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March 17, 2023

Via PUCN Filing System

Ms. Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 E. William Street
Carson City, Nevada 89701

Re: Docket No,. 22-11-032 – Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Fourth Amendment to its 2021 Joint Integrated Resource Plan

Dear Ms. Osborne:

Enclosed please find the Direct Testimony of Mark D. Detsky, Esq. on behalf of Interwest Energy Alliance in the above-referenced docket. Please let me know if you have any questions or concerns.

Sincerely,

/s/ Lina Tanner

Lina Tanner, Esq.

Enc.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company	)	
d/b/a NV Energy and Sierra Pacific Power Company	)	Docket No. 22-11032
d/b/a NV Energy for approval of their Fourth Amendment	)	
to the 2021 Joint Integrated Resource Plan.	)	

Direct Testimony of

Mark D. Detsky, Esq.

on behalf of

Interwest Energy Alliance

March 17, 2023

I. Introduction and Purpose

1. Q. State your name, position, and business address.

A. My name is Mark Detsky. I am an attorney and partner at Dietze and Davis, P.C. My address is 2060 Broadway, Suite 400, Boulder, Colorado 80302.

2. Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Interwest Energy Alliance (Interwest).

3. Q. Please introduce Interwest and its role in this proceeding.

A. Interwest is a 20-year-old organization comprised of utility-scale renewable energy, storage, and transmission developers and manufacturers that, working together with leading non-governmental environmental organizations,] promote the growth of renewable energy and energy storage markets throughout the Intermountain West. Interwest is a 501(c)(6) nonprofit trade association and is not a market participant; it is neither a bidder nor a developer of generation projects. Interwest has been an active stakeholder for many years in Nevada, but also in the Arizona, Colorado, New Mexico, Utah, and Wyoming regulatory proceedings related to integrated generation and transmission resource planning, transmission planning, and related activities.

4. Q. Please summarize your qualifications and work experience.

A. My resume is included as **Exhibit MDD-1.** I have more than eighteen years of experience representing clients in resource planning proceedings of regulated utilities, including five of the Integrated Resource Plans (IRP) of Public Service Company of Colorado (PSCo). I have also participated in drafting and editing legislation, rulemakings, certificates of convenience and necessity (CPCNs), and other Commission proceedings related to resource planning. I have been endorsed as an expert in resource planning proceedings in the Georgia Power IRP in 2019 and in the Alabama Power IRP in 2020.

My primary perspective comes from Colorado, where my legal practice includes the representation of Independent Power Producers (IPPs), including an IPP trade association. I am not an engineer or a modeler, so while I have experience with electric system modeling that informs my policy testimony, I do not testify as technical expert. In addition to resource planning, I have substantial experience in transmission, IPP project development, and mergers and acquisitions. My experience totals over 20 IRPs, transmission, and alternative resource acquisition proceedings for utilities of different sizes, in regions that are not part of a Regional Transmission Organization (RTO). In 2020, I co-authored a report analyzing best practices in resource planning.[1]

5. Q. Have you testified before the Public Utilities Commission of Nevada?

A. No, this is my first time testifying before the Public Utilities Commission of Nevada (Commission), and I appreciate the opportunity.

6. Q. What is the purpose of your testimony?

A. My testimony demonstrates that the resource planning processes of Sierra Pacific Power Company d/b/a NV Energy (SPPC) and Nevada Power Company d/b/a NV Energy (NPC) (collectively NV Energy or the Company) could be improved to reflect IRP best practices, and in turn benefit both the Nevada generation market and Nevada ratepayers. To provide

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[1] See Exhibit MDD-2, Detsky, M., Lehr, R., Wilson, J, and O'Boyle, M., *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,* Energy Innovation and the Southern Alliance for Clean Energy (April 2020), available at https://cleanenergy.org/wp-content/uploads/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices_EI_SACE.pdf

increased ratepayer benefits, the 2024 IRP process should improve certainty and transparency for the IPP generation market in two ways.

First, I recommend that the Commission consider limiting the next IRP to two principal phases, with the first phase reviewing base case scenarios as proposed in the IRP and an improved resource procurement process in a second phase Rather than approving resource acquisitions based on a utility's "base case," the Phase 1 decision would set the stage for an all-source Request for Proposals (RFP) that becomes the subject of the Commission's review in the second phase. Of course, this process would not foreclose amendments or even other phases if circumstances warrant. However, a two-phase process that scrutinizes resource needs, key modeling assumptions and bid evaluation metrics, and then approves resource acquisitions through an all-source RFP process will enhance competition and provide value to the Commission and electricity consumers. This approach has been shown to lower power prices and increase the bid pool in other regions. Improving NV Energy's bid pool is particularly important given the relatively low numbers of alternatives revealed by NV Energy's RFPs.

Second, I recommend that the Commission find that an all-source RFP approach to resource acquisition is in the public interest to fulfill NV Energy's resource needs in an IRP. For each future IRP, I recommend the Commission in Phase 1 approve the parameters of an all-source RFP for capacity and energy prior to approving new generation acquisitions. By setting forth concrete all-source RFP requirements in advance, the Commission can ensure a predictable bidding environment and dissuade either utility-owned generation (UOG) or power purchase agreement projects (PPAs) proposals made on an *ad hoc* or stand-alone basis without transparent comparison to market alternatives.

To that end, the Commission should consider the benefits of introducing a new IRP procedure comprised of approving resource portfolios in Phase 1 and then evaluating resources to implement those portfolios in Phase 2, based on the bids received, together with estimated transmission costs. This portfolio approach will increase cost certainty and transparency for Nevada utility customers. This does not mean that the utility cannot present reasonable ownership requests either as utility sponsored proposals, benchmark bids, or build-transfer bids, or respond to extenuating circumstances like the 2021 – 2022 period has represented for solar energy. Rather, it represents a more efficient IRP framework to guide and optimize utility resource selection in the first instance.

NV Energy's requests presented in the Fourth Amendment rely on "base case" modeling for resource acquisitions, a practice that disregards the five RFPs that it has issued since 2020. This means that the Company's system modeling and bid evaluation approach is beyond the reach of the Commission to evaluate prior to resource acquisition. It also means that NV Energy's capacity expansion model is not leveraged to the full extent of its functionality. As a result, it is an uphill climb for parties to question key assumptions that have an outsized effect on the resources acquired. Because NV Energy has already moved forward with its preferred gas-fired combustion turbine (CT) acquisition and executed PPAs, the Commission is limited to an after-the-fact review.

7. Q. How is your testimony organized?

A. My testimony is limited to the topic of acquisitions of utility-scale supply side resources. I discuss IRP process best practices, by which I mean best practices to manage cost and risk for NV Energy customers based on the competitive generation market. I then show how the Company's IRP and RFP approaches did not conform to best practices and have potentially led to more expensive projects and more risk for its customers. Third, I explain how the Commission can take steps to increase competition in the next IRP.

8. Q. Are you submitting exhibits along with your testimony?

A. Yes, I am submitting 16 exhibits along with my testimony as shown in the table below.

MDD - 1	CV
MDD - 2	2020 Energy Innovation *et. al*. paper*: "Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement."*
MDD - 3	RMI 2023 paper: "Reimagining Resource Planning"
MDD - 4	Colorado IRP process visualization
MDD – 5	Xcel Energy Colorado, *2016 Electric Resource Plan, Public Refile of 120-Day Report*, CPUC Proceeding No. 16A-0396E (June 6, 2018), with attachment 4 appended.
MDD – 6	IEA 2-09
MDD – 7	IEA 2-10
MDD – 8	IEA 2-01
MDD – 9	IEA 2-04(f) 2023 NV Energy RFP
MDD – 10	IEA 2-05
MDD – 11	IEA 2-03 with attachment 2022 NV Energy Spring RFP
MDD – 12	IEA 3-08
MDD – 13	IEA 3-07
MDD – 14	Interwest 3-02 – 2023 RFP Questions and Answers
MDD – 15	Interwest 3-02 - 2022 Spring RE RFP Bids Received
MDD – 16	IEA 3-04

II. Summary of Recommendations

9. Q. Please summarize your recommendations.

A. I recommend that the Commission order as follows:

a. Create a two-phase process in next IRP with Commission decisions at the conclusion of each phase as follows:

   i. Phase I – approve a resource adequacy constraint, approve modeling assumptions including policy constraints and bid evaluation parameters of an all-source RFP, including approving scenarios to meet policy goals including utility ownership targets or acquisitions, and approve bid portfolios to be examined in Phase 2. If UOG projects are presented in Phase 1, those should be tested against the all-source RFP in Phase 2.

   ii. Phase 2 – Within a certain timeframe following NV Energy's receipt of bids, require NV Energy to present a Phase 2 Report populating bid portfolios approved in Phase 1 with resources for Commission review and approval. Approve a resource portfolio to be acquired based on the results of the all-source RFP.

b. Require additional phases if updates or amendments are required, otherwise require annual reporting updates ahead of the next IRP. Additional phases should follow a truncated Phase 1 and 2 process.

c. Incorporate an all-source RFP prior to resource acquisition approval:

i. In an all-source RFP, the "base case" is an informational exercise that begins a discussion on modeling parameters for bid evaluation by which all types of technologies compete to provide capacity and energy to the system.

ii. Provide clear direction to the IPP market on the resource need, bid evaluation, and acquisition approval process in the RFP.

iii. Use the capacity expansion and production cost models to create optimized resource portfolios as outlined in Phase I. Require the utility to present to the Commission a preferred portfolio. Ideally, support a process through which portfolios are crafted and refined with stakeholder input prior to the IRP filing.

III. Statutory Framework

10. Q. Do Nevada statutes have timeline constraints for filing of IRPs and procurement requirements?

A. I am an attorney, although I am not licensed to practice in Nevada. However, my education, experience, and specific utility regulatory practice in other jurisdictions allows me to opine on the plain language of Nevada's utility statutes and regulations, as well as the implication of similar laws in other jurisdictions. To that end, Nevada has enacted several requirements through statute and regulation that set forth the timelines for the filing of IRPs and the issuance of Commission decisions.

Under Nevada Revised Statute (NRS) 704.741, NPC and SPPC, being affiliated through the common ownership of NV Energy, must submit a joint application for approval of an IRP plan every third year. NV Energy filed the joint application in Docket No. 21-06001 on June 1, 2021 pursuant to this statutory timeline. Under Nevada Administrative Code (NAC) 704.9482, the Energy Supply Plan (ESP) is to include the development of "a purchased power procurement plan." The purchased power procurement plan of a utility must include, without limitation:

> (a) The proposed mix of purchased power products by:
> (1) Type of resource;
> (2) Delivery profile; and
> (3) The term that the utility considers appropriate for the expected demand.
> (b) A description of the criteria used to determine the proposed mix of power products and the material factors influencing the selection of the criteria.
> (c) The proposed schedule for procuring the purchased power products, including a description of any competitive procurement processes to be undertaken.
> (d) A regional assessment of the availability of fuel and purchased power resources for the period covered by [2]the energy supply plan.
> (e) A projection of remaining capacity and energy requirements for each year of the period covered by the energy supply plan, after accounting for all existing resources and proposed long-term purchased power obligations.
> (f) A description, by type and term, of each existing purchased power contract with deliveries during the period covered by the energy supply plan.
> (g) A description, by type, delivery profile and term, of the purchased power products expected to be available to the utility during the period covered by the energy supply plan.

