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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 2024). 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.

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[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 2024b). Typical current IRP modeling approaches may oversimplify aspects of the design, operation, and value of storage resources, missing their full value stack (RMI 2015). 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 2021d). 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).

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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 2021d). 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 2020). 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 2021d). 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

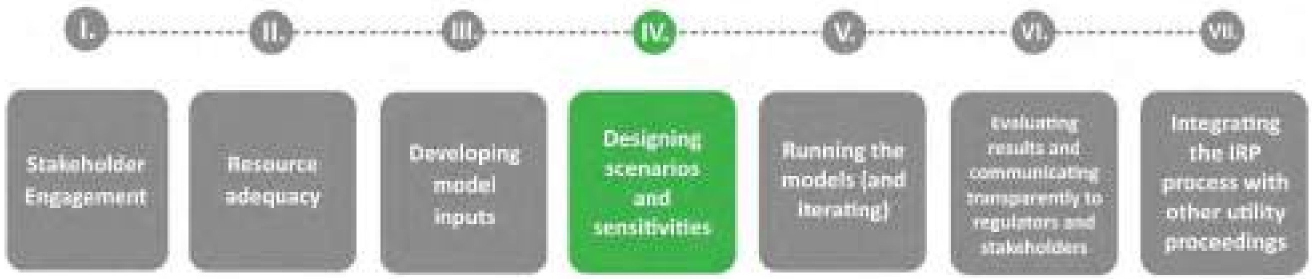
Properly justify interconnection costs and constraints modeled for new generation resources at the bulk power system level.

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.

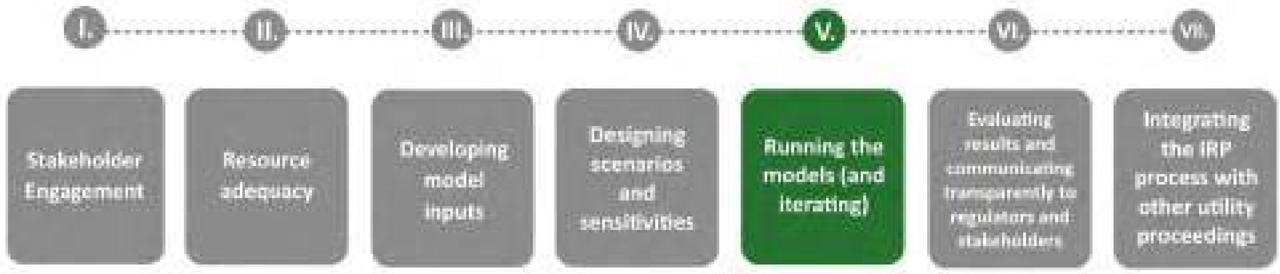
Modeling the impact of proposed regulations can also inform intelligent regulatory design. When EPA publishes new environmental rules, the agency solicits feedback from industry. Incorporating proposed environmental regulations into IRPs can provide quantitative evidence to support industry feedback.

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.-c) and RPM (NREL RPM n.d.-d) capacity expansion models and the Sienna production cost model (NREL Sienna n.d.-e), 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.

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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

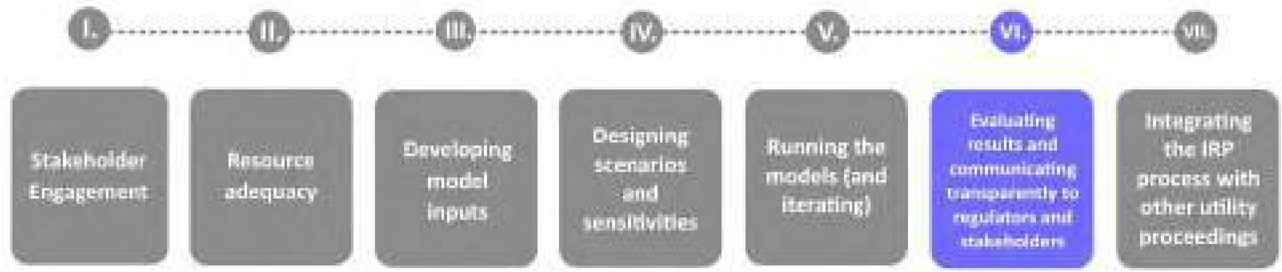
Use capacity expansion and production cost models iteratively to help refine results.

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:

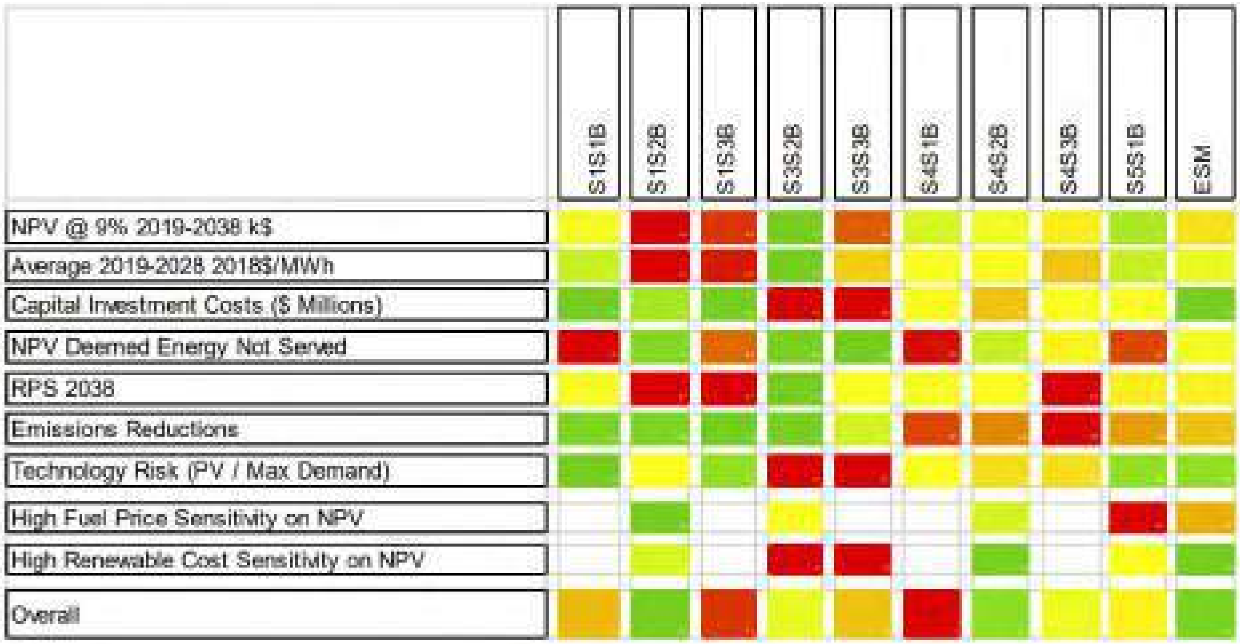
- **Cost.** Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms
- **Environmental sustainability.** Carbon emissions (total tons) and carbon intensity (tons per kWh), percent of generation from carbon-emitting resources vs. low carbon resources
- **Reliability.** 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.

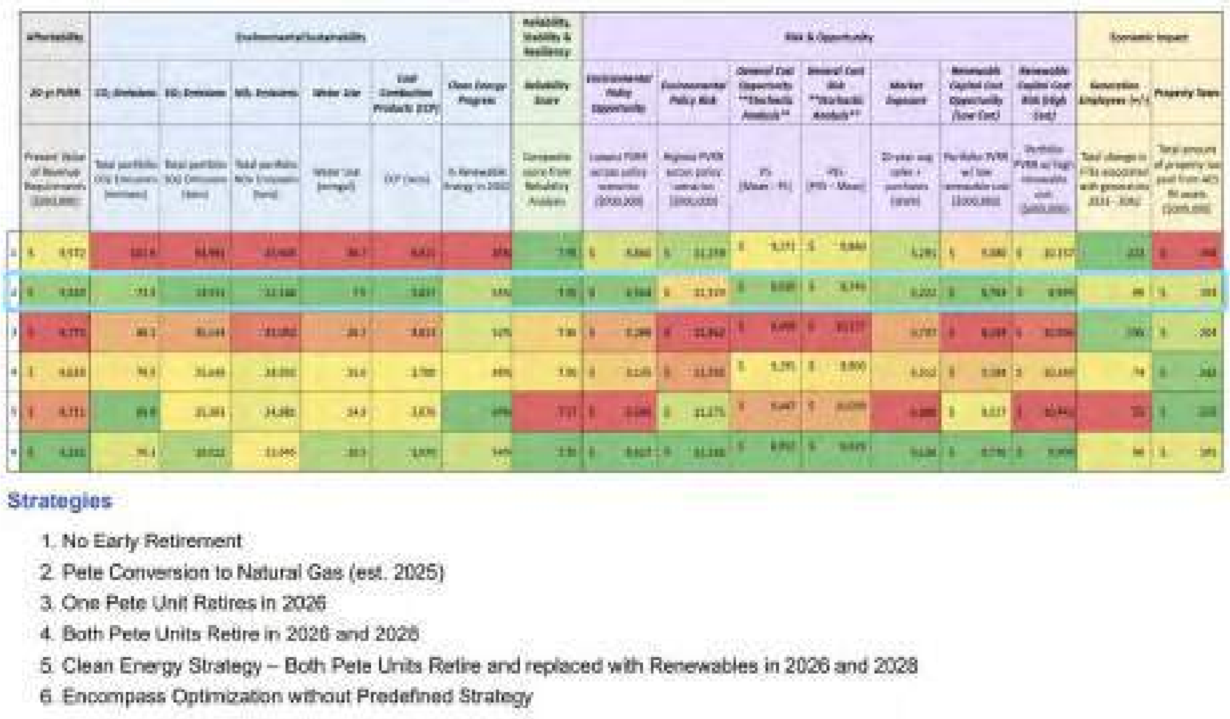
Figure 6. Scorecard for PREPA's 2018–2019 IRP



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



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.

