unexpected switching to electrified end uses across residential and commercial customers.

A best practice for electric utilities would be to track the technical, financial, and regulatory developments of natural gas distribution firms operating entirely or partially in their service territories. The IRP section that describes the utility's planning environment could describe the status of these natural gas distribution firms and potentially inform a sensitivity analysis for load forecasting that includes larger blocks of customers shifting to electrified end uses due to natural gas service phase-out.

Looking Ahead: Integrate electricity and natural gas industry planning

An emerging practice points towards integration of electricity and natural gas industry planning to ensure improved coordination for optimal societal outcomes, both economic and distributional. A potential decrease in customers on gas distribution systems would translate to fewer customers available to pay for their maintenance. This may increase the financial burden on remaining gas customers, which raises energy justice concerns if higher-income customers electrify first and the risk of higher gas rates falls on those who are already disadvantaged. For example, the state of Washington issued a rulemaking decision mandating Integrated System Planning across electricity and natural gas (WA UTC 2024).

Conclusion

Resource planning is challenging. During times of transition and market uncertainty it becomes even harder. It also becomes more important. As we leave behind a decade of flat load growth and look forward to projections of record load growth and continued decarbonization and electrification, robust resource planning is necessary to identify economic and reliable resource plans to serve utility customers, balancing uncertainties and risks facing the U.S. power sector today.

This guide outlines a list of 50 best practices for resource planning. They cover stakeholder engagement, resource adequacy, model input development, scenario and sensitivity design, modeling, portfolio and result evaluation, and integration of the IRP process with other proceedings.

Some best practices are straightforward and simple to implement while others require a considerable shift and reform of the resource planning process. All of these best practices represent actions or approaches we have seen implemented, or at the very least studied, by one of more utilities. Implementation steps vary, based on each utility's current planning practice.

The objective of this guide is to provide concrete steps for progress. While an ideal IRP process incorporates all best practices, IRP reform takes time. Utilities can use the guide to develop a roadmap and plan for how to improve the robustness of their IRP processes. Stakeholders can use the guide to help prioritize their engagements in the IRP process and identify where utilities are falling short. And regulators can use the guide to evaluate the reasonableness and robustness of each element of the IRP process and decide where to direct utilities to shift their approach to meet a higher standard for planning.

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