Procurement plans must further employ "risk management strategies" and "the criteria used to evaluate the effectiveness of the risk management strategy," per NAC 704.9482. My testimony focuses on the procurement plan factors, in light of the modeling and procedural process. My recommendations are intended to support both the risk management requirements of an IRP, as well as the evaluation and scheduling mechanisms of a procurement plan, including maximizing the value of competition.

[2] Nev. Admin. Code § 704.9482.

IV. The IRP Process Should Provide Certainty to the Market and Regulators through Defined Phases that Set Up and then Approve an All-Source RFP

11. Q. Please describe the purpose of this section.

A. In this section, I describe best practices in IRP process. I discuss why the Commission should find it in the public interest to have two transparent and certain phases in the IRP that integrate all-source RFPs as the focal point of the resource acquisition process in an open and transparent manner. I describe the PSCo two-phase IRP process in Colorado as one example of this process in action. I then describe how these best practices differ from those applied in this IRP and how they could assist the Commission if they were adopted for the next IRP.

A. The Purpose of a Two-Phase IRP Process is To Incorporate the RFP

11. Q. Please describe a high-level framework for IRP process best practices.

A. The IRP best practices evaluation published by Energy Innovation, *et. al.*, in 2020 lists four high-level frameworks for IRPs (plus a recommendation to review IRP rules):

> 1. Regulators should use the resource planning process to determine the *technology-neutral procurement need.*
> 2. Regulators should require utilities to conduct a *competitive, all-source procurement process, with robust bid evaluation.*
> 3. Regulators should conduct *advance review and approval of procurement assumptions and terms.*
> 4. Regulators should renew procedures to ensure that utility ownership of generation is *not at odds with competitive bidding.*[3]

[3] MDD-2 at 3 (Emphasis added.)

More recently, the Rocky Mountain Institute (RMI) published a paper in 2023 entitled "Reimagining Resource Planning" and similarly found that a comprehensive IRP practice is to "establish a common set of assumptions and evidence that can be used to assess which near- and long-term options can meet system needs and achieve desired utility performance across multiple objectives."[4] The RMI and Energy Innovation reports are just two among several that reveal the conclusion that where IRPs follow the principles of using advanced review of modeling assumptions prior to an RFP, and incorporating the all-source RFP as the critical element of the IRP, the resulting competitive all-source solicitations produce robust, low-cost bids that benefit ratepayers and manage utility risk.[5]

12. Q. What types of risks are addressed in an IRP?

A. There are several. One is of course "resource adequacy," *e.g.*, whether the utility has enough supply to meet evolving demand and system needs. IRPs can also help to avoid the opposite risk of over-building supply or creating stranded assets. Other risks include constraints on transmission, gas pipeline capacity, and greenhouse gas emissions risk. Additionally, IRPs can manage cost and risk to strike a balance of UOG and PPA projects. In recent years, several utilities have experienced massive construction cost overruns for large UOG projects. IRPs can reduce this risk by not "putting all the eggs in one basket" in terms of ownership, technology, or timing.

13. Q. How does the IRP process manage these risks?

A. The primary tools are system modeling software for capacity expansion, production cost, reliability, and ratepayer cost. Some models can consider all of these variables at

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[4] Mark Dyson, Lauren Shwisberg, and Katerina Stephan, Reimagining Resource Planning, RMI, 2023, at 16, *available at* https://rmi.org/insight/reimagining-resource-planning/. Attached as **Exhibit MDD-3.**
[5] MDD-2 at 19, 32.

once. NV Energy uses two models, PLEXOS and PROMOD, for system expansion. Modeling software products forecast different futures based on their inputs. Capacity expansion models evaluate what resources best expand the system to meet the resource need while balancing costs and other constraints placed on the model, *e.g.*, emissions limits. Production cost models solve for the dispatch of electric generation based on economics and other constraints. Reliability models stress the ability of the modeling results to avoid a loss of load from a transmission and extreme conditions standpoint.

14. Q. Please explain how capacity expansion models forecast different futures.

A. A given capacity expansion model's simulation efficacy is dependent on its inputs. Chief among those inputs are resource need and candidate resources to fill the resource need. Utilities typically start by constructing a "base case," as NV Energy did here, depicting its system as it is today. The capacity expansion model then runs its algorithm to select candidate resources as it determines are needed and produces resource portfolios that cost-effectively expand the system, often based on the net present value of revenue requirements (NPVRR). This is what I refer to as an "optimization run".

In a base case modeling run, the utility inputs assumptions for load, transmission constraints, externalities such as the Social Cost of Carbon, and assumptions regarding the "tail" of the planning period when resources must be replaced in the model. In a base case, candidate resources are input by the utility, by which I mean a utility creates "generic" units of various technologies that the model can select to fill the identified need.

15. Q. What are "generic" units?

A. Generic units are resources created in the model by the utility as placeholder candidates for selection to meet the resource need. They are sketches of potential generation and not actual projects. Generic resources may rely on estimated values, *e.g.,* National Renewable Energy Lab (NREL) data instead of recorded wind speeds at a site, or manufacturer data for a heat rate for a gas plant. An interconnection point may be selected to assist the model, but again there is no actual site and thus no actual interconnection costs.

16. Q. Are there flaws with "generic" resources?

A. Not flaws *per se*, so much as incomplete information. Generic resources are put together by utility planners, not independent companies seeking to build an actual project. Generic resources therefore can't be evaluated from a real-world perspective. They are useful for high-level, indicative analyses, but do not represent specific resource options.

17. Q. What are optimized resource portfolios?

A. These are alternate scenarios that the model "solves" for in capacity expansion runs, based on approved constraints. Resource portfolios can test for different assumptions, *e.g.*, different levels of UOG vs. IPP ownership, specific units proposed to be built or retired by a utility as an on/off look or considering back-up bids by removing the bids selected in the primary modeling runs. There can be different emission requirements, renewable acquisition levels, or storage targets. Different portfolio optimization runs may, but do not always, change the resulting resource mix the model selects from the bid pool. In any event, the output gives the Commission a full picture of options to weigh in Phase 2.

18. Q. How does a two-phase process implement these best practices?

A. Utilities' modeling practices have a significant impact on IRP outcomes. Thus, using an initial phase of the IRP to understand the key assumptions driving the modeling outcomes in the base case, and the inputs driving the resource need, are worth considering on their own merits before a regulatory body approves spending hundreds of millions of dollars based largely on modeling results.

The first phase of an IRP can also set transparent acquisition targets for the RFP that assist the utility, the Commission, and market participants to understand the rules of the road. Additionally, if new transmission investments are contemplated during the resource acquisition period, those investments should be considered in Phase 1 so that they are made available to the market in the RFP.

In a two-phase process, bids supply the candidate resources to the capacity expansion model during the resource acquisition period, and generic units are solely used as placeholders in the outside years. Capacity expansion models are designed to evaluate numerous combinations of potential projects and produce optimized portfolios. Using an all-source RFP where renewable energy can provide capacity to the system in line with the utility's approved Effective Load Carry Capacity (ELCC) studies lets different generation types compete on a level playing field. Using Phase 2 to evaluate and incorporate the results of an RFP, including proposals for both PPAs and UOG, provides direct and current market data for the Commission to examine to fill the resource adequacy need. These factors allow for a robust and transparent Phase 2 analysis that can give regulators confidence that the projects selected satisfy both resource adequacy and transmission need in a cost-effective and reliable manner with real projects.

19. Q. What are the benefits of reviewing modeling characteristics in a Phase 1?

A. The assumptions in the base case can be tested without the pressure of generation units already presented for approval. If done in advance of resource acquisition, the base case can be modified, if the Commission determines it necessary, ahead of an RFP and without having to decide on utility proposals for new generation. Importantly, this doesn't preclude a utility from presenting a UOG proposal in Phase 1, but the approval of such a proposal should be evaluated against proposals from the market. Vetting modeling assumptions in Phase 1 also provides transparency and stakeholder buy-in. The capacity expansion model can then be leveraged for its primary purpose in Phase 2.[6]

20. Q. What is the focus of Phase 2?

A. The purpose of a Phase 2 process is the all-source RFP. The Phase 2 process can be truncated where most modeling issues are decided in Phase 1, including the parameters of the utility's bid evaluation and presentation to the Commission. In that respect, the decision can focus on cost, reliability, and which of the portfolios best meet the resource need. I discuss the all-source RFP in Section V, below.

B. PSCO is one example of a two-phase IRP success story.

21. Q. What is an example of positive results accruing from a two-phase process?

A. A good example is the 2016 PSCo IRP in Colorado, which led to an RFP in 2017 and resource acquisitions decided in 2018.[7] I attach a slide from a recent IPP industry conference visualizing the Colorado process as **Exhibit MDD-4.** Exhibit MDD-4 summarizes the process, the features, and the results of the two-phase process used in Colorado.

22. Q. Please provide an overview of the Colorado IRP process.

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[6] MDD-3, at 46-47.

[7] Colorado Public Utilities Commission, *Phase II Decision Approving Retirement of Comanche Units 1 and 2; Approving Resource Selection in Colorado Energy Plan Portfolio; Setting Requirements for Applications for Certificates of Public Convenience and Necessity; and Setting Requirements for the Next Electric Resource Plan Filing*, Decision No. C18-0761, Proceeding No. 16A-0396E (August 27, 2018). See also Decision No. C17-0316, *Phase I Decision Granting, With Modifications, Application for Approval of 2016 Electric Resource Plan* (Phase I Decision) Proceeding No. 16A-0396E (March 23, 2017).

A. Like Nevada, Colorado relies on capacity expansion modeling as the backbone of the IRP, which by rule utilities must bring forward every four years. While PLEXOS is used in demand side management (DSM) analysis, DSM and retail distributed generation are approved in separate applications and the results of those proceedings feed into the IRP modeling as inputs. Capacity expansion for utility-scale resources is currently done using the EnCompass model (formerly the Strategist model), competitors with PLEXOS that are likewise multi-criteria decision analyses, differentiated in how the model "solves" for the resource need. There are analogous studies to those presented here for renewable and storage ELCC, transmission costs and resource integration, load and fuel cost forecasts, and other parameters. Notably, like Nevada, Colorado also has Renewable Portfolio Standard targets and statutory emissions reduction requirements incorporated into the IRP.