EXHIBIT 67
Part 6
(Pages 76–90)

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.

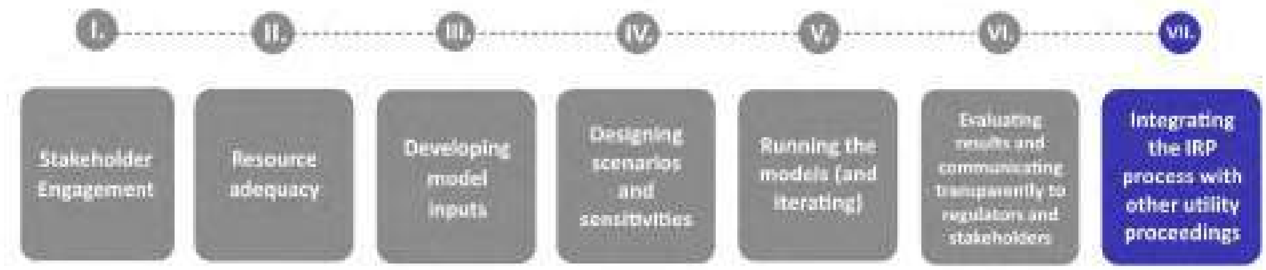
For example, the Arizona Corporation Commission required Arizona Public Service to run more than 10 specified scenarios for its 2023 IRP, including a minimal load growth scenario, rapid DSM adoption, and a variety of sensitivities that examined early retirement of the Four Corners coal power plant. While 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 2021c). 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 planning for bulk power systems

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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EXHIBIT 68

Trump has vowed to make coal king again. How's it going?

By HANNAH NORTHEY (HTTPS://WWW.EENEWS.NET/MEET-THE-TEAM/HANNAH-NORTHEY/) | 09/26/2025 01:33 PM EDT

Energy analysts say upticks in coal production and demand are only temporary fluctuations, despite the administration barreling ahead with efforts to boost production and market share.

President Donald Trump signs an executive order to boost the coal industry at the White House on April 8. Andrew Thomas/Middle East Images/AFP via Getty Images

President Donald Trump is scoring political points on the right with his aggressive push to revive the struggling U.S. coal industry.

"It's not just 'drill baby drill,' it's also 'diiig baby diiiig,'" Dagen McDowell, the host of Fox Business, said on "The Bottom Line" last month. "The president [is] bringing coal back."

Is he, really?

Trump has made rescuing coal a top priority in his second term, something he promised and failed to do during his first term. The administration is approving mining leases, fast-tracking permits for mines and forcing some coal-fired power plants (https://subscriber.politicopro.com/article/eenews/2025/09/25/trump-energy-department-eyes-new-must-run-orders-for-power-plants-ee-00580890) to remain open while exempting others from EPA rules. But since the Obama administration's big crackdown, more than 300 power plants — the primary destination for U.S. coal — have stopped burning coal while coal production (https://www.eia.gov/coal/annual/pdf/tableES1.pdf) has fallen by half since 2006.

Trump officials are pushing to reverse course; opening massive tracts of public land to coal mining, largely in the West; and quickly approving projects that could yield more than 800 million additional tons of federal coal for power plants and export markets in states like Wyoming, Montana, North Dakota and Utah.

The administration also plans to lift a Biden-era ban (https://public-inspection.federalregister.gov/2025-12672.pdf) on coal leasing in the Powder River Basin, a region of rolling grasslands in southeastern Montana and northeastern Wyoming that pumps out 40 percent of the nation's coal but has seen production crater since the 1990s. It's the United States' main source of thermal coal to fuel power plants.

At the same time, DOE is trying to scrub coal's dirty image; and offering up $200 billion in loans (https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing) for infrastructure, including coal-powered electricity generation. EPA also joined the fray, exempting a host of aging coal plants from federal environmental air and water regulations while clawing back climate regulations.

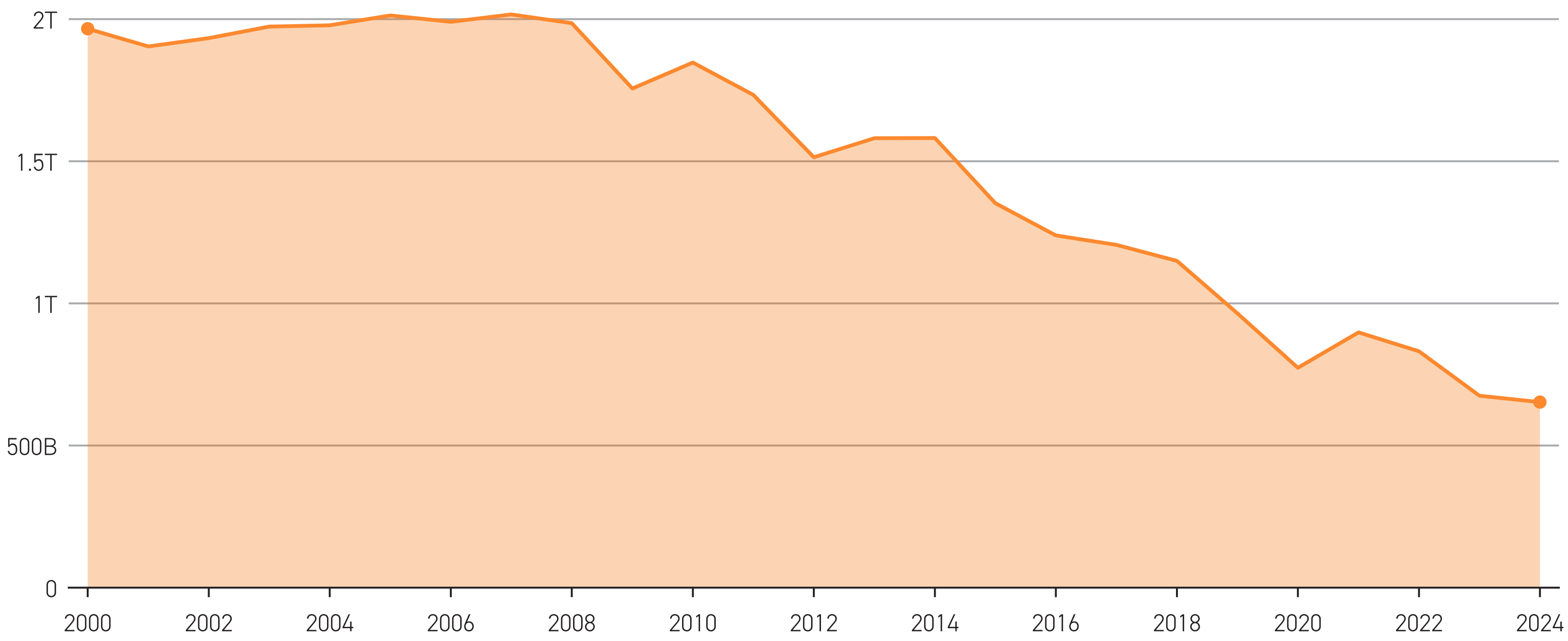
"President Trump has expedited the expansion of beautiful, clean coal – a critical energy source that Joe Biden tried to eradicate under his radical climate agenda," Taylor Rogers, a White House spokesperson, said in a statement. "President Trump has unleashed coal because its capabilities allow us to supply more energy, lower electricity prices, and stabilize the grid while creating thousands of high paying jobs."

Pro-Trump coal boosters say an upswing has begun.

Production of thermal coal used for power generation and metallurgical coal for steelmaking is forecast to rise this year compared to the prior year. At the same time, demand for coal to burn for electricity is also up, and coal-fired power plants are expected to generate 9 percent more power for all of 2025 compared with last year, the first year-over-year increase in coal generation since 2021, according to federal data. They also point to eye-popping projections for electricity demand with the proliferation of data centers, and the growing string of decisions in states like Arizona, Kentucky and New Mexico (https://subscriber.politicopro.com/article/eenews/2025/08/11/crushing-power-demand-breathes-new-life-into-n-m-coal-plant-00499577) to delay the retirement of coal plants that need fuel from the Powder River Basin.

Coal-fired power fell 67% as utilities shifted to gas, renewables

Kilowatt-hours of net electricity generation, all sectors



Source: U.S. Energy Information Administration
Claudine Hellmuth/POLITICO

“Obviously, the demand is not where it was in the early 2000s but there is still demand,” said Travis Deti, executive director of the Wyoming Mining Association, whose members include mining giants Peabody, Core Natural Resources and Navajo Transitional Energy. “We might not have enough coal [leases] to meet the demand going forward,” said Deti.

Michelle Bloodworth, the president of America’s Power, a trade group representing coal interests, said her members want to preserve every megawatt of existing coal-fired generation and argued those plants are needed for grid stability and make economic sense, especially when the grid is strained. Some power plant owners, she said, are talking about building new facilities and making investments given the forecasts for power demand and support from the Trump administration. The governor of coal-heavy West Virginia this week also called for the construction (https://subscriber.politicopro.com/article/eenews/2025/09/15/morrisey-hypes-new-wv-coal-plants-to-power-ai-ew-00563006) of new coal plants.

“There’s a lot of units that are not running, certainly at capacity,” she said. “There’s a lot you can do to make a coal plant, an existing coal plant, almost a new cutting-edge technology. You just have to invest in it.”

But experts say the temporary upticks in coal production and demand aren’t proof of a bigger trend, and instead temporary fluctuations driven by the price of gas and weather.

Andy Blumenfeld, a coal analyst at McCloskey by OPIS, said almost 8,000 megawatts of coal-fired generation are scheduled to either close or shift to natural gas by the end of the year. That number includes a 1,500-MW plant in Michigan that the DOE has ordered to continue (https://subscriber.politicopro.com/article/eenews/2025/08/21/trump-extends-order-forcing-mich-coal-plant-to-run-00517490) operating.

That downward power trend is extending into mining and leasing on federal land, where active coal leases in the U.S. have steadily declined from almost 500 in the 1990s to about 280 two years ago, according to federal data (https://www.blm.gov/sites/default/files/docs/2024-05/energy_coal_NationalCoalTable_FY23.xlsx). Blumenfeld also said coal miners in the Powder River Basin have already locked up 16 years’ worth of leasing and the administration isn’t likely to drive a surge of new activity.

Brendan Pierpont, director of electricity modeling at Energy Innovation, a nonpartisan energy and climate policy think tank, agreed. He said coal is in a long-term structural decline that’s unlikely to ease even with Trump’s intervention or the rush to build new power-hungry data centers.

That’s because the country’s existing coal fleet is aging — the average age hovering around 42 years — as maintenance and fuel costs rise, he said. There are no plans for new facilities on the horizon, Pierpont said, and utilities and data center developers looking for the cheapest and fastest sources to power demand are moving toward storage and gas peaking units, not coal.

“I don’t see anything that’s going to kind of stop this long-term trend, because it’s really driven by these fundamental economic factors,” said Pierpont. “These are older, less economic clunkers, essentially, and … it’s pretty clear that economics there are going to be a limiting factor.”

America’s mining hub

Trump’s push to expand coal mining on public land could have the biggest impact in the Powder River Basin, which covers 20,000 square miles (https://pubs.usgs.gov/publication/pp1809) — almost the size of West Virginia.

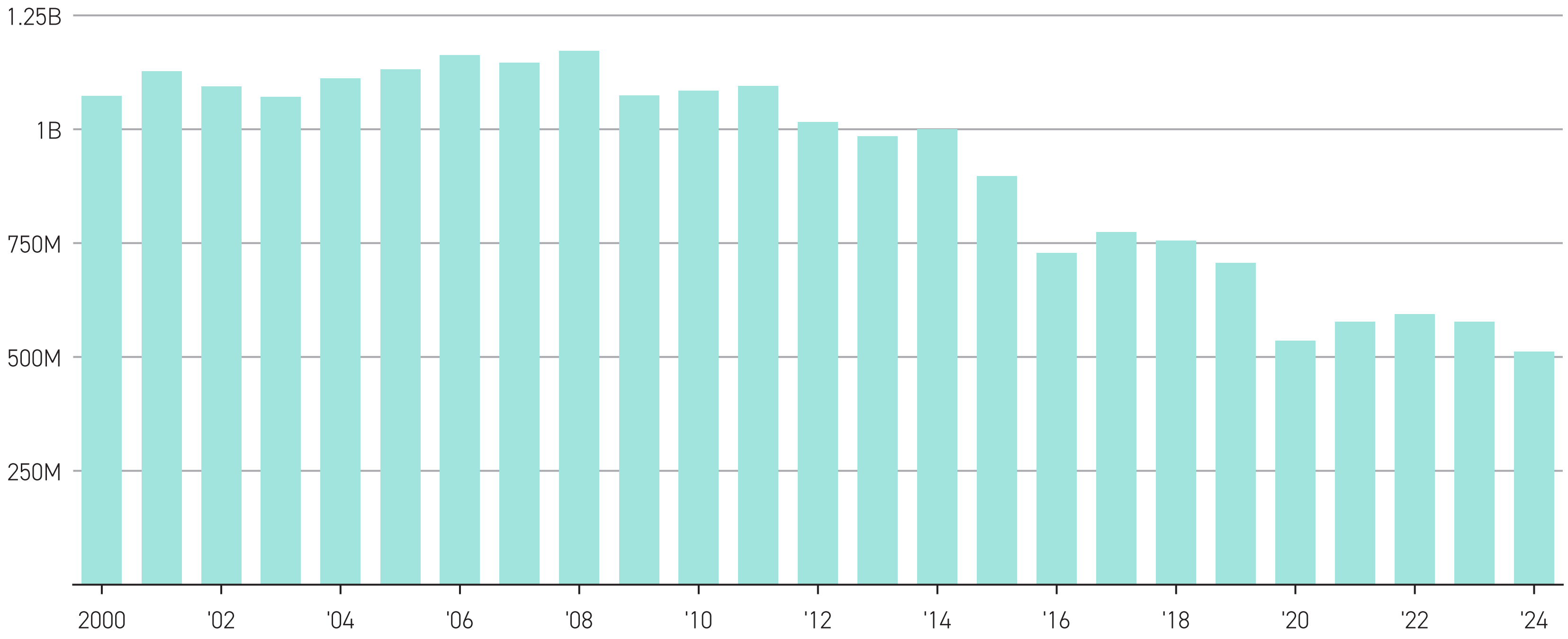
Trump officials in July announced they're considering lifting a ban the Biden administration imposed on leasing in the Powder River Basin to determine whether the policy aligns with the president's declaration of an energy emergency and executive orders that call for unleashing fossil fuels. The Biden administration argued that barring activity in the mining hotbed would safeguard the nation from an uptick in greenhouse gas emissions and cited waning demand for coal.

At the time, Todd Yeager, the field manager for the Bureau of Land management's Buffalo office in Wyoming, said the agency (https://subscriber.politicopro.com/article/eenews/2024/11/27/biden-halts-new-powder-river-basin-coal-leasing-00191905) was cutting off access to 48 billion short tons of coal in the basin, and asserted that production in the Cowboy State had declined since peaking in 2008 and that federal data showed it would continue to dwindle.

The last coal-fired power plant built in the continental U.S. came online in 2013, BLM said at the time. More are poised to retire, and Wyoming Powder River Basin coal was shipped to 10 fewer power plants in 2023 than in 2021. The agency also blamed a lack of demand and noted that two coal leases the BLM oversees in Wyoming had been paused for years due to "lack of miner operator interest."

Coal production dropped by more than half since 2000

Coal production, short tons



Source: U.S. Energy Information Administration
Claudine Hellmuth/POLITICO

Jeremy Nichols, a senior advocate with the Center for Biological Diversity, said that many of the active coal leases have long been on the books and there's no proof companies are still interested in mining federal coal, given the costs.

"These approvals were just sitting out there, and it's easy to score political points … but it opens the question of, 'OK, now what happens? Is it all political theatrics or is there legitimate interest here?'" Nichols asked.

Deti with the Wyoming Mining Association blamed the Obama and Biden administrations for blocking leasing and shelving projects in the basin over climate concerns. "When we pushed back against the moratorium, the response was 'the demand's not there,'" said Deti. "Well, if the demand isn't there, why do you need a moratorium?"

Republican governors in Wyoming and Montana sued the BLM (https://wyofile.com/wyoming-montana-sue-feds-to-repeal-powder-river-basin-coal-leasing-ban/) to overturn the ban. Now they're urging the Trump administration to take action. Montana's delegation has also succeeded in movinglegislative language (https://subscriber.politicopro.com/article/eenews/2025/07/11/montana-republicans-introduce-cra-to-kill-land-use-plan-00447671) to undo the prohibition through the House and into the Senate, where it's awaiting action.

Blumenfeld said the Trump administration is advancing leases in states like Utah and North Dakota that had been tripped up with litigation tied to inadequate consideration of climate change. Empowered by recent Supreme Court decisions that limit those reviews, Blumenfeld said federal workers under Trump are now quickly working through the backlog.

Yet even if the Trump administration fast-tracks projects and lifts the leasing ban, Blumenfeld said a leasing bonanza is unlikely and that producers have more than a decade's worth of coal locked up — an amount that could last longer as more coal plants shutter.

Obtaining a lease also requires both an upfront reserve payment or a "bonus bid," as well as royalties for each ton of coal produced and reclamation bonding requirements, Blumenfeld said. Those costs pose hurdles for coal companies, even though the GOP megabill reduced royalties from 12.5 percent to 7 percent, he said.

"Some mining companies may be facing a more immediate need to obtain new reserves. Given it has taken up to 10 years to obtain a lease in the past, some companies might be interested in leasing new reserves because of the reopening window at the BLM," said Blumenfeld.

"I do not think there will be a rush to lease new reserves," he said.

‘Put miners back to work’

When Trump hatched his plan to revive coal in April, he also vowed to bring back the nation’s struggling fleet of coal plants.

“We’re bringing back an industry that was abandoned,” said Trump at a signing ceremony (https://www.youtube.com/watch?v=1TfJUn2VxM4) in April, flanked by coal miners donning hard hats and Republicans from a slew of Western states.

At the event, he inked four executive orders to open new leasing for mining coal on federal land, to loosen emission standards for coal plants, and to direct the Justice Department to take legal action against state laws and regulations that impede energy development. The directives also laid the path for DOE to take executive action to keep coal plants online.