23. Q. How is the IRP decided by the Commission?

A. The IRP (called an electric resource plan, or ERP, in Colorado) is bifurcated into two phases. In Phase 1, the utility presents an application like the IRP, which also includes proposed RFP instruments for Commission review which allow the Commission to ensure predictability and fairness in the procurement. Base case modeling scenarios are presented in the utility's discretion and studies like ELCCs provide supportive information. The litigation in Phase 1 centers on the modeling assumptions that will be used to conduct the all-source RFP bid evaluation, including the resource adequacy need, the provided studies, the RFP documents as well as model contracts, and other policy matters. The Commission also makes key decisions on what will be presented and evaluated in Phase 2. This primarily includes: (1) resource portfolios to be presented including potential plant retirements, (2) the resource need, either as a point or range, and (3) the bid evaluation criteria and key reporting parameters desired to be presented in Phase 2.

The Colorado Commission states that "[i]n Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources. In Phase II, the Commission determines whether the utility should be granted a presumption of prudence for pursuing the acquisition of particular resources."[8] The resource need is principally measured on an annual basis for a summer peaking system. However, no decisions are made in Phase 1 as to the resources to fill the capacity need. The Commission issues its Phase 1 Decision, directing the utility to conduct the all-source RFP within the parameters defined by that decision.[9]

In the interim period prior to the RFP, the utility may update its load and resource balance as appropriate and without further approval. The RFP bid due date starts a 120 – 150 day clock until the utility's Phase 2 Report is due to begin the Phase 2 process.

24. Q. Does the capacity expansion model attribute firm capacity values to renewable resources?

A. Yes. ELCC studies are used to assign a firm capacity credit or reliability contribution to renewable and storage technologies in the model. In the 2021 PSCo ERP, where Phase 1 has been completed and the Phase 2 all-source RFP is underway, ELCC values varied for incremental additions based on geographic location and technology. Importantly, stakeholders had the opportunity to vet the ELCC, and a refined study was produced as part of a settlement. The ELCC represents a risk-adjusted figure for capacity based on the 8760 hourly analysis. There is

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[8] Id. *at 4.*

[9] Colorado Public Utilities Commission, *Phase I Decision addressing the application for approval of the 2021 electric resource plan and clean energy plan and approving in part, the updated non-unanimous partial settlement agreement,* Decision No. C22-0459, Proceeding No. 21A-0141E, at 6. ("…we further authorize Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2028. We also approve the process for evaluating bids to the competitive solicitation and establish the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in compliance with this Decision.")

not a performance guarantee associated with renewable resources, though PPAs do contain availability requirements, because capacity values are factored into total system capacity and not singled out for reliability on a one-off basis. There are contractual remedies for performance deficiencies in the agreements ultimately reached with winning bidders.

25. Q. What occurs in Phase 2 of an ERP?

A. In Phase 2, the utility issues the all-source RFP, and files its bid report 120 days after bids are received (the "Phase 2 Report"). The 2021 PSCo RFP includes separate RFP forms for intermittent, dispatchable, and semi-dispatchable resources. These separate forms facilitate the initial screening process, in which bids are categorized by resource and reviewed for minimum eligibility criteria and a "fatal flaw" analysis. The initial economic screening also consists of calculating an "all-in" levelized energy cost (LEC).

From that initial review, however, bidders are notified whether their projects will proceed to the modeling phase and, if so, bidders are provided the modeling assumptions that will apply to their project(s). Bidders may dispute those assumptions within a limited time window. Pursuant to the ERP Rules, and contingent upon the existence of sufficient bids passing through bid eligibility and due diligence screening, the Company sends to the portfolio development phase a sufficient quantity of bids from each RFP across the various generation types such that alternative expansion plans can be created. These alternative plans conform to the range of scenarios for assessing the costs and benefits from the potential acquisition as specified in the Phase 1 decision.

The Company develops the multiple portfolios directed by the Phase 1 Decision, although it may create additional portfolios in its discretion, each using capacity expansion plan functionality with different assumptions or constraints. In 2016, PSCo selected 160 bid alternatives for modeling evaluation.[10] The Commission then receives comments from parties on the Phase 2 Report, as well as the report of an Independent Evaluator (IE), and subsequently issues its Phase 2 Decision, without a hearing.

26. Q. How does PSCo use the EnCompass Model in the portfolio optimization process?

A. With the disclaimer that this is the first ERP where the EnCompass model is being used by PSCo, EnCompass is a mixed-integer model that produces one optimized portfolio as the solution. NV Energy describes PLEXOS as a linear model that may create hundreds of different optimized portfolios. Each model will select from the bids available to meet reserve margin and other criteria, for example bids that are mutually exclusive because they are the same bid with different in-service dates. Once a model has the guidelines and rules, the capacity expansion tool will build the scenarios and the model then the production cost function dispatches the existing generation fleet plus the portfolio. NV Energy uses an entirely separate model, PROMOD, for this function.

27. Q. What are the contents of a Phase 2 Report?

A. The contents are dictated by the Phase I Decision. The Phase 2 Report centers on the results of the capacity expansion modeling and bid evaluation exercise. I have attached the 2016 PSCo Phase 2 Report on the results and analysis of the all-source RFP.[11]

In the 2016 Phase 2 Report, PSCo presented a representative sample of the top performing portfolios that it selected from its capacity expansion modeling. These portfolios are optimized for

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[10] Xcel Energy Colorado, *2016 Electric Resource Plan, Public Refile of 120-Day Report*, CPUC Proceeding No. 16A-0396E (June 6, 2018) (the "Phase 2 Report"), **Exhibit MDD-5.**

[11] Exhibit MDD-5.

different criteria, include the utility's preferred portfolio, a least-cost NPVRR portfolio, and other portfolios that address including increasing amounts of renewables and other alternatives to the preferred portfolio.

Using the optimized portfolios, PSCo also presents the production cost module runs, including runs that change pricing assumptions and thus dispatch. These are the "sensitivity analyses" where the model can respond to different inputs for fuel price, load growth, carbon pricing, among others. The production cost module cannot "optimize" or select bids, only change pricing parameters to affect dispatch. The sensitivities are similar to this NV Energy IRP, including high carbon cost, high and low gas forecast, and load growth, etc. The Commission receives comments from parties and a reply by the utility, as well as the IE Report (which in Colorado is focused on process more than vetting the model results).

28. Q. How did the all-source bidding process work in the 2016 ERP?

A. In the 2016 PSCo ERP, PSCo proposed to retire two coal fired generating units with a total capacity of 660 MW in a Phase 1 amendment.[12] However, the same two-phase process took place. With native load growth and reliability capacity need established at 450 MW, the Commission approved a resource need in Phase 1 to procure 1100 MW of additional capacity resources during the resource acquisition period in its all-source RFP.[13] The bidding was divided by intermittent RFP, dispatchable RFP, semi-dispatchable RFP, and then among PPA or build transfer agreement (BTA) proposals. All of the bid proposals were evaluated together in the model as capacity resource options, however.

[12] Due to the timing of the proposal, an additional hearing was conducted on the proposed retirement process.
[13] MDD-5, at 16. Because the resource acquisition period ended in 2023, Xcel deferred some capacity need due to the proposed retirement of the Comanche 2 Unit in 2025.

29. Q. What was the scope of the bids received by PSCo all-source RFP?

A. Xcel received 417 bids from 238 distinct projects totaling approximately 58,000 MW of capacity for a resource need of 1100 MW.[14] Of the 417 total eligible bids, 160 bids for 79 distinct projects were advanced to computer-based modeling.[15] The large resource need, and the open competition to fill that need from both a capacity and energy basis, attracted nationwide attention to the PSCo RFP.[16]

30. Q. What were the results of the all-source RFP?

A. The Commission approved PSCo's preferred portfolio of 1100 MW annual firm capacity need. Pursuant to that need, PSCo acquired the 2458 MW of nameplate capacity resources as the preferred portfolio from its all-source RFP:

- 1,100 MW wind[17]
- 700 MW solar
- 275 MW battery storage, paired with solar
- 383 MW gas CTs through re-contracting or purchase

As can be seen in these results, the capacity expansion modeling, when allowed to select renewable resources based on their ELCC capacity values, did select wind and solar resources to meet a part of the capacity need and did not select new gas generation.

31. Q. At what prices were these resources acquired?

[14] MDD-54 at 79.
[15] *Id.* at 85.
[16] *See e.g., "Xcel solicitation returns 'incredible' renewable energy, storage bids,* Utility Dive, dated Jan. 8, 2018, *available at* https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/
[17] Colorado Public Utilities Commission, *Phase II* Decision No. C18-0761, Proceeding No. 16A-0396E at 42 (August 27, 2018), referencing MDD-5.

A. The indicative pricing in the Phase 2 Report states that PSCo's preferred portfolio included "[u]nprecedented low pricing across a range of generation technologies including wind at levelized pricing between $11-18/MWh, solar between $23-$27/MWh, solar with storage between $30-$32/MWh and gas between $1.50 - $2.50/kW-mo."[18] PSCo has since described its final contract prices for renewable energy as the lowest in the nation. Although this pricing is pre-pandemic, and PSCo has felt the solar industry challenges that NV Energy has, the point is that there were impressive numbers of low-cost bids, indicating a robust market response to the RFP process. This market response was stimulated in part by the predictable nature of the resource planning and procurement processes.

Table MDD – 1: PSCO Table of 2017 RFP Responses by Technology (Public re-file)[19]

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	29	6,365	19	4,436	$ 5.08	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.21	$/kW-mo
Gas-Fired Combined Cycles	3	873	3	873	7.56	$/kW-mo
Stand-alone Battery Storage	28	2,144	24	1,945	10.53	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	14.62	$/kW-mo
Wind	96	41,915	42	16,949	$ 19.30	$/MWh
Wind and Solar	5	2,601	4	2,151	19.96	$/MWh
Wind with Battery Storage	11	5,700	5	2,700	20.63	$/MWh
Solar (PV)	148	28,382	78	14,085	30.96	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.41	$/MWh
Solar (PV) with Battery Storage	79	14,980	57	10,098	38.30	$/MWh
IC Engine with Solar	1	5	1	5	41.42	$/MWh
Waste Heat	2	21	1	11	56.90	$/MWh
Biomass	1	9	1	9	153.51	$/MWh
Total	418	108,163	246	58,101		

[18] MDD-5, at 51-52.
[19] MDD-5, at Attachment 4.

Follow-on applications for CPCNs are required for resources that were to be utility-owned and new transmission facilities, but PSCo otherwise moved forward to contract with facilities that were in the selected portfolio without further approval.