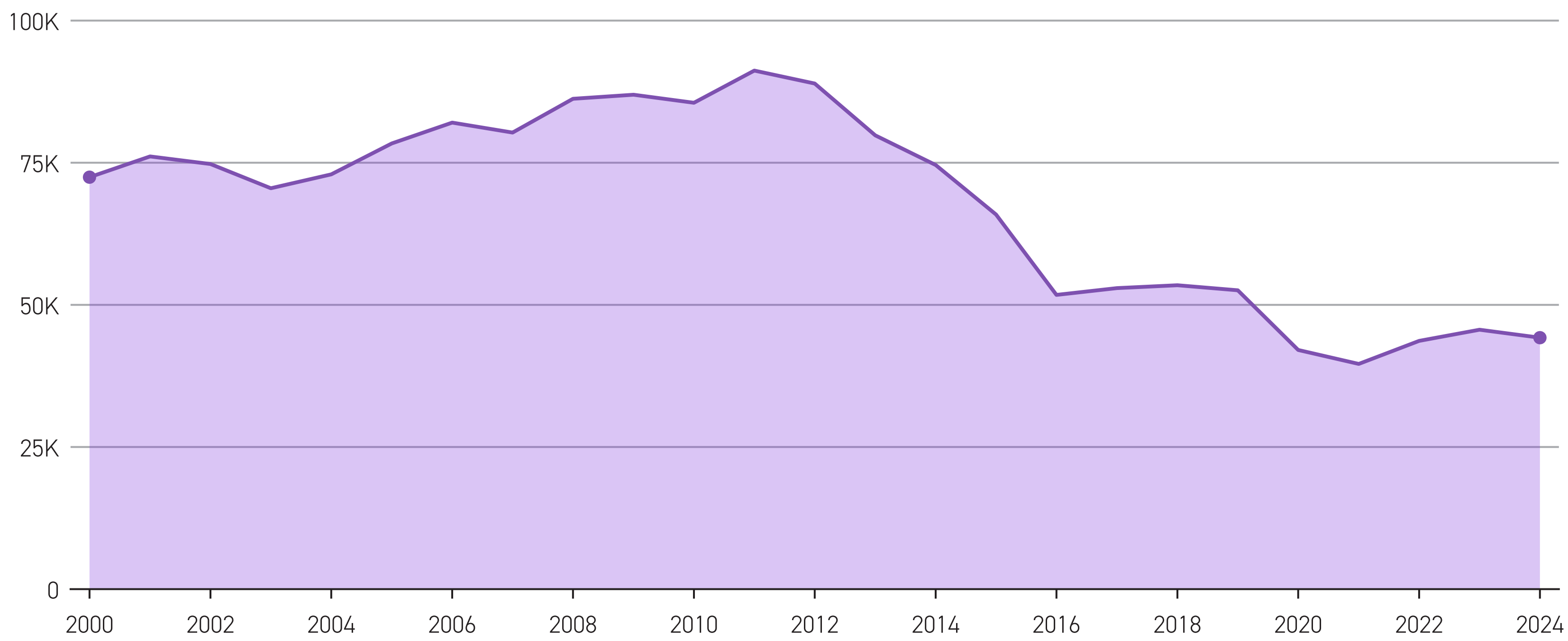
“All those plants that have been closed are going to be opened if they’re modern enough or they’ll be ripped down and brand new ones will be built,” said Trump. “We’re going to put the miners back to work.”

Also at the event was Buu Nygren, president of the Navajo Nation, who later praised the Trump administration (https://x.com/BuuVanNygren/status/1909740089795633344) for boosting Western coal mining. NTEC, the tribe’s wholly owned energy company and one of the largest coal producers in the U.S., is now moving forward with recently approved mining leases in Wyoming and Montana.

Conor Bernstein, a spokesperson for the National Mining Association, said coal’s fate has shifted quickly as onerous Biden-era regulations are pulled back and mining is boosted, providing more coal for producers and utilities.

The number of U.S. coal miners has dropped 39% from 2000

Number of U.S. coal miners



Source: U.S. Mine Safety & Health Administration
Claudine Hellmuth/POLITICO

Coal-fired generation buoyed by pressure from gas has now exceeded year-earlier levels each month during the first half of this year, said Bernstein. He also pointed to demand from artificial intelligence data centers growing, adding that grid operators are short on power and utilities are postponing and canceling coal plant retirements because they need dispatchable capacity.

“Global coal demand is also continuing to set records and U.S. energy exports are a central piece of the administration’s trade negotiations,” said Bernstein. “The stage is set for coal to play a deeply important — if unexpected — role in the U.S. electricity mix in the years ahead and meet a growing share of global coal demand.”

But Blumenfeld said the outlook is nuanced and the market continues to be strained. He noted that coal’s recent uptick was largely due to weather and coal competing with natural gas, which sank to less than $2 per million British thermal units (MMBtu) last year before climbing back up to around $3 per MMBtu today. That, in turn, increased demand for coal out of the Powder River Basin, he said.

Those gains could quickly dissipate if more coal plants come offline, he said. And coal still needs to compete with cheap natural gas after nuclear, hydropower and renewables, and it must do so in markets that continue to decline, said Blumenfeld.

Pierpont added that while growing power demand tied to manufacturing and AI could temporarily keep terminal coal plants online, coal still remains economically uncompetitive.

The cost of producing power from coal rose by 28 percent from 2021 through 2024, according to a report that Energy Innovation released (https://energyinnovation.org/report/coal-power-28-percent-more-expensive-in-2024-than-in-2021/) earlier this year. That uptick, the think tank said, was largely due to the rising cost of fuel for the plants, increased operations and maintenance costs, capital costs tied to maintaining aging plants that were not run and full capacity, and inflation.

"A lot of this data center demand growth is really fairly near term," said Pierpont. "If you look at the pipeline of projects that's going to be ready to deliver in the next three years, four years, it's by and large dominated by solar, energy storage, some wind and some natural gas.

"Most utilities … are really focused on … the most cost-effective resources to meet this growing demand," he added. "By and large, coal is not a part of that."

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EXHIBIT 69

Interior Approves Mining Plan to Unlock 14.5 Million Tons of Coal at Antelope Mine

Decision supports energy independence, extends mine operations through 2037

08/08/2025
Last edited 08/08/2025

Contact Information Interior_Press@ios.doi.gov

WASHINGTON — The Department of the Interior today announced approval of a mining plan modification that will unlock 14.5 million tons of federally owned coal at the Antelope Mine in Converse County, Wyoming. The Office of Surface Mining Reclamation and Enforcement issued the decision following completion of a rigorous environmental assessment and Finding of No Significant Impact.

The action approves the West Antelope II South Tract Mining Plan Modification associated with Federal Coal Lease WYW-177903 and authorizes coal production across approximately 857 federal acres. This critical decision extends the life of the mine — through 2037 — supporting continued production from one of the Powder River Basin's key energy contributors.

"The Trump administration is delivering on its promise to revitalize American coal and unleash our nation's energy potential," said **Secretary of the Interior Doug Burgum**. "This decision boosts American jobs, enhances energy security and supports communities that rely on coal to power their homes and economies."

Antelope Mine is operated by Navajo Transitional Energy Company and supports 359 full-time jobs. Located in both Converse and Campbell counties, the mine employs conventional surface-mining techniques and ships coal from an on-site rail facility to power plants and industrial customers across the country.

The mining plan modification ensures the continued availability of low-sulfur, low-ash, subbituminous coal from the Powder River Basin, a key region responsible for fueling a significant portion of America's coal-fired electricity. The decision aligns with President Trump's broader national energy strategy to reduce reliance on foreign sources, fortify grid reliability, and protect American jobs.

This decision supports the Trump administration's executive orders that aim to boost the clean coal industry in the U.S and promote energy independence. It also supports the recently passed One Big Beautiful Bill Act, which helps the coal industry by lowering royalty payments for mining coal on federal land and making more land available for coal mining.

"As global instability continues to threaten energy markets, the need for reliable, domestic coal has never been clearer," said **Acting Assistant Secretary for Land and Mineral Management Adam Suess**. "This action underscores our commitment to commonsense permitting, environmental stewardship and Energy Dominance."

In accordance with the National Environmental Policy Act and other federal environmental laws, OSMRE conducted a full environmental review of the proposed mining plan modification. The resulting Finding of No Significant Impact confirms that the project will not result in significant adverse environmental effects, paving the way for continued coal recovery under lawful, science-based oversight.

The Trump administration continues to take decisive action to reverse bureaucratic barriers, streamline federal permitting, and reinvest in and reinvigorate coal communities. Today's announcement builds on a series of recent actions aimed at restoring American energy leadership and delivering results for working American families. Earlier this month, the Department gave the green light for Hurricane Creek Mining, LLC to mine coal on Bryson Mountain in Claiborne County, Tennessee — a project expected to produce up to 1.8 million tons of coal over the next 10 years.

For more information about the mining plan modification, visit https://www.osmre.gov/programs/regulating-active-coal-mines/federal-lands.

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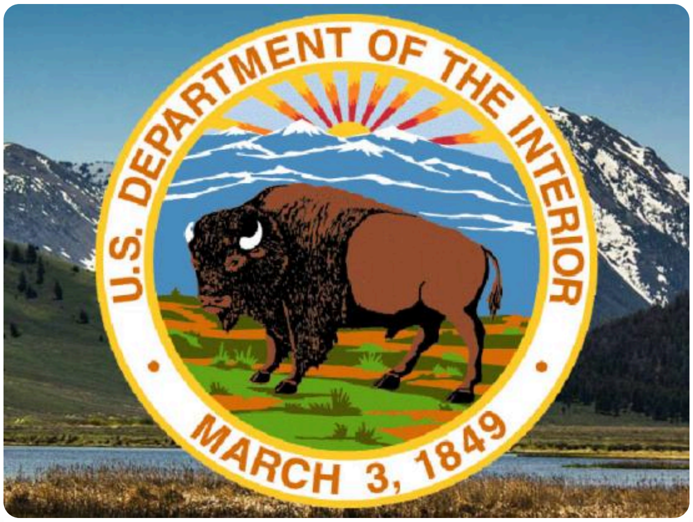
PRESS RELEASE



12/22/2025

The Trump Administration Protects U.S. National Security by Pausing Offshore Wind Leases

The Department of the Interior announced today that it is pausing — effective immediately — the leases for all large-scale offshore wind projects under construction in the United States due to national security risks identified by the Department of War in recently completed classified reports.