32. Q. Did the two-phase approach lead to ratepayer savings?

A. Yes. The second key point that can be seen from the PSCo RFP results is the effect of portfolio optimization. The Colorado Commission found that the preferred portfolio could save ratepayers more than $200 million in NPVRR savings over the portfolios term versus that of continuing to run the candidate plants for decommissioning in that ERP on an economic basis.[20] PSCo's bid portfolios, approved in the Phase 1 Decision, enabled the Commission to evaluate costs of resource alternatives. **Table MDD-2** shows Table 8 portfolios of bids from the Phase 2 Report compared for the Commission's decision with the final rows comparing revenue requirements of the various portfolios:

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[20] Colorado Public Utilities Commission, *Phase II* Decision No. C18-0761, Proceeding No. 16A-0396E at 29-30 (August 27, 2018).

Table MDD-2: Table 8 – Bid Portfolio Analysis Summary Results (Annuity Method)

Table 8 - Bid Portfolio Analysis Summary Results (Annuity Method)

		ERP 0 MW Portfolio	ERP 450 MW Portfolios (Com 1 & 2 Continue Operation)			CEP 1110 MW Portfolios (Early Retire Com 1 & 2)				CEP 775 MW Portfolios (Early Retire Com 1)		
Portfolio #		1	A2	[redacted]	4	A5	[redacted]	7	A8	A9	10	A11
Portfolio Name		LCP	LCP	[redacted]	All Thermal	LCP	[redacted]	Full Replacement	MLEP	LCP	500 Owned	MLEP
Nameplate Capacity (MW)	Notes:											
Solar		0	457	[redacted]	0	707	[redacted]	707	807	382	457	510
Wind		789	789	[redacted]	0	1131	[redacted]	1131	1131	1131	1131	930
Storage		0	150	[redacted]	0	275	[redacted]	275	150	150	150	250
Gas		0	147	[redacted]	583	530	[redacted]	530	583	530	383	383
Total Nameplate MW		789	1543	[redacted]	583	2643	[redacted]	2643	2672	2193	2121	2073
Owned EER MW	1	0	0	[redacted]	0	0	[redacted]	500	800	0	500	599
Owned D/SD MW	2	0	0	[redacted]	583	383	[redacted]	383	583	383	383	383
Owned EER %	3	0%	0%	[redacted]	0%	0%	[redacted]	27%	41%	0%	31%	42%
Owned D/SD %	4	0%	0%	[redacted]	100%	48%	[redacted]	48%	80%	56%	72%	61%
RAP Firm Capacity (MW)												
Total Firm Capacity	5	79	547	[redacted]	534	1125	[redacted]	1125	1132	872	780	866
Excess of 2023 Need	6	(375)	93	[redacted]	80	346	[redacted]	346	353	93	0	87
2023 Reserve Margin %	7	11.0%	17.6%	[redacted]	17.4%	21.2%	[redacted]	21.2%	21.3%	17.6%	16.3%	17.5%
Planning Period PVRR ($M)												
Base Portfolio	8	$34,522	$34,394	[redacted]	$35,366	$33,872	[redacted]	$33,952	$33,966	$34,001	$34,056	$34,161
Electric Interconnection	9	$14	$57	[redacted]	$4	$73	[redacted]	$73	$97	$45	$57	$46
Electric Delivery	10	$113	$149	[redacted]	$1	$113	[redacted]	$113	$149	$113	$149	$113
LCI and Voltage Control	11	$12	$12	[redacted]	$6	$44	[redacted]	$44	$44	$44	$44	$23
DTA	12	$0	$0	[redacted]	$0	$0	[redacted]	$82	$203	$0	$82	$103
Operating Reserves	13	$7	$7	[redacted]	$0	$30	[redacted]	$30	$30	$30	$30	$13
Total PVRR		$34,667	$34,618	[redacted]	$35,377	$34,133	[redacted]	$34,294	$34,490	$34,232	$34,418	$34,458
PVRR Delta vs Preferred ERP	14	$17	($31)	[redacted]	$727	($517)	[redacted]	($355)	($159)	($417)	($231)	($192)

33. Q. What is your conclusion regarding best practices and for IRP decision-making?

A. Using a two-phase process can be considered best practices in IRP planning because it incorporates a predictable RFP and centers on capacity expansion optimization using the primary functionality of the models. The critical components of the two-phase approach are first to approve modeling assumptions, bid evaluation criteria, and potential portfolios the Commission will review after the RFP is conducted. The second phase then involves a transparent selection of resources on an optimized portfolio basis and within a definite timeframe. This has the benefit of creating certainty for the market participants as well as for regulators and has been shown to result in low-cost bids and ratepayer savings.

C. The 2024 NV IRP Should Follow the Two-Phase IRP Process

34. Q. What is your understanding of the process used in this NV Energy IRP?

A. This triennial NV Energy IRP was filed on June 1, 2021. At that time, the IRP was divided into three phases. The first phase concerned short-term upgrades to certain gas-fired generators and 66 MW of battery storage and was driven by reliability events the California Independent System Operator (CAISO) experienced in 2020.[21]

The IRP was amended on Sept. 1, 2021, adding Phase IV, even as a hearing was held on Phase I on Sept. 8, 2021, and prior to a separate hearing on Oct. 5, 2021 on certain IRP assumptions, including the load forecast, where a Phase II stipulation was approved.[22] A stipulation to the First Amendment was approved in July 2022 for several projects in various stages of contracting or review by NV Energy.

In Phase III, an order was issued on Dec. 28, 2021, prior to the First Amendment order approving other resources, and investments in solar and gas. PLEXOS and PROMOD were introduced as modeling tools, as well as a new planning reserve, among other approvals. Phase IV of the 2021 IRP involved a stipulation that was approved by Commission order issued on Jan. 26, 2022.

Only one year later, this Fourth Amendment now seeks to cancel or amend several of the IRP decisions, including the Phase III generation decisions. The changes add significant generation and transmission decision points that equate to nearly a full IRP in and of itself. In each phase or

[21] PUCN, Phase I Order.
[22] PUCN, Phase III Order.

amendment, notice and publication and motions to intervene are accepted by the Commission. The Company anticipates another (fifth) amendment after this in 2023.[23]

35. Q. When is the next IRP due?

A. The next triennial IRP is due in summer 2024, a little more than one year away. The Company does not intend to solicit feedback prior to final decisions and filing.[24]

36. Q. How did NV Energy describe their modeling approach?

A. The Company uses PLEXOS for capacity expansion in development of long-term plans with future placeholder resources, *i.e.*, with generic resources, to fill the open positions in their Load and Resource tables. PROMOD is used as a production cost model, performing hourly, chronological economic unit commitment and dispatch.[2] The Company then uses a spreadsheet model to derive revenue requirements separately from the two models, though the software models also have this capability.[25]

37. Q. What RFPs have taken place?

A. NV Energy issued three utility-scale RFPs during the pendency of the 2021 IRP four phases and four amendments. NV Energy issued a Spring 2022 RFP, a 2022 "PURPA RFP" seeking resources from 50 – 100 MW, and then a Winter 2023 RFP that was "on the street" about two months ago in January 2023. Further, the Phase 1 order in this case finds that NV Energy testified it held two additional RFPs in 2020. The Company stated no projects were selected from either 2020 or 2022 RFPs.[26]

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[23] Vol 1, Narrative, at 139.
[24] IEA 3-08 **Exhibit MDD-12.** NV Energy has scheduled a short telephone call which primarily includes a brief report-out description of the filing to come.
[2] Vol. I, Narrative, at 127.
[25] *Id.* at 128.
[26] Phase 1 order paras. 34, 35 regarding 2020; IEA 3-02 (MDD – 14) regarding 2022.

To my review, none of these RFPs were approved in any Phase or amendment order. Out of the five RFPs held since 2020, the sum of projects from those RFPs that will help fill the capacity position the Company started this proceeding with in 2021 is low - only 66 MW.[27] While NV Energy provided its reasoning both for launching the RFPs and for its decisions not to contract, the decisions are made in NV Energy's discretion separate and apart from the many phases of this ongoing IRP, without supporting data presented to the Commission. In the interim, the Company has pursued self-build options at Silverhawk, and executed PPAs with IPP projects outside of the RFP process.

38. Q. What conclusions do you draw from this process?

A. This process concerns me in three respects considering the best practices in IRP processes that I addressed above.

First, there is a disconnect between the Commission's exercise of its IRP jurisdiction on the one hand, and RFPs conducted by the utility on the other. This means that the process of soliciting and evaluating new resources, arguably the primary purpose of the IRP, has limited or even zero examination in the IRP, even as multiple RFPs take place in parallel. While NV Energy's subject matter experts are no doubt capable and the utility has the best insight into its resource needs, the disconnect here is stark.

If RFPs are not considered in the IRP process except as individual projects may be randomly put forward during a three-year litigation process in the utility's sole discretion, then there is less information exchange, less transparency into what the market can provide, and ultimately weakened decision-making that may not be reflective of the ratepayers' best interest.

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[27] *Id.* at 34 - 35.

While Phase II tackled some modeling inputs, in no phase were the modeling assumptions or detailed results of bid evaluations ever put forward for the Commission to review.[28] That these RFPs are taking place in the shadow of the IRP decisions rather than being guided by them is a lost opportunity.

Second, if you are an RFP bidder, you have no certainty your bid will ever be analyzed, much less brought before the Commission, despite the terms of the RFPs that list exact decision dates. The projects bid into the multiple RFPs were not examined by the Commission. Such IPP bid data sits in NV Energy's database, ostensibly as a well for later use. So, although it is to its credit that NV Energy issues regular RFPs, the process is ambiguous, unpredictable, and uncertain from the market's perspective.

Third, for parties like Interwest, and more importantly the Commission, Commission Staff, consumer representatives, and other stakeholders, there has been constant IRP litigation during the IRP period. There is no finality where the next IRP phase or amendment comes on the heels of the last, overlapping at times, with later phases undoing earlier phases. This makes the whole process opaque and leaves little chance for parties to review whether the IRP as a whole produces the best results for ratepayers.

39. Q. What problems does this potentially create for the Commission?

A. First, the IRP process creates uncertainty, and that creates risk. IPPs may have participated in several RFPs without seeing any be concluded. The Company says projects from older RFPs may be brought forward in the future. However, it's likely that all 2020 bids, and likely even 2022 bids, can no longer honor their pricing from the time the bids were submitted.

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[28] IEA 2-09, **Exhibit MDD-6.**

This also means that the significant work, and the $10K initial-level bid fees for each project, are for naught.

In addition, the Commission's diligence is hampered by not reviewing resources via its primary risk management tool, the capacity expansion model. Instead, resources have been acquired at different times via different applications, all within this three-year window before the process starts again. So, when a project goes wrong due to the overwhelming global market forces of 2021-2022, for example, there is little evidence to support what could have been, or what can still be done, as an alternative. This gives NV Energy the controlling ability to suggest a course correction, absent things like back-up bids, wait lists, or bid refresh opportunities.