Read more

PRESS RELEASE

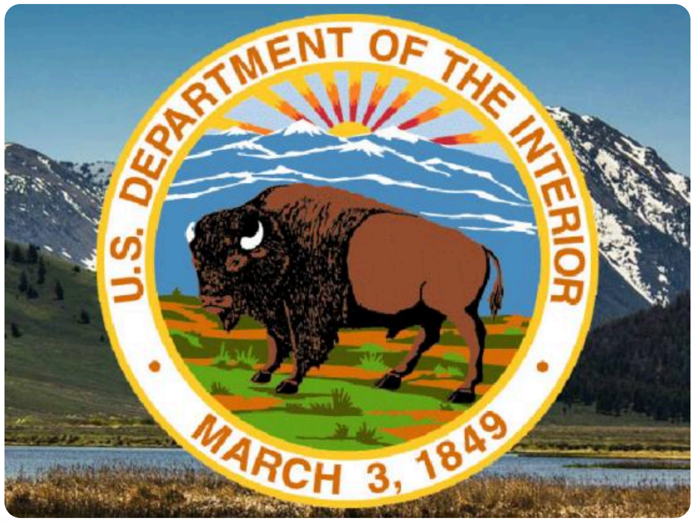
12/10/2025

Interior Advances American Offshore Energy Dominance with First Lease Sale Under the One Big...

The Department of the Interior today announced that the Bureau of Ocean Energy Management successfully conducted Lease Sale Big Beautiful Gulf 1, which is the first mandatory offshore oil and gas lease sale required under the One Big Beautiful Bill Act. The sale generated $279,433,757 in high bids for 181 blocks across 80 million acres in federal waters of the Gulf of America. Thirty companies submitted 219 bids totalling $371,881,093.

Read more

PRESS RELEASE



11/24/2025

Interior Announces $14.61 Billion in Fiscal Year 2025 Energy Revenue

Today, the Department of the Interior's Office of Natural Resources Revenue announced the disbursement of $14.61 billion in revenues generated in fiscal year 2025 from energy production on federal and tribal onshore lands, and federal offshore areas.

Read more

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EXHIBIT 70

The New York Times https://www.nytimes.com/interactive/2025/12/22/us/politics/trump-donors-fundraising-benefits.html

Hundreds of Big Post-Election Donors Have Benefited From Trump's Return to Office

The president's team has created a highly unusual fund-raising apparatus for causes he favors. The Times analyzed more than half a billion dollars in contributions from 346 donors. Some have received pardons, jobs, access to the president and other valuable gains.

By Karen Yourish, Kenneth P. Vogel and Charlie Smart Dec. 22, 2025

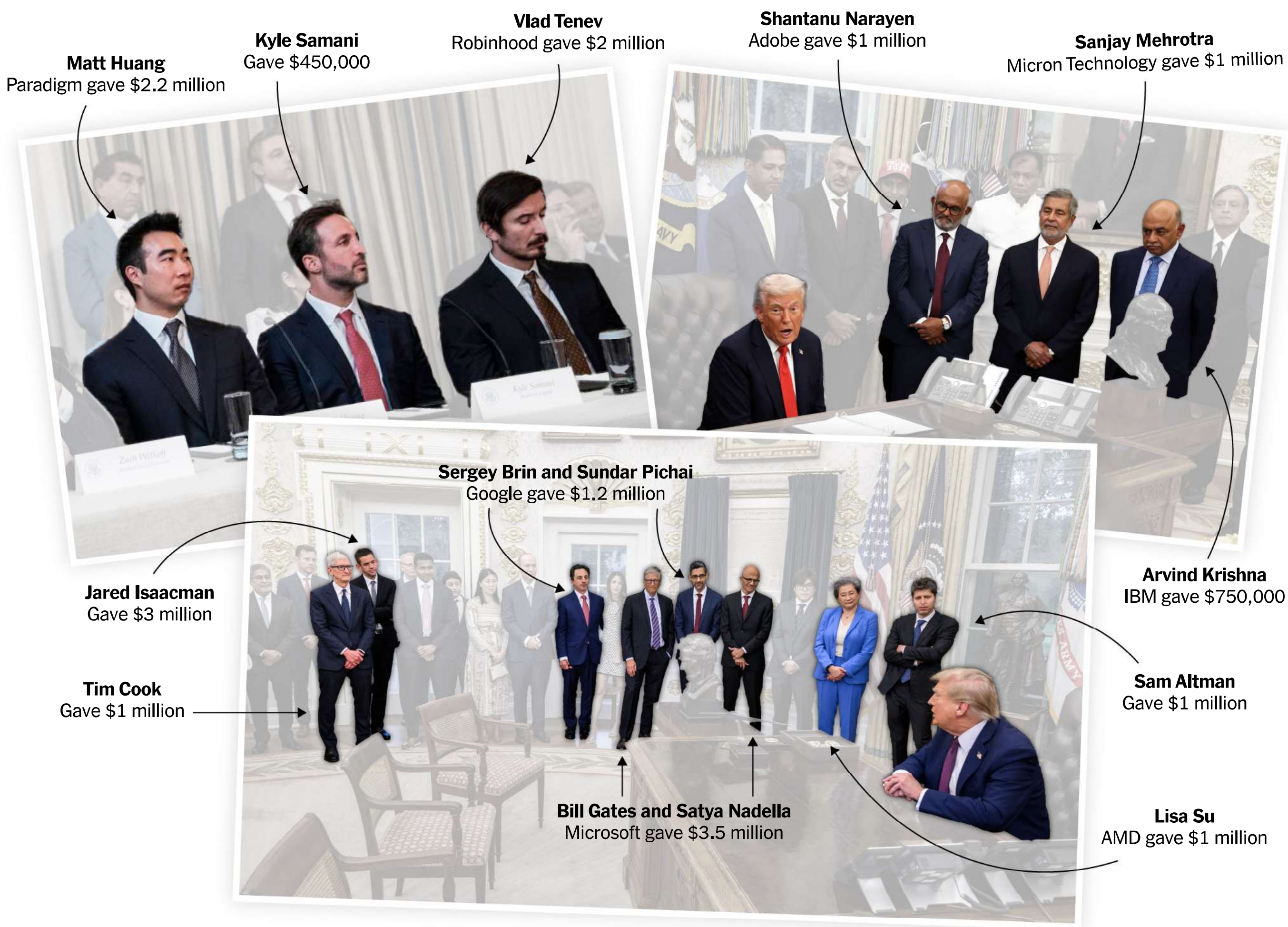


Illustration by the New York Times. Photos by Haiyun Jiang for The New York Times; Kevin Lamarque/Reuters; The White House

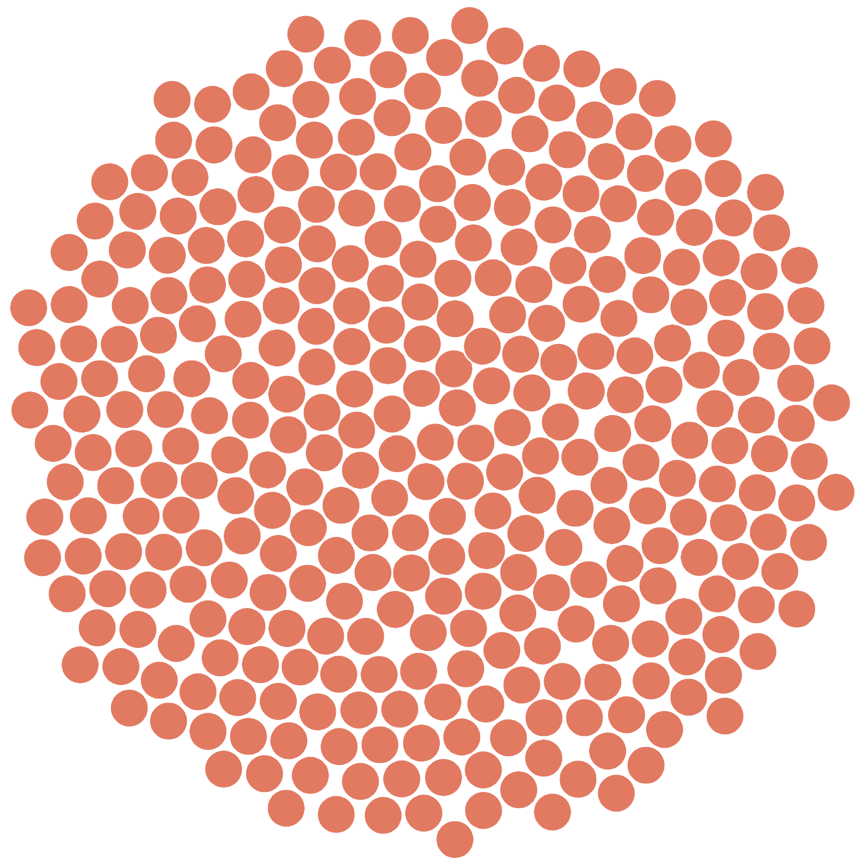
Since President Trump was elected a second time, he and his allies have raised nearly $2 billion for his favored political causes and passion projects. That total, which was confirmed by four people involved in the fund-raising, likely eclipses the amount raised to support his 2024 campaign.

The astounding haul hints at a level of transactionalism for which it is difficult to find obvious comparisons in modern American history. The identities of the donors behind much of the cash are not legally required to be, and have not been, publicly disclosed. In some cases, Mr. Trump's team has offered donors anonymity.

To shed light on what has been a largely opaque fund-raising apparatus, The New York Times conducted a comprehensive investigation. It relied on previously unreported documents and public campaign finance filings, as well as interviews with dozens of people who are familiar with the solicitations or are involved in the fund-raising. It traced a large portion of the funds raised — more than half a billion dollars' worth — back to 346 donors who each gave at least $250,000. It also found that more than half of them have benefited, or are involved in an industry that has benefited, from the actions or statements of Mr. Trump, the White House or federal agencies.

It is not possible to prove that any of the donations directly led to favorable treatment from the Trump administration. And the contributions do not personally enrich Mr. Trump, unlike some of his family's cryptocurrency ventures.

But many of the deep-pocketed individuals and corporations who have given large sums have a lot riding on the administration's actions, raising questions about conflicts of interest.