40. Q. Did the Company use its capacity expansion model to identify and fill the capacity need in this IRP?

A. While the Company ran its model, it did not fill the capacity need and did not follow the model's initial results. The Company states that "… in the 2021 IRP, the preferred plan's open capacity position indicated a need for 630 MW in Southern Nevada in 2024 and 450 MW in Northern Nevada in 2025. These years are mentioned as they correspond to the expected in-service dates of the majority of proposed resources in the Fourth Amendment."[29] However, these numbers are not mentioned in the 2022 or 2023 RFPs. This means that bidders are not aware of the market conditions created by NV Energy's resource need.

The Company's alternatives then do not fill the resource need but leave "placeholder" capacity as soon as 2025.[30] The Company states that it "reviewed a number of resources when

[29] IEA 2-10, **Exhibit MDD-7**.
[30] Vol 1, Narrative at 140.

building the Preferred and Alternate Plans."[31] However, the Company did not proceed under its own base case result that did not select a CT.[32] Instead, its alternative plans were hand-picked combinations of its preferred projects.[33] If this were a first phase, those alternative plans would provide information to the Commission it could use in fashioning Phase 2 requested portfolios. Instead, however, those alternatives are the bases for approval of the generating units studied in the base case.

41. Q. Could the two-phase process have helped to avoid the current shortfall situation?

A. It is unclear; hindsight is always 20/20. With that caveat, I note that NV Energy testified that it rejected projects in its 2020 RFPs with an in-service date beyond 2022.[34] Had the Commission evaluated and approved resource portfolios for contracting/in-service later than 2022, it's possible that there might now be planned capacity coming online in 2024 and 2025 to alleviate the urgency behind this Fourth Amendment. I don't know if that would have been the result, but I do know there is no chance for a different result because the RFP decisions were made without Commission review in what was being solicited, for when, and how bids were evaluated.

42. Q. Are the lack of all-source bid reports or resource portfolios an issue of concern here?

A. Yes. Resource decisions are siloed between different projects in different phases. The Company models alternatives with generic unit combinations and does not test those hypotheses against the market. There is no comprehensive review that would give the Commission

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[31] Vol. 1, Application, at 44.
[32] Vol. 1, Narrative at Figure EA-2 does not show any CT being selected by the model in the base case.
[33] Vol. 1, Narrative, at 138.
[34] PUCN, Phase 1 order. at ¶¶34, 35.

an opportunity to approve an optimized portfolio of resources. There is no comprehensive review of various ownership models, resource types, in service dates, or interconnection locations that can each significantly affect the rates that ultimately flow from resource acquisitions. Simply put, this means the process obfuscates the window into all that is being approved for acquisition.

43. Q. Could a two-phase approach have been implemented here?

A. It seems so. Most of the elements needed for a Phase 1 are within the docket and RFPs have taken place, just offline, or spread around to different phases and amendments. I note with approval the integration of transmission costs as a follow-on phase after studies are complete, however if transmission expansion opportunities are approved prior to RFPs then bids can aim at filling the new capacity made available.

44. Q. Are there due process benefits that would result from moving to a two-phase process in the next IRP?

A. Yes. If in the next IRP, the Commission orders two phases to define the issuance of an RFP and the RFP timeline with certain decision points from Commission, this will benefit stakeholders and the public interest. First, parties will be able to comment on modeling and bid evaluation before-the-fact to assist Commission evaluation. Second, parties will be able to integrate information from the RFP bids submitted, assisting the Commission's evaluation of the market results as against the utility's proposals, if any. The result is likely to be a more robust and transparent review that in turn leads to ratepayer savings through competitive pressure and an optimized portfolio.

V. The IRP Should Result in All-Source RFP

45. Q. Please explain the purpose of this section.

A. This section focuses on the import of an all-source RFP prior to a Phase 2 Decision. I show the value of an all-source RFP both in terms of ratepayer savings and renewable energy competition. I show how the all-source RFP process could have engendered a different result in this docket than the shortfall before the Commission, and why it is important to change the process for the next IRP.

A. All-source Procurement Leverages System Studies and Modeling

46. Q. Please define all-source RFPs.

A. All-source procurement means that when a utility enters a new generation acquisition process, the utility conducts the acquisition process evaluating an RFP via capacity expansion modeling, and the regulators timely review and approve resource portfolios. In the all-source process, the requirements for capacity or energy resources are neutral with respect to technologies or combinations of resources available in the market. Considering the market power that vertically integrated electric utilities have, regulators can effectively leverage all-source procurements to gather market data and compare that to utility analyses. The result is a better-balanced mix of resource technologies and ownership for ratepayers and the environment.

47. Q. What are the benefits of a balanced mix of ownership for generation resources?

A. The principal benefits are an allocation of costs and risks and increased competition. UOG generation has more regulatory oversight than PPA generation and can benefit from utility low cost of capital. PPAs spread ratepayer risk from construction cost overruns or operational problems because IPPs must hold their bid price, while a utility may request increased revenue requirements. The risk of underperforming generation is also an important factor to consider in a balanced ownership mix. If an IPP doesn't produce power as it contracted for, then it is not paid or must pay a penalty. Renewable generators introduce stable up-front fixed costs that avoid fuel price fluctuations such as those caused by winter storm Uri that many millions of ratepayers will be paying off for much of this decade.[35] Renewable PPAs have "baked-in" benefits of tax credits in bid pricing that need not flow through utility accounting and ratemaking to reach consumers.

Even after the resource acquisition phase, renewable PPAs offer a significantly different profile in rates as well. Generally, renewable PPAs keep the same rate structure through the life of the PPA, where UOG is generally included in rate base. Rate-based generation may be significantly more impactful to rates in the early years of an asset being in-service.

Finally, where bidders know that the market rules allow all types of resources to compete to fill a capacity need as well as system energy, there is more confidence in the market and therefore more bids/more competition. This competition is key to achieving the best information available to confidently make decisions that are in the long-term best interest of ratepayers.

48. Q. How does an all-source RFP leverage utility modeling capabilities and studies?

A. By utilizing the capacity expansion model to optimize actual project bids as compared against the modeled simulation of "generic" resources that are used in the absence of real projects. For example, in the 2016 PSCo ERP, the utility described the process as follows: "Strategist will be used in developing portfolios of proposals/bids that are advanced to this stage of the competitive acquisition. The modeling framework Public Service will employ in the Phase

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[35] See e.g., https://www.eenews.net/articles/why-energy-bills-skyrocketed-in-the-u-s-west/

II portfolio analysis is the same as that used to develop alternative plans that are discussed in ERP Volume 1. . . *except* . . . *actual bids are used to meet RAP needs instead of generic estimates* . . . ."[36]

Utilities, like NV Energy here, assign a capacity value to renewable generation and to storage. In an all-source RFP, this ELCC research allows technologies to compete to provide capacity and energy to the system. This in turn assists renewable generators to use their lower cost to defer the need for additional fossil fuel capacity resources. The model can also estimate transmission costs, fuel costs, and resource cost to optimize across a suite of resources to meet a resource need if necessary, as it clearly is for NV Energy at this time.

49. Q. Have studies concluded that an all-source RFP is best practices?

A. Yes, both the RMI and Energy Innovation reports drew those conclusions from reviewing IRP processes around the country. The RMI report found that all-source RFPs provide certainty by bringing in timely market data as a basis for making procurement decisions.[37] The report noted Washington and Colorado, where "approval of the IRP authorizes utilities to proceed with issuing an all-source solicitation for the identified need, rather than authorizing specific resources."[38] In the Energy Innovation Report, four of the case studies (Xcel Colorado, PNM, Northern Indiana Public Service Company, and El Paso Electric) demonstrated that the market for generation projects can provide robust responses to all-source RFPs versus states that do not.[39] RMI also found "an optimized clean energy portfolio is more cost-effective and lower in risk" than gas-fueled power plants.[40] This is consistent with PSCo's 2016 all-source RFP, that

[36] *See* Attachment AKJ-2 to Xcel 2016 ERP application, Colorado Proceeding No. 16A-0396E at page 2-224.
[37] MDD-3 at 12.
[38] *Id.* at 26
[39] MDD-2 at 19, table 3
[40] MDD-2 at 14.

found new gas builds were not cost-effective as against new renewables and storage facilities. Finally, an all-source RFP means that CPCNs for individual facilities, where needed, can be streamlined where a need has been determined via the all-source RFP.

50. Q. What do you conclude regarding the value of an all-source RFP?

A. I conclude that where all-source procurements are initiated with explicit determinations of need rather than a technology specification, set regulatory approval processes, and transparent evaluation, the market for generation projects can provide robust responses to all-source RFPs. The primary function of the capacity expansion model is leveraged to evaluate multiple technologies on multiple criteria. The optimum mix of solar, wind, storage, and gas resources is more effectively selected based on actual bids, rather than in a generic evaluation or single-source RFPs. This benefits regulators and ratepayers compared to an after-the-fact review that creates a number of problems, most notably that there is limited ability to review the utility's options. Simply put, the all-source RFP provides hard data on competitively bid alternatives and therefore allows for a more informed and cost-effective decision-making process benefitting the Commission, the consumer, and providing confidence to the generation market in Nevada.

B. NV Energy Did Not Hold All-Source RFPs in this IRP, and the Commission Should Act to Correct this for the Next IRP.

51. Q. Did NV Energy conduct an all-source RFP?

A. No. NV Energy created silos for renewable energy, PURPA compliant projects, and gas-fired capacity that were not evaluated in an all-source process. Then it brushed aside the RFPs and proposed projects not submitted in any RFP. Using five RFPs in three years, at different times, for different sources of generation, and ultimately selecting almost no new capacity, while not having a Phase 2 process to review such RFP results in a capacity expansion model, means there is not an all-source RFP process.

52. Q. What are your criticisms of NV Energy's use of the model in these RFPs?

A. I have three primary areas of concern. First, NV Energy did not allow the market to test its assumptions on gas-fired plant extensions but relied on generic units to test its preferred acquisitions. Second, NV Energy's assumptions in its base case capacity expansion runs did not allow renewable resources to compete to provide capacity to the system and hampered the ability of storage resources to do so. Third, NV Energy contracted for resources outside of the RFPs.

53. Q. Turning to the first concern, why do you conclude that NV Energy did not provide an optimized capacity expansion using real projects?

A. NV Energy's decision points in this Fourth Amendment are rooted in its base case model runs. No optimized capacity expansion modeling including RFP bids was utilized, or, if such modeling occurred, the Commission is kept in the dark as to its results. NV Energy states that, in considering alternative sources to contribute to the capacity and energy requirements to be filled by the projects proposed to be acquired under the Application, it included the projects requested for approval, and generic CT and BESS units located at certain system injection points.[41]

Second, as can be seen from Table REN-8 in the narrative, the resources acquired in this RFP have come in at least three tranches approved at different times with different assumptions, all within one IRP.[42] None of the resources NV Energy proposed for acquisition, including its UOG projects, can be traced to one of the three RFPs. NV Energy states that "[a]ll new units in

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[41] IEA 2-01, **Exhibit MDD-8**
[42] Table REN-8

the base case are "generic" units, also called placeholders."[43] So, none of the UOG or PPA proposed projects were evaluated against market bids.

54.` Q. Please explain why you conclude that NV Energy's assumptions in its base case did not allow renewable resources to compete effectively?

A. NV Energy made the decision to exclude renewable resources and storage as capacity options for its base case model. The Application describes "candidate resources" the model could select to fill the capacity need as follows:

> However, for the purpose of this amendment, the firm dispatchable resources are modeled with the characteristics of gas turbines due to the lack of sound data on proven, appropriate low carbon alternatives. New firm dispatchable resources could include the use of hydrogen as a fuel, fuel cells or biofuel combustion units. There were three different technology types representative of firm dispatchable generation that were modeled as candidate choices for PLEXOS LT to select:
>
> - lxl Combined Cycle Unit
> - 2xl Combined Cycle Unit
> - Combustion Turbine ("CT") Peaker Unit[44]

This means the model was constrained from considering renewable and storage resources from providing capacity credit to meet the resource need. Contrary to its narrative, NV Energy does have sound data on capacity provided by renewables: its ELCC study. NV Energy's approach guaranteed that a new gas-fired unit would be selected to meet the need, because only gas-fired resources were allowed as options.

Second, the Company makes a request in this case to extend the useful life of approximately 17 gas-fired generators.[45] Several of the gas-fired units in **Table Gen-2** would raise potential

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[43] IEA 3-07, **Exhibit MDD-13.**
[44] Vol. 1, Narrative at 135/
[45] Vol 2, p. ___, Table GEN-2 New Unit Retirement Dates; Vol. 2, p. 41 of 359, Testimony of Williams at 41.

retirement decisions for the Commission as soon as 2028, possibly in the next IRP, including the Ft. Churchill Units 1 and 2, Tracy Unit 3, or Clark Unit 4.[46] However, the model did not test these retirement decision points, as it is designed to do.[47] Instead, the plant-life extensions were "baked in" the model as firm decisions. If the plant life extensions are granted here, those units will continue to operate absent any modeling on the cost-effectiveness of these decisions and absent market responses.

55. Q. How does NV Energy describe its capacity expansion process?

A. The Company states that capacity expansion "refers to the problem of finding the optimal combination of generation new builds and retirements and transmission upgrades (and retirements) that minimizes the net present value (NPV) of the total costs of the system over a long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective."[48] This is a correct description of the issue, but it is not how NV Energy went about using the tool based on the candidate resources and gas-fired plant retirement alternatives.

56. Q. Have you experienced IRPs that evaluated retirement decisions?

A. Yes. Each of the last four PSCo ERPs has considered whether to retire generation assets. Some coal-fired units were transitioned to natural gas, and some were retired and replaced with renewable resources. But in each case the decisions were made by the Commission in the two-phase process were clearly informed by market prices in the Phase 2 Report and were tested via the capacity expansion model.

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[46] *Id.*

[47] Vol. 1, Narrative at 134 ("The PLEXOS LT analysis assumes the continued operation of many existing gas-fired units both in the north and south… [and 13 other units] in addition to those in the depreciation filing")

[48] Vol. 5 at 9.

57. Q. Was it correct to exclude renewable resources from being candidate resources in its base case?

A. No. The base case must be an impartial evaluation. It is not best practice to exclude the cheapest and fastest growing technologies in the market from an evaluation that is intended to inform the utility of its options to meet the resource need. The result of excluding those technologies in the screening process was to limit the ability of the model to accurately create potential resource portfolios based on data available in the market.

58. Q. Were the RFPs set up to provide information and certainty to market participants in the IRP process?

A. No. Neither the Spring 2022 or Winter 2023 solicitations mention the ongoing IRP process, the resource adequacy need, or even the level of capacity being sought.[49] Information given to bidders was inaccurate. For example, although the Spring 2022 RFP provides a "Table 2 – RFP Schedule" with dates for filing for PUCN approval, those dates have already passed.[50] Thus, if an IPP bid into the Spring 2022 RFP with a 2025 in-service date as required, such bids would already have difficulty financing and constructing their project in time. This erodes developer confidence that it is worthwhile to submit a bid in an NV Energy RFP, which in turn can result in attrition in the bid pool and higher bid prices.

The Winter 2023 RFP states that it is only to contract for non-renewable firm capacity and energy assets that may include energy storage and conventional generation to support system peak capacity needs and the continued integration of intermittent renewables.[51] Presumably, this

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[49] **Exhibit MDD-9**, IEA 2-04(f) 2023 Open Source RFP; Exhibit MDD-11 IEA 2-03 Spring 2022 RFP.
[50] Table 2 showed a filing by Feb. 14, 2023 associated with approval of RFP resources.
[51] 2023 RFP

excludes renewables from meeting the capacity needs of the system. The Winter 2023 RFP only allows for utility ownership of storage resources.[52]

59. Q. Were the 2020 or 2022 RFPs successful?

A. No. Little to no projects were selected. Beyond that, however, is that there was limited market interest. **Exhibit MDD-14** is an anonymous list of bids provided in discovery from the Spring 2022 RFP. The response shows only 11 projects submitted bids, for a total capacity, including bid variations, of about 10,000 MW.[53]

NV Energy's need of approximately 1,100 MW in this IRP is similar to PSCo's need in its 2016 ERP. NV Energy's solicitation response, however, was meager compared to PSCo's 2017 RFP, where a 1,100 MW need produced over 230 individual projects, with over 400 bid variations totaling nearly 60,000 MW. Given NV Energy's procurement needs, the results of its 2022 RFP demonstrate IPPs' lack of confidence in the NV Energy market. This result shows that all-source competition in a two-phase process can be more robust and produce greater ratepayer value than NV Energy's RFPs have achieved.

60. Q. Does NV Energy currently need Commission approval to issue an RFP?

A. The Company says it does not, though it references the current approach has only been in practice since 2018.[54] Thus, there is not a strong precedent for this approach.

61. Q. Are there other issues you identified in the RFP?

A. Yes, there are two issues that, if raised in a Phase 1 and prior to an RFP, might lead to a more efficient IRP outcome. First, NV Energy's approach to renewable contract

[52] Exhibit MDD-14, IEA 3-02 - 2023 RFP Questions and Answers.
[53] **Exhibit MDD-15,** IEA 3-02 - 2022 Spring RE RFP Bids Received, at columns E and H.
[54] IEA 2-05, **Exhibit MDD-10.**

terms, and second, NV Energy's concerns about the CAISO market and its future purchases. These concerns appear in the application and the RFP. While I cannot say that a different resolution of these concerns would produce a different result, I can say that it is likely these issues affected the numbers and quality of bids. The result now hinders the ability of the Commission to evaluate the proposals before it in this Fourth Amendment, and therefore raises considerable uncertainty for ratepayers.

62. Q. Please explain the issue with contract terms.

A. In the Spring 2022 RFP, for bidders submitting PPA proposals, NV Energy provided that the term of such contracts must be thirty-five (35) years.[55] That term length is excessive based on the market standard of 15 – 25 years for wind and solar projects, and 20 years for BESS. Restricting generators to a certain term, versus allowing a range based on the project, is a problematic approach. Second, the RFP requires three NV Energy options to purchase at eight, fourteen, and twenty-five years.[56] Were these provisions available to be reviewed by stakeholders, parties such as Interwest might take issue with them before the Commission. As it stands, that opportunity is not available.

63. Q. Please explain your concern with NV Energy's approach to mitigating its concerns with future regional market capacity and energy.

A. The Fourth Amendment resource need is significantly impacted by NV Energy's "continuing concerns regarding the availability and deliverability of market capacity."[57] These concerns center around CAISO day-ahead scheduling and Wheel Through priorities that

[55] At 9
[56] id
[57] Application at 32.

exist through 2024 (before the in-service date of the facilities subject to this application).[58] I do not opine on the validity of this concern, rather I note that NV Energy treated that concern in its modeling in a manner that limits the Commission's options compared to a two-phase process.

The IRP provides the Company's concerns with CAISO purchases as a key driver for its procurement decisions, including the new CT. Figure EA-1 shows NV Energy's capacity position and shows market purchases dropping approximately 80% (based on the chart, or over 1000 MW), in 2024-2028, regaining most of the purchases by 2030.[59] The reduction in market capacity is due to new resources coming online, not a reduction from CAISO purchases.[60]

For this CAISO uncertainty, a two-phase process would better handle the risk as a future to be explored in a different portfolio outlook, *i.e.*, a "low market purchase" portfolio, rather than presented as fact. In that event, the risk of CAISO market purchases falling significantly could be considered, but so could a continued market purchase level portfolio using a five-year average, for example, or perhaps a "high market purchase" scenario as a counter balance. The goal would be for the Commission to review how the model selects resources under different futures. Further, in sensitivity analysis, the production costs could be evaluated with different market price sensitivities, indicating that if CAISO market purchases were available, they might be more costly. None of that kind of alternative analyses are presented in this case, but it is exactly the type that could be presented in a two-phase process that set up proposed portfolios for Phase 2.

64. Q. Do you have concerns with the geothermal PPAs?

A. Yes. Although I support PPAs and geothermal energy, I have concerns that

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[58] *Id.* at 37.
[59] Figure EA-1, Narrative at 133
[60] Exhibit MDD-16, IEA 3-04.

even the PPAs in this fourth amendment were executed based on an unsolicited offer made outside of the three RFPs that have been released.[61] I am not strictly opposed to IPPs making unsolicited offers, but the purpose of an RFP, which the Company undertook during the same period, is to solicit offers to be compared against one another. One red flag here is that NV Energy proposes paying the nearly the same price for a 120 MW unit as a 20 MW unit, implying that the Company did not capture economies of scale.[62]

65. Q. What are the problems in market transparency presented by the four phase and four amendment process here?

A. The Commission has approved generation acquisitions based on the base case only. The Company has not leveraged its capacity expansion modeling to evaluate bids, at least in a way presented to the Commission. Second, the Company in its base case put its thumb on the scale by making assumptions about gas-fired capacity without testing the market. Third, bidders who responded to the RFP were left without follow-up and the RFP shows a low level of market confidence.

66. Q. What do you recommend for the next IRP?

A. I recommend that the Commission establish a two-phase IRP process. In Phase 1, the Commission should set the goals and expectations for an all-source RFP and Phase 2 Report. In Phase 2, the Commission should approve resources acquired competitively that are tested against UOG or modeling assumptions and optimized as a portfolio approval. Projects that are not competitively acquired from an all-source RFP approved by the Commission should be

[61] IEA 2-03, **Exhibit MDD-11.**
[62] Vol 1, Application at 12-13

tested and approved by the Commission only after specific findings in a Phase 2 process and should be the exception and not the rule.