Each of these dots represents a person or company that has given at least $250,000 to a group or project supported by Mr. Trump since he was elected to a second term.

The president's **inaugural committee** raised nearly $240 million, more than double the record, which Mr. Trump himself set in 2017.

The 284 donors shown here each gave at least $250,000.

After Mr. Trump won, the fund-raising didn't stop for a super PAC devoted to him and run by his advisers. **At least 81 donors** gave $250,000 or more to **MAGA Inc.** It raised $200 million from Nov. 7, 2024, to June 30, 2025.

According to Mr. Trump, $350 million has been raised for his White House ballroom project, which is largely being processed by the **Trust for the National Mall**. The Times has identified pledged or completed donations from **14 ballroom donors,** which amount to about $100 million.

The biggest donors to the **White House Historical Association** to support this year's Easter Egg Roll, including the **four shown here**, were offered new types of branding opportunities and access to an event beforehand with Melania Trump, the first lady.

The president's team has also raised money for **America250**, a nonprofit group that was formed to produce celebrations for the country's semiquincentennial birthday. **Eight of the donors** identified by The Times sponsored this group after the 2024 election.

Of the 346 donors identified by The Times, **at least 197 have benefited, or are in industries that have benefited, from policies or actions** of Mr. Trump or his administration. Those include pardons, favorable regulatory moves, the dropping of legal cases, access to the president and more.

Hover or tap on each of the circles here to learn more about the individual and corporate donors who have given at least $250,000 to Trump-approved causes. (Dollar figures may be undercounts, since some kinds of donations do not need to be disclosed.)

Presidents of both parties have raised funds for their inaugurations, and many major companies have long histories of donating to them. But second-term presidents usually begin winding down their own fund-raising after their inaugurations, focusing instead on boosting their parties' committees and candidates.

Mr. Trump, on the other hand, was emboldened by the record-breaking sum of nearly $240 million raised by his inaugural committee. He immediately tasked his fund-raising team, led by his campaign's finance director, Meredith O'Rourke, to raise money for an array of groups and causes supported by the president, according to three people involved in the fund-raising. They requested anonymity to discuss nonpublic information, as did five others who discussed other elements of the fund-raising.

It is a buffet of options that allows donors to pay tribute to Mr. Trump and sometimes receive access to him to pitch their own interests. While the groups raising funds are independent from one another, and some are nonpartisan, they are presented to donors as part of a fund-raising apparatus to which Mr. Trump or his allies would like them to give, according to four people familiar with the fund-raising. They said Mr. Trump closely tracks which companies have given, and how much, debriefing regularly with Ms. O'Rourke.

Lobbyists with connections in Mr. Trump's orbit recommend that their clients donate to these groups to try to win him over, said five people familiar with the fund-raising.

"In this town, money talks, and that is going to give you an opportunity to at least have a seat at the table," said Harrison Fields, a former Trump White House official who left in August and became a lobbyist. His firm, CGCN Group, has represented companies that have donated to projects Mr. Trump supports, including the new White House ballroom, America250 and MAGA Inc.

"These people are not getting coerced. They are making business decisions," said Mr. Fields.

At least 51 of the donors have given to more than one of the groups in this analysis since the election.

While MAGA Inc., the inaugural committee and the Republican National Committee (another entity for which Trump-allied fund-raisers are soliciting money) are required to disclose their donors to the Federal Election Commission, there is no such requirement for contributions to other groups for which the president's allies are raising funds.

Those groups include the Trust for the National Mall, America250, the White House Historical Association, a political nonprofit group called Securing American Greatness and the John F. Kennedy Center for the Performing Arts, which Mr. Trump's allies have remade in his own image, including adding his own name to the title and the building's facade.

The Times's investigation identified a number of donations, or potential benefits to donors, that had not been publicly known.

One $2.5 million contribution to MAGA Inc. was given by a South Florida woman whose father months later received an unusually lenient deal from top Justice Department officials to settle charges that he bribed Puerto Rico's then-governor in 2020.

Another $2.5 million pledged donation — this one to Mr. Trump's White House ballroom project — came from Parsons Corporation, an engineering firm that has won government contracts for years, including under Mr. Trump, and is jockeying for some of the more than $1 trillion in contracts that could be awarded to build a missile defense system proposed by the president called the "Golden Dome." Also giving at least $2.5 million to the ballroom project was the chief executive of Roblox, a popular online video game company that has applauded a Trump executive order and other initiatives involving children's use of artificial intelligence.

A couple who donated $1 million to Mr. Trump's inaugural committee and $500,000 to MAGA Inc., as well as an undisclosed amount to the ballroom fund, saw Mr. Trump nominate their son to be U.S. ambassador to Finland.

And a company that was accused last year by the Justice Department of colluding over ticket prices donated $250,000 to Mr. Trump's inauguration. The president pardoned the company's co-founder in a separate case this month.

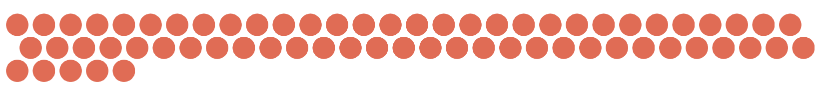
In other cases, The Times was able to quantify large donations for which the amounts were previously unknown. Those included gifts from the technology firm Palantir, which donated $10 million to the ballroom project and $5 million to America250. Additionally, the Palantir co-founder Alex Karp donated $1 million each to the inauguration and to MAGA Inc. In Mr. Trump's second term, Palantir has secured federal contracts worth hundreds of millions of dollars, including to develop software to help Immigration and Customs Enforcement deport people. But a Palantir official said in a previously unpublished response to an inquiry from Senator Richard Blumenthal, Democrat of Connecticut, that the company did not seek and was not offered any special consideration for its donation to the ballroom project.

While a foundation funded by Miriam Adelson, a casino magnate, mostly supports Jewish and Israeli causes, it pledged to donate $25 million to the ballroom project, according to two people familiar with the donation. In a speech at a White House Hanukkah party last week, Mr. Trump praised Dr. Adelson, a physician by training, for donating tens of millions of dollars to help his campaigns and using her access to lobby for greater U.S. backing for Israel. Calling her to the lectern, Mr. Trump said, "When somebody can give you $250 million, I think that we should give her the opportunity to say hello." The two embraced and bantered about how Dr. Adelson would be willing to donate $250 million more to help Mr. Trump seek an unconstitutional third term.

Mr. Trump's continued fund-raising is all the more striking given his boasts during his first presidential campaign a decade ago that he was an outsider whose personal wealth made him impervious to Washington's pay-to-play politics and the manipulation of major donors, including Dr. Adelson's late husband.

Liz Huston, a White House spokeswoman, rejected the suggestion that donors were getting special treatment. She said in a statement that Mr. Trump's "only motivation as the president of the United States is improving the lives of the American people and making our country greater than ever before." Donors who support him "should be celebrated, not attacked," she said.

Donors who received administration jobs, government contracts, partnerships and approvals



Hover to see donor details

While the donations far exceed most Americans' means, the sums pale in comparison to the contracts being sought from the Trump administration.

Take Mr. Trump's "Golden Dome" missile defense project, which could yield lucrative work for a number of contractors. Palantir has already held discussions about being involved. Firms including Lockheed Martin and Boeing also are expected to compete for pieces of the work; each company donated $1 million to Mr. Trump's inaugural committee. That is the same amount they gave to President Joseph R. Biden Jr.'s inaugural committee.

But Lockheed Martin also donated $10 million to the Trust for the National Mall for Mr. Trump's ballroom project and $5 million to America250, according to two people familiar with the sums.

Lockheed is the primary maker of F-35 fighter jets, which cost about $80 million to $110 million each. While some national security officials have expressed concern about selling the jets to Saudi Arabia, Mr. Trump announced last month that he planned to approve such sales. The next day, Lockheed's chief executive attended a black-tie dinner at the White House honoring Crown Prince Mohammed bin Salman of Saudi Arabia, which was also attended by executives for other defense contractors.

As for Boeing, two months after the inauguration, Mr. Trump announced that the company would be paid to build more than 180 new advanced fighter jets for the Air Force.

Major defense contracts can take years to develop, bid and execute, and there is no evidence that any such contracts were awarded as a direct result of donations.

Boeing's ability to pursue federal contracts could have been hindered by criminal charges stemming from two fatal crashes of its planes during Mr. Trump's first term. But this year, the Trump Justice Department dropped the case, entering into a settlement that required the company to improve its safety and compliance programs and pay hundreds of millions of dollars into a fund for victims.

Presidents have long awarded their campaigns' top donors with ambassadorships, jobs and appointments to boards and commissions. Mr. Trump appears to have taken that tradition to a new level, tapping at least 32 people for an array of positions — including in his cabinet — who have donated at least $250,000 each to his causes after the election, or whose companies or families have made such donations.

Among them is Howard Brodie, now the U.S. ambassador to Finland. His parents, Elizabeth and Stefan Brodie, donated to the Trump inauguration, MAGA Inc. and the ballroom project after Mr. Trump's victory in the 2024 election. The elder Brodies were invited to the White House dinner last month honoring the Saudi crown prince, and Stefan Brodie attended a dinner the month before for major donors who gave at least $2.5 million for the ballroom.

Another Trump ambassador nominee, the Miami mortgage lender Bernie Navarro, gave a little-noticed $1 million donation to the inaugural committee through an obscure company registered in Puerto Rico. Mr. Navarro, a close ally of Secretary of State Marco Rubio, said in a statement that the donation was unrelated to his interest in becoming an ambassador. "In retrospect, he is doing such an amazing job that I wish I would have done more," Mr. Navarro said of Mr. Trump.

In all, more than a dozen donors have been nominated or confirmed for ambassadorships.