67. Q. Does this conclude your testimony?

A. Yes, thank you.

STATE OF COLORADO)
)
ss.)
)
COUNTY OF BOULDER)

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, Mark Detsky, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

MARK DETSKY

SUBSCRIBED AND SWORN TO BEFORE ME
this 16 day of March, 2023.

Emily Sessa
NOTARY PUBLIC

EMILY STURGEON SESSA
Notary Public
State of Colorado
Notary ID # 20134043658
My Commission Expires 07-15-2025

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of March, 2023, a true and correct copy of the foregoing Direct Testimony of Mark D. Detsky on behalf of Interwest Energy Alliance was served to the persons listed below by electronic mail, if an email address is provided, or by U.S. Mail, postage-pre-paid, at the addresses listed below:

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EXHIBIT MDD-1

Docket No. 22-11032
Interwest Energy Alliance
Prefiled Direct Testimony of Mark Detsky, Esq.

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State of Colorado Bar, admission December 2003

Shareholder/Attorney — *Boulder, CO*
Dietze and Davis, P.C. — *7/09 - present*

- Public Utilities and Electric Generation:
  - Colorado Public Utilities Commission practice, including representation of independent power producers, low-income consumer advocates and DSM/solar providers, demand side management companies and trade group, gas and water utilities, developers of renewable energy and natural gas projects.
    - Expertise in electric resource planning and resource acquisition, power purchase agreements, transmission issues, ratemaking, energy efficiency law and policy; legislative affairs and strategy, as well as public policy;
  - Federal Energy Regulatory Commission practice including transmission development and FERC Order 888 et. al., open access and transmission issues, transmission interconnection and LGIP; hydroelectric facility licensing and exemptions; Public Utilities Regulatory Policy Act issues involving Qualified Facilities; and municipalization-related issues.
  - Endorsed as an expert witness in resource planning in Georgia and Alabama.
  - Renewable energy project development/corporate matters, including: land lease/purchases, land use planning, transmission interconnection agreements, power purchase agreements, water rights, and mergers and acquisitions.
- Colorado Water Rights:
  - Adjudication of absolute and conditional water rights, changes of water rights, and augmentation plans as both applicant and opposition;
  - Purchase and sale of water rights, including title opinions;
  - Representation of owners of natural hot springs and geothermal water rights;
  - mutual irrigation ditch companies as general counsel, in easement disputes and crossing agreements, as well as corporate governance;
  - Representation of governmental and quasi-governmental entities, including strategic water planning.

  - Groundwater issues, including tributary and non-tributary rights.
  - Corporate matters, including entity organization and formation.
  - Endorsed as an expert witness in water matters before U.S. Bankruptcy Court.

- Real estate transactions, public land and environmental issues, including: negotiating agreements and permitting with U.S. Forest Service, BLM, and Bureau of Reclamation, experience in endangered species, water quality and easement rights.

Associate Attorney *Longmont, CO*
Bernard, Lyons, Gaddis, and Kahn, P.C. *01/05- 08/08*

- Colorado Water Rights: Practice in all aspects of water resources in Colorado. Water rights litigation, transactions, real property and water disputes. Adjudication of tributary and nontributary water rights and plans for augmentation, changes and exchanges. Work with numerous ditch companies, private users and governmental entities in a specialized water practice.
- Energy: PUC regulatory practice, including policy work, corporate matters, real estate/easement matters, wind, solar and energy efficiency.
- Real estate, with a focus on easement agreements and disputes; Corporate governance; transactions and contracts.

Staff Attorney - Energy *Denver, CO*
Environment Colorado *01/04-12/04*

- Lead counsel for successful defense of ballot initiative certification for Amendment 37 (Renewable Energy Standard) before the Colorado Supreme Court. Representation, public speaking (including debates), press outreach, fundraising for successful renewable energy standard ballot initiative in Colorado (first such public referendum in the U.S.).
- Lead counsel for PUC resource planning proceedings and comprehensive settlement negotiations with Public Service Company of Colorado.

United States Department of Justice Wildlife and Natural Resources Division Denver, CO
Interstate water litigation section *9/02- 1/03*

EDUCATION

University of Colorado School of Law, Boulder JD 5/2003
- Associate Editor, Colorado Journal of International Environmental Law and Policy
- President, Environmental Law Society
- New Law Building Design Committee (head of Green Building Committee)
- Bernard Seeman Scholarship (2000)

University of Michigan, Ann Arbor BA Political Science 5/1997
- Class honors (1996, 1997)
- Writing Excellence Recognition (9/1993)

London School of Economics and Political Science London, UK 1996

PROFESSIONAL AFFILIATIONS

- RMIAN – pro bono immigration assistance, 2016 - present
- Acequia Assistance project, University of Colorado School of Law, Mentor, 2018 - present
- Board of Advisors – Energy Innovation Center at Getches-Wilkinson Natural Resources, Energy and the Environment at Colorado School of Law.
- Colorado Water Congress – 2015 Chair of Professional Outreach Committee
- Colorado Water Leaders Program - Colorado Foundation for Water Education (2010)
- Pro bono attorney- Boulder County Legal Services, serving Spanish speaking clients.
- Chair, Natural Resources Sect. of the Boulder County Bar Assoc. (BCBA) 2006 – 2008

SELECTED PUBLICATIONS

- with John Wilson, Mike O'Boyle and Ron Lehr, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, Energy Innovation and the Southern Alliance for Clean Energy (April 2020).
- with Gabriella Stockmayer and KC Cunilio, *Electric Vehicles: Plugging into Colorado Regulation*, Colorado Lawyer (February 2020).
- *Electric Vehicles: Rolling Over Barriers and Merging with Regulation,* William and Mary Environmental Law and Policy Review, Vol. 40, No. 2 (March 2016).
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- with Jeffrey J. Kahn, *Current Issues with Changes of Water Rights Involving Shares of Mutual Ditch Companies*, in DITCH COMPANY HANDBOOK , Ditch and Reservoir Company Alliance (September 2007).
- *Against the Wind: Implementing Renewable Energy in Colorado*, Boulder County Bar Newsletter (May 2006).
- with Jeffrey J. Kahn, *Ditch Rights: The Law of Irrigation Easements and Rights of Way*, in COLORADO WATER LAW BENCH BOOK, Colorado Bar Association (2006).
- Comment, *The Murky Sea over the Magnificent Whale,* Colo. Journal Int. Env. L. Policy 2002 Yearbook (Summer 2003).
- Note, *The Global Light: Lessons for US Solar Policy*, 14 Colo. Journal Int. Env. L. Policy 301 (Spring 2003).

EXHIBIT MDD-2

Docket No. 22-11032
Interwest Energy Alliance
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MAKING THE MOST OF THE POWER PLANT MARKET: BEST PRACTICES FOR ALL-SOURCE ELECTRIC GENERATION PROCUREMENT

BY JOHN D. WILSON, [1] MIKE O'BOYLE,[2] RON LEHR, [3] AND MARK DETSKY[4] ● APRIL 2020

It is a golden age for power plant procurement. Utilities are paying less to acquire new power plants, whether they are powered by the sun, wind, water, fossil fuels, or operate as storage facilities. The global market to supply utilities with power plants is by any measure competitive.

And yet, market competition has surprised utility executives and generated heavy media attention with unexpectedly inexpensive and diversified responses to utility all-source procurements. A Colorado utility called the low solar and wind prices "shocking," but why are utility executives surprised by all-source procurement outcomes? More importantly, how can other utilities replicate these results?

All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market. Most vertically integrated utilities either voluntarily, or are required by regulators, to conduct competitive procurement through requests for proposals (RFPs) as part of the process selecting adequate generation resources. In an RFP, the utility describes the resources it wishes to procure, and may also offer self-build options to compete against market offers.

About half of the United States' utility sector operates in organized regional wholesale markets. In most utilities that operate in two of these markets, the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), and in the other half of the sector that does not participate in markets, vertically integrated utilities retain market power. State franchises for such utilities grant vertically integrated utilities rights and responsibilities, including exclusive service territory and an obligation to serve all customers. These utilities typically control the bulk

[1] Southern Alliance for Clean Energy https://cleanenergy.org/ and Resource Insight, Inc. http://resourceinsight.com/

[2] Energy Innovation https://energyinnovation.org/

[3] Energy Innovation https://energyinnovation.org/

[4] Dietze and Davis, P.C. http://dietzedavis.com/

of transmission assets in their service areas, allowing them to discriminate against competitive generation that would challenge the asset values of utility owned generation. These vertically integrated utilities are not only *monopolies* - sole sellers of power to customers - but they are also *monopsonies* - the single buyers of wholesale power within their service territories.

Vertically integrated utilities thus have market power: As sole buyers, they have control over inputs to and methods for conducting resource planning, as well as methods and assumptions used to evaluate bids received in competitive procurement processes. With the acquiescence of their regulators, these utilities can:

- Control information and impose biases on procurement processes, which can discourage or disfavor otherwise competitive procurement opportunities
- Exercise arbitrary or unfair decision making, which may result in competitive projects being rejected or saddled with unreasonable costs or delays
- Impose terms and conditions that may result in sellers having to accept below-market prices or onerous contract requirements in order to remain active in the market

When these practices occur, utilities may retain or procure uneconomic resources. As both monopolies and monopsonies, vertically integrated utilities are financially incentivized to seek opportunities that invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement.

At the time of this report's writing, many utilities are engaging in a rush to acquire new natural gas-fired capacity and clinging onto coal-fired generation when substantial costs and environmental impacts could be avoided by embracing clean alternatives. Utilities' preferences for gas-fueled generation may be at odds with economics, but it is not surprising. Preference for gas-fueled plants may be related to financial bias towards over-procurement of capacity and self-built generation, as well as an organizational culture and rate design that favors gas-fueled generation.

In order to better understand how regulators currently address these utility market power issues, we evaluated four cases of resource procurement by vertically integrated utilities: Xcel Colorado, Georgia Power, Public Service Company of New Mexico (PNM), and Minnesota Power. We also include brief comments on six other relevant cases.

Our case studies suggest that many vertically integrated utilities have adopted or are moving towards adopting all-source procurement processes.[5] They illustrate that utilities procure resources through all-source, comprehensive single-source, or restricted single-source RFPs. In contrast to an all-source procurement, in comprehensive and restricted single-source

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[5] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

procurements, the resource mix is determined in a prior phase and the utility conducts resource-specific procurements for each resource to meet the identified need or needs.

We recommend regulators adopt or revisit five best practices to run an all-source procurement process, and we describe a model bid evaluation process. These recommendations closely follow Xcel Colorado's approach, which has most successfully motivated both the utility as well as potential bidders to engage in a serious, vigorous competitive market process.