Where donors received ambassadorships

Donor	Nominated or confirmed ambassador to…
Warren Stephens Gave $6 million	United Kingdom
Melissa Argyros Gave $2 million	Latvia
Dan Newlin Gave at least $1.5 million	Colombia
Howard Brodie Parents gave at least $1.5 million	Finland
Benjamin León Jr. Gave at least $1 million	Spain
Melinda Hildebrand Gave combined $1 million together with her husband	Costa Rica
Ken Howery Gave $1 million	Denmark
Tilman Fertitta Gave $1 million	Italy
Bernie Navarro Gave $1 million	Peru
Anjani Sinha Gave $1 million	Singapore
Peter Lamelas Gave $250,000	Argentina
Nicole McGraw Gave $250,000	Croatia
John Breslow Gave $250,000	Cyprus
Benjamin Landa Gave $250,000	Hungary
Joseph Victor Popolo Jr. Gave $250,000	Netherlands

It is not possible to definitively link donations to nominations.

Tommy Pigott, a spokesman for the State Department, in a statement called Mr. Trump's ambassadors "an America first diplomatic A-team," adding that they "were chosen to help drive forward historic wins for the American people, and they have done exactly that."

Four of Mr. Trump's cabinet officials made personal or corporate donations of more than $250,000.

They include Kelly Loeffler, the administrator of the Small Business Administration. She and her husband, Jeffrey C. Sprecher, the chief executive of the parent company of the New York Stock Exchange, donated a combined total of $11 million to groups Mr. Trump favors, including $1 million to the inaugural committee and $5 million to MAGA Inc., as well as previously unreported donations totaling $5 million for the ballroom, according to records and a person familiar with the fund-raising.

Donors who received pardons, relaxed enforcement and other relief

Hover to see donor details

Getting a reprieve from adverse state action can be just as valuable as winning a government contract or appointment.

Extremity Care, a company that makes a pricey form of bandages known as skin substitutes, donated $5 million to MAGA Inc. An executive from the company then attended a donor dinner in March at Mar-a-Lago where he lobbied Mr. Trump, whose administration announced the next month that it would delay a Biden-era plan to limit Medicare's coverage of the bandages. Extremity Care or one of its affiliates subsequently donated $2.5 million to the ballroom.

And Mr. Trump has entered into deals with a number of drug makers, including several that donated to groups he supports, to lower prices in exchange for avoiding punitive measures including threatened tariffs.

In two instances, Mr. Trump pardoned people whose companies or families made donations.

In January, amid scrutiny from the Justice Department's antitrust division, which had identified — but not charged — the venue management company Oak View Group in a lawsuit against Ticketmaster's parent company, Oak View donated $250,000 to Mr. Trump's inauguration.

The donation did not eliminate legal exposure for Oak View's co-founder and then-chief executive, Timothy J. Leiweke. Months later, the antitrust division charged him in an unrelated case. He stepped down as head of Oak View, and the company agreed to pay $15 million in penalties. Mr. Leiweke pleaded not guilty. But this month, before the case went to trial, Mr. Trump pardoned him.

David B. Gerger, a lawyer for Mr. Leiweke, rejected a question about whether the donation was intended to avoid legal trouble.

"Any such innuendo — whether coming from ill will or just ignorance — is false," he said in a statement.

In another case, the former health care entrepreneur Elizabeth Fago, after donating $1 million to MAGA Inc., attended a donor dinner with the president. Mr. Trump pardoned her son, Paul Walczak, less than three weeks later, sparing him from having to pay nearly $4.4 million in restitution and from reporting to prison for an 18-month sentence for employment tax crimes.

Another donor with an interest in the outcome of a criminal case was Isabela Herrera, who donated $2.5 million to MAGA Inc. late last year. At the time, her father, Julio Herrera Velutini, a Venezuelan-Italian banker, was being prosecuted by the Justice Department for trying to bribe the governor of Puerto Rico.

Mr. Herrera hired a former personal lawyer for Mr. Trump, who alleged that the case was an example of the political weaponization of the criminal justice system. Top Justice Department officials appeared to agree, authorizing a misdemeanor plea deal to settle the case and overruling career prosecutors who had pushed for a harsher sentence.

Mr. Herrera could still face a year in prison at sentencing, which is scheduled for next month.

Ms. Herrera and a lawyer for Mr. Herrera declined to comment.

A Justice Department spokeswoman said "the decision to settle this case was made through the proper channels and was not influenced by any donation to MAGA Inc."

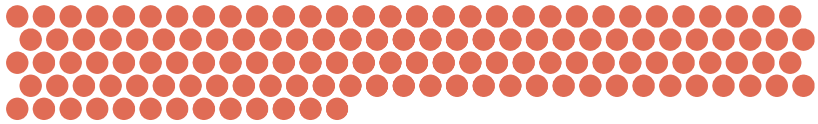
But John D. Keller, who oversaw the Justice Department division that handled the case, said in an interview that the difference between the deal and the more than 20 years Mr. Herrera could have faced if convicted of the original charges was "striking." Mr. Keller, who resigned in protest when he was directed by Mr. Trump's appointees to drop another politically fraught prosecution, said the Herrera case "appears to be another example of political considerations dictating the outcome in an individual criminal case."

A broader relaxation of federal scrutiny has benefited cryptocurrency companies and other corporate interests that have showered donations on Mr. Trump's groups.

The Securities and Exchange Commission largely abandoned its hard-line approach to crypto trading platforms, ending lawsuits against Coinbase, Kraken and Ripple after the companies each donated $1 million or more to Mr. Trump's inaugural committee, and ending an investigation into Robinhood after it donated $2 million to the committee. Coinbase and Ripple also donated to the ballroom, while Coinbase gave to America250.

A spokesman for the S.E.C. said that "politics have had nothing to do with S.E.C. actions" on the cases. "Decisions on these cases turn on long held publicly expressed legal and policy views," he added.

Donors in industries that benefited from administration policies



Hover to see donor details

In addition to specific benefits enjoyed by individual companies and people, Mr. Trump has also enacted sweeping tax cuts and taken other actions that more broadly advantage a wide range of industries, major corporations and wealthy individuals.

Last week, Mr. Trump signed an executive order to downgrade cannabis from the most restrictive category of drugs, easing some limitations and allowing for more research. It was a major victory for a burgeoning industry that has spent heavily since the election on lobbying and donations, including a $1 million donation to MAGA Inc. from American Rights and Reform PAC, a pro-cannabis political committee; and a $750,000 donation to the inaugural committee from Trulieve, a leading marijuana retailer. Kim Rivers, Trulieve's co-founder and chief executive, urged Mr. Trump to make the move during multiple meetings with him, including a donor dinner at his New Jersey golf club in August, according to a person familiar with the event, which was first reported by the Wall Street Journal.

"We are really thankful for the president," Ms. Rivers said in an interview on Thursday. "He has been consistently supportive," she added. She declined to comment when asked if she would have been granted the presidential audiences without donating.

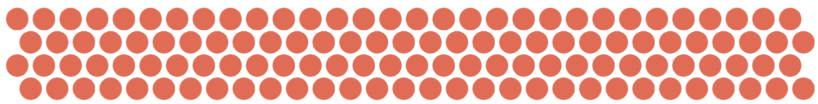
The crypto industry writ large has benefited from Mr. Trump's cheerleading, as well as his championing and signing into law a bill creating the first federal rules for stablecoins, a popular form of digital currency. At least 27 companies or executives with interests in crypto gave a total of at least $58 million to groups Mr. Trump favors after the election, The Times found.

Mr. Trump has also favored the fossil fuel industry, directing tens of billions of dollars in incentives to companies, allowing drilling in the Alaska wilderness, and repealing environmental regulations. About two dozen companies with interests in oil, gas and coal donated at least $41 million.

Likewise, the administration has pushed regulatory changes and other executive actions that benefit Big Tech, tobacco interests, private equity firms and the defense and aerospace industry. (In all of the industries discussed here, individuals and firms may have benefited to different degrees from these actions.)

Danielle Alvarez, a spokeswoman for the R.N.C., said Mr. Trump "has governed and delivered results for every American," citing his efforts to secure the Southern border and crack down on fentanyl trafficking, among other initiatives. She said Mr. Trump "is grateful to his donors, but unlike the politicians of the past, he isn't bought by anyone."

Donors who received invitations, access and praise



Hover to see donor details

Since retaking office, the president has lavished his post-election donors with praise and access to himself and his inner circle. In some cases, the attention can provide a competitive business advantage. In others, it may only mean bragging rights.

At least 100 donors have attended exclusive dinners and events with Mr. Trump at the White House, accompanied him on overseas trips that include meetings with foreign dignitaries and prospective business partners — or both. About half have popped up at multiple events. Regular visitors to 1600 Pennsylvania Avenue include Jensen Huang, chief executive of Nvidia; Lisa Su, chief executive of AMD; Tim Cook, chief executive of Apple; and others.

Mr. Trump is fond of using these presidential forums to call out friends and donors in the room.

"So many of you have been really, really generous," Mr. Trump told donors to the ballroom project he convened at the White House for a thank-you dinner in October. He singled out defense contractor donors (representatives for Booz Allen Hamilton, Lockheed Martin and Palantir were in the room), saying the United States was "the greatest manufacturer of weapons."

And it's not just Mr. Trump.

The White House has used government platforms to praise major donors to a wider audience. At least 67 post-election donors have been positively featured, often multiple times, in official press releases, social media posts and other communications.

The New York Times

There is a flip side to Mr. Trump's willingness to reward loyalty. His efforts to punish perpetrators of perceived slights have been an animating theme of his second term — and a motivating factor for at least some of the donors to his favored causes, according to three people familiar with the fund-raising.

They said that major donors and corporations fear incurring Mr. Trump's wrath by not giving, or not giving as much as their rivals, and that they donate out of concern that he might publicly attack them or even use the levers of government against them. Donations, they said, serve as a form of protection — or, if things have already soured, as an olive branch.

But it's no guarantee. For some companies that have given large sums since the election, Mr. Trump and his administration's actions have not been exclusively helpful.

Pilgrim's Pride, a massive poultry producer, donated $5 million to Mr. Trump's inaugural committee, making it the biggest donor. Good news for the poultry industry followed: In April, the Trump administration withdrew a Biden-era proposal that would have required poultry companies to keep levels of salmonella bacteria under a certain threshold and to test for six dangerous salmonella strains.

And in June, after years of attempts, federal regulators approved a public listing on the New York Stock Exchange for JBS, the Brazilian firm that owns Pilgrim's Pride. But then last month, Mr. Trump directed the Justice Department to investigate JBS and three other meat packing giants, accusing them of "driving up the price of beef through illicit collusion, price fixing and price manipulation."

In another example, Mr. Trump's relationship with Mark Zuckerberg has been a mixed bag over the years. But when Mr. Trump won last fall, Mr. Zuckerberg and Meta, the parent company of Facebook, Instagram and other platforms, took steps that seemed designed to appease the incoming president. Meta donated $1 million to his inauguration, as did other tech companies and executives that had occasionally been crosswise with Mr. Trump, including Amazon, Google and Apple's chief executive, Mr. Cook. The companies' executives were given prominent places behind Mr. Trump inside the Capitol rotunda as he was sworn in.

Days after the inauguration, Meta announced that it had agreed to pay $22 million to Mr. Trump's library foundation to settle a lawsuit. Google agreed to donate a similar sum for the ballroom project to settle a similar suit. (Those settlement amounts are not included in the analysis presented in this article, nor are payments to the Trump library foundation by Paramount Global and ABC News to settle separate lawsuits brought by Mr. Trump.) Meta also donated at least $2.5 million for the ballroom project, according to a person familiar with the fund-raising.

And Amazon, Meta and Google each donated at least $200,000 to the White House Historical Association to sponsor the annual Easter Egg Roll. While Meta and Google had sponsored the event during the Biden administration, top sponsors have not traditionally been expressly offered access to a pre-event brunch with the first lady as a donor perk, according to a person familiar with the event.

The offer came from a private event production firm on contract with the association, and not the association itself, which does not offer access to the White House or first family as an inducement for donations, according to a person familiar with previous fund-raising efforts.

Mr. Zuckerberg unsuccessfully lobbied Mr. Trump and his aides to derail a federal antitrust lawsuit against Meta. (A judge dismissed the case on its merits last month.) But the company has won other victories from the administration. The Consumer Financial Protection Bureau ended an investigation into Meta's advertising for financial products in September, amidst a Trump-led push to kill the agency. And Mr. Trump this month signed an executive order to neuter state laws that limit the artificial intelligence industry — a major growth area for Meta, Google and other tech companies.

(The New York Times has sued three tech companies that are among, or whose executives are among, the donors in this analysis — Microsoft, OpenAI and Perplexity — claiming copyright infringement of news content related to A.I. systems. The companies have denied the suits' claims.)

As Mr. Trump's term moves into its second year, there are signs that the president and his allies intend to continue the fund-raising push.

MAGA Inc. has already announced dinners for donors who give $1 million or more, with Mr. Trump at his golf club in the Virginia suburbs of Washington in January and at his Mar-a-Lago club in Palm Beach, Fla., in February, according to invitations reviewed by The Times.

And the Donald J. Trump Presidential Library Foundation has indicated in filings that it intends to raise $950 million before the beginning of Mr. Trump's final year in office.

If anything, the buffet of options to which donors can give appears to be expanding.

Last week, Mr. Trump announced the creation of a new initiative called Freedom 250, which will raise money from corporations and donors to fund events and projects dear to him as part of the celebration of the 250th anniversary of the country's independence. Those include an arch overlooking Washington in the style of the Arc de Triomphe in Paris, a National Garden of American Heroes, a prayer event on the National Mall and a four-day competition for high school athletes.

Freedom 250 will be housed inside the National Park Foundation, a nonpartisan nonprofit group. Last month, at the behest of the Trump administration, the foundation quietly added to its board Ms. O'Rourke, who will raise money for Freedom 250, and Chris LaCivita, who helped run Mr. Trump's 2024 presidential campaign.

Ms. O'Rourke did not respond to a request for comment. Mr. LaCivita declined to comment.

Methodology

The Times created a database of every person, company and organization that Federal Election Commission filings indicated had donated at least $250,000 to the inaugural committee or MAGA Inc. after the 2024 election. After establishing this initial universe, The Times, through interviews and other reporting, expanded the database to include donors to Trump-supported groups and projects that — unlike the inaugural committee and MAGA Inc. — are not required to disclose their donors, including the White House ballroom project, the White House Easter Egg Roll and America250.

Reporters combed through documents and interviewed dozens of people to determine the donors behind each contribution (some of their identities were obscured in public filings by corporate structures), as well whether and how each donor may have benefited from actions by Mr. Trump or his administration. This involved reviewing lobbying disclosures; campaign finance and corporate filings; Securities and Exchange Commission reports; agency memos; government contracting databases; corporate and government press releases; White House pool reports; social media posts; transcripts, photographs and video from White House events; and other documents. The Times reached out to everyone identified as having benefited from actions by Mr. Trump or his administration. Some people and companies did not respond or declined to comment. Others said they did not benefit from the administration's actions. And others did not dispute the characterization.

In some cases, companies had existing contractor relationships with the federal government; this analysis included new contracts and renewals only, not those awarded in previous administrations.

Sarah Bahr, Kitty Bennett, Sarah Cahalan, Amanda Newman, Destinée-Charisse Royal and Hannah Wulkan contributed reporting.

Correction: Dec. 22, 2025
An earlier version of a video in this article showed an incorrect donation amount for Palantir. Palantir donated $15 million, not $20 million.

EXHIBIT 71

Democracy Dies in Darkness

White House offers ‘concierge’ service to fossil fuel firms, official says

Brittany Kelm, a senior policy adviser for the National Energy Dominance Council, detailed in a podcast how the council works to advance fossil fuel projects.

Updated October 7, 2025

By Jake Spring

The White House is offering “concierge, white glove servic
that are seeking to gain fast approval for their projects, acc
simultaneously slowing down or blocking solar and wind p

Brittany Kelm, senior policy adviser for President Donald T
Council, detailed in an August podcast how she and the cou
Trump established the committee in February with Interio

“We’re like this little tiger team, concierge, white glove service, essentially,” Kelm said. “We were put together very particularly with the president’s priorities in mind on energy. So keeping coal plants open, establishing critical mineral mining domestically and then that broader supply chain.”

Kelm did not immediately respond to a request for comment.

White House spokesperson Kush Desai said that the administration is Joe Biden's preferential treatment for green energy projects and "war" on

"The American people gave President Trump a resounding mandate to eash the power of American energy, and the Administration is committed to aid in a written statement.

National Energy Dominance Council Executive Director Jarrod Agen s e council supports increasing "base load power generation."

"Reliable sources like oil and gas, along with critical minerals, are esse n power to not only win the AI arms race but also sell energy to our allies so th r adversaries," Agen said.

Trump wants to boost production of oil, gas, coal and critical minerals of favoring fossil fuels to address his self-declared national energy emergency. Dive deeper

At the same time, his administration has held up permits for solar and wind projects since July and blocked wind farms outright. The Energy Department last week canceled $7.6 billion in funding for projects aimed at curbing climate change including installation of renewables, grid upgrades and carbon capture projects. That's on top of $27 billion in funding for clean energy that the Environmental Protection Agency is seeking to claw back.

“Fossil fuels and renewable energy face two very different permitting realities in this country,” said Ted Kelly, director and lead counsel for clean energy at the Environmental Defense Fund, an advocacy group, regarding Kelm’s comments. “For coal, oil and gas, it’s white glove service. For renewables and storage, it’s freezes, delays and cancellations.”

This is a normal way for the White House to operate, said Diana Furchtgott-Roth, director of the Center for Energy, Climate, and Environment at the Heritage Foundation, a conservative think tank. Companies consult with Trump’s energy council just as a financial firm might consult with the White House’s long-standing National Economic Council or a health care company with the Domestic Policy Council, she said.

“Elections have consequences. President Trump ran on a platform of increasing the use of oil, gas and natural resources,” Furchtgott-Roth said. “I see nothing nefarious in President Trump fulfilling his campaign promises through the National Energy Dominance Council. In fact, it would be odd if he didn’t.”

Kelm, who previously worked for oil companies including S
would connect a company looking to advance a pipeline wi
permits. "They can walk out of our office, and they have all

Kelm said her team then follows up on the project to get a
certain agency or stage of the process, working with the Int
Environmental Protection Agency and other government a

"We know how to unstick what is stuck," Kelm said. "It's a
regulatory burdens."

Kelm gave an example of an unnamed company getting approval in four days for what previously would take 45 days. She also described working with various departments on the proposal to open the National Petroleum Reserve in Alaska to development.

Trump issued a memo on Monday instructing federal agencies to issue any approvals necessary for a 211-mile road through Alaskan wilderness to be built to enable mining of copper and zinc deposits. The White House took a 10 percent stake in Trilogy Metals, a partner in Ambler Metals, which is seeking to develop a mine accessible from the proposed roadway.

The administration is also in the process of auctioning off the rights to mine for coal in Alabama, Montana, Utah and Wyoming, following on earlier efforts to expand existing coal mining leases and orders to prolong the life of coal power plants.

"This two-tiered approach — going to great lengths to prop up costly fossil fuels like coal plants while blocking the cheapest, cleanest energy sources — won't lower electricity costs," Kelly, of the Environmental Defense Fund, said in a statement. "It just saddles families and businesses with higher bills and more asthma-causing pollution."