1. **Regulators should use the resource planning process to determine the technology-neutral procurement need.** Most all-source procurements were initiated without regulatory review and approval of the need. We recommend that Commissions use resource planning proceedings to make an explicit determination of need – but define that need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. This approach offers advantages over a specific, numeric capacity target and technology specification.
2. **Regulators should require utilities to conduct a competitive, all-source procurement process, with robust bid evaluation.** Four of our case studies (Xcel Colorado, PNM, Northern Indiana Public Service Company, and El Paso Electric) demonstrated that the market for generation projects can provide robust responses to all-source RFPs. These utilities' system planning models appear to be capable of simultaneously evaluating multiple technologies against each other. The optimum mix of solar, wind, storage, and gas resources is more effectively selected based on actual bids, rather than in a generic evaluation prior to issuing single-source RFPs.
3. **Regulators should conduct advance review and approval of procurement assumptions and terms.** Even though the majority of all-source procurements were initiated without regulatory review and approval, our study suggests that Colorado's practice of a full regulatory review process in advance of procurement is best. After-the-fact review creates a number of problems. Out of all the case studies, Xcel Colorado best demonstrates how utility regulators can proactively ensure that resource procurement follows from utility planning.
4. **Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding.** Most resource procurement practices we reviewed appeared to include regulatory requirements or utility codes of conduct that restrict information sharing with utility affiliated firms that might participate in the procurement. However, examples of bias toward self-build projects remain. An all-source procurement creates opportunities for large, self-built gas plants to compete against independently developed renewable or storage plants. Regulators should renew procedures that define appropriate utility participation when utility ownership is contemplated, considering that more complex bid evaluation processes can create additional opportunities for bias.
5. **Regulators should revisit rules for fairness, objectivity, and efficiency.** Considering new challenges presented by more diverse, complex, and competitive power generation markets, it is also worth revisiting regulatory practices that provide for fair, objective, and

efficient procurement processes. Public Utility Commissions (PUCs) generally require the use of an independent evaluator. Nonetheless, we observed opportunities for utility leverage in their control over contract terms, use of confidentiality to precluding parties from review, and submitting recommendations on tight timeframes. We also saw limited transparency regarding the results of the procurements."

TABLE OF CONTENTS

INTRODUCTION

It is a golden age for power plant procurement. By any measure, utilities are paying less for power plants whether they are powered by the sun, wind, water, or fossil fuels. Prices for battery storage are dropping fast. Developers and supply chains are diversified. There is ample public information about technology pricing and performance. The global market for power plants is by any measure competitive.

And yet, market competition has surprised utility executives and generated heavy media attention with unexpectedly inexpensive and diversified responses to utility all-source procurements. A Colorado utility called their recent low solar and wind prices "shocking." And an Indiana utility executive was surprised that wind and solar were "significantly less expensive than new gas-fired generation." Why were these two all-source procurement outcomes so surprising? More importantly, how can other utilities replicate these results?

All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market. Procurement practices for any electric utility are important. Considering the market power that vertically integrated electric utilities have, this paper is focused on how regulators of these utilities can update rules and practices to enable effective all-source procurements.

Access to the power plant development market occurs under market rules set by a regulator and through business practices set by utilities. A less competitive market enhances utilities' opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement. Greater openness to competition can take advantage of rapidly declining prices for clean energy technologies and innovative new use-cases from third-party developers, even within a regulated monopoly marketplace.

Most vertically integrated utilities are either required by regulators or voluntarily conduct competitive procurement through RFPs as part of their process for ensuring adequate generation resources. In RFPs, utilities describe resources they wish to procure, and may also offer self-build options to compete against market offers. Generally, utility procurements follow many recommendations outlined in a 2008 National Association of Regulatory Utility Commissioners (NARUC) report on competitive procurement.[i] Yet today's market is more diverse, complex and competitive than it was at that point in time.

Rules that may have been designed for single-source competitive procurements can disadvantage or even exclude cost-effective renewable energy, storage, and energy efficiency resources from utilities' resource procurements. Vertically integrated utilities, with acquiescence of their regulators, can:

1. Control information and impose biases on procurement processes, which can discourage or disfavor otherwise competitive procurement opportunities

2. Exercise arbitrary or unfair decision making, which may result in competitive projects being rejected or saddled with unreasonable costs or delays
3. Impose terms and conditions that may result in sellers having to accept below-market prices or accept onerous contract requirements in order to remain active in the market

When these practices occur, utilities may retain or procure uneconomic resources.

Utilities have control over inputs to and methods for conducting resource planning, and if regulators allow it, can use that control to their advantage.[6] Prevailing regulatory practices give utilities little financial incentive to pursue technologies (such as weather-dependent wind and solar) that force them to change their operating methods or accept lower levels of investment, even where ratepayers and the public interest could benefit.

Arguably, these are among the potential problems that organized competitive wholesale markets are intended to solve. Market rules established by regional transmission organizations (RTOs or ISOs) establish more transparent processes for new generation resources to participate in markets.

Yet roughly half of U.S. electricity load is served by vertically integrated utilities: One-third in traditional bilateral wholesale markets and one-fifth with access to competitive wholesale markets in the MISO and SPP regions[7]. Few regulators of vertically integrated utilities have revisited competitive procurement rules to address these increasingly diverse, complex and competitive markets. Accordingly, we have developed five best practices that regulators should use to update their competitive procurement rules.

1. Regulators should use the resource planning process to determine the technology-neutral procurement need
2. Regulators should require utilities to conduct a competitive, all-source procurement process, with robust bid evaluation
3. Regulators should conduct advance review and approval of procurement assumptions and terms
4. Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding
5. Regulators should revisit rules for fairness, objectivity, and efficiency

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[6] As noted in the executive summary, the scope of this paper does not extend to rules and practices related to inclusion of demand-side resources in resource planning. Colorado, for example, requires that utility resource plans include demand-side resources. There is also a need for many regulators to update practices to more optimally tap the increasingly sophisticated market for demand-side resources.

[7] Our simple metric identifies utilities that are regulated by states, rather than organized markets, when making resource procurement decisions. One recent review of multistate regional transmission organizations noted that, "In SPP and MISO, states have more input in resource adequacy decisions." Jennifer Chen and Gabrielle Murnan, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations*, Nicholas Institute for Environmental Policy Solutions, Duke University, NI PB 19-03 (March 2019), p. 15.

For vertically integrated utilities, especially in traditional bilateral-only wholesale markets, best practices for cost-effective procurement of power plants are modeled in Colorado.

COLORADO EFFECTIVELY ENGAGES THE MARKET

In 2018, the Colorado PUC captured the electric utility industry's attention with a low-cost, high-renewables portfolio of generation plants submitted as a multi-party settlement advanced by Xcel Energy in Colorado. Xcel Colorado (also known as Public Service Company of Colorado) operates the state's largest investor-owned utility and serves approximately 65 percent of energy load in the state. With wind and solar costs dropping rapidly, Colorado structured a workable, all-source competitive procurement process that provided unrestricted access to current market prices for available resources.

Xcel Colorado's most recent procurement, referred to as the Clean Energy Plan, included a portfolio of wind, solar, battery storage, and gas turbine resources to replace two coal plants. A total of 2,458 megawatts (MW) of nameplate resources were procured, resulting in 1,100 MW of firm capacity replacing 660 MW of coal plants. Other than the relatively small amount of gas turbine resources, the Clean Energy Plan represents a real-world example of what the Rocky Mountain Institute (RMI) has described as a *clean energy portfolio*: a mix of technologies that, together, can provide the same services as a thermal power plant,[ii] though RMI's framework would expand Xcel's approach to include strategic demand reductions from efficiency and demand response.

The competitiveness of this market example resulting in a clean energy portfolio is demonstrated by what the utility called "shockingly" low wind and solar prices – *median* bid prices of $18 per MWh for wind, $30 per MWh for solar, as shown in Table 1.[8] Wind and solar coupled with storage were marginally higher, but remarkably affordable,[9] and more than four hundred bids were submitted – both good metrics for judging a workably competitive process. Getting those competitive results requires concentrated attention from regulators, utilities, and stakeholders.

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[8] These prices include federal tax credits for wind and solar.

[9] Stand-alone storage costs are difficult to analyze based on the Xcel Colorado report to the PUC, since amounts of storage bid are not documented.

Table 1: Resource Prices in the 2018 Xcel Colorado Clean Energy Plan

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Source: Xcel Colorado, *2016 Electric Resource Plan: 2017 All Source Solicitation 30-Day Report*, COPUC Proceeding No. 16A-0396E (December 28, 2017).

Although not yet public, ultimate costs of the wind and solar projects are likely to be below median bid prices. These low costs mean that Xcel Colorado consumers' long-term generation costs will be lower and less risky as the company pursues its "steel for fuel" business model and climate mitigation goals.[iii]

It is also worth noting that Xcel Colorado is allowed to own projects that result from and to participate in its own RFPs.[iv] Subject to PUC discretion, Colorado utilities may target 50 percent utility ownership.

Much of the credit for this market-driven outcome can be given to Colorado's competitive resource acquisition model. Colorado regulators require planning and bidding, encourage early coal retirements and clean replacements, and solicit stakeholder support. The remarkable results are a credit to Colorado policymakers and to Xcel's managers and employees.[10]

UTILITY PLANNING AND PROCUREMENT CONCEPTS

In order to understand how Colorado's regulation of the generation market differs from some other state regulatory approaches, it is important to understand integrated resource planning and the system planning models used by utilities.

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[10] Credit has to be shared with the renewable energy industry, wind and solar developers, and firms that provide financial backing for renewables projects. Their growing sophistication and business acumen deserve mention.

INTEGRATED RESOURCE PLANNING

In two-thirds of states, procurement processes are linked to a regulated planning process, often called integrated resource plans (IRP). In these proceedings, utilities propose, and their regulators consider long-term power generation and demand side needs. [11, v] Future demands are projected and resources to meet them are considered. These IRPs are intended to inform utility investment decisions and allow regulators and the public to understand relative economics of different approaches, as well as operational and reliability tradeoffs associated with different resource mixes.

In states with traditional, or partially restructured, bilateral wholesale markets,[12] IRPs typically lead to discrete resource approvals through a certificate of public convenience and necessity (CPCN). Often, regulators require utilities to issue an RFP as part of that process. Regulators practice widely varying levels of review of IRPs. Some states, such as Colorado, require the IRP to be approved prior to proceeding to an RFP. In other states, the IRP review process may not include specific approvals – or, the submission of an IRP may be simply acknowledged or accepted, without leading to meaningful regulatory action.

Where regulators require the IRP to be reviewed prior to an RFP, utilities and regulators may proceed in a logical order, with regulators approving the need for new resources in the IRP, followed by the RFP, and leading to the CPCN. An idealized sequence is provided in Figure 1. However, some states, such as Florida, allow RFPs to be conducted by utilities first, with IRPs being submitted as part of CPCN process.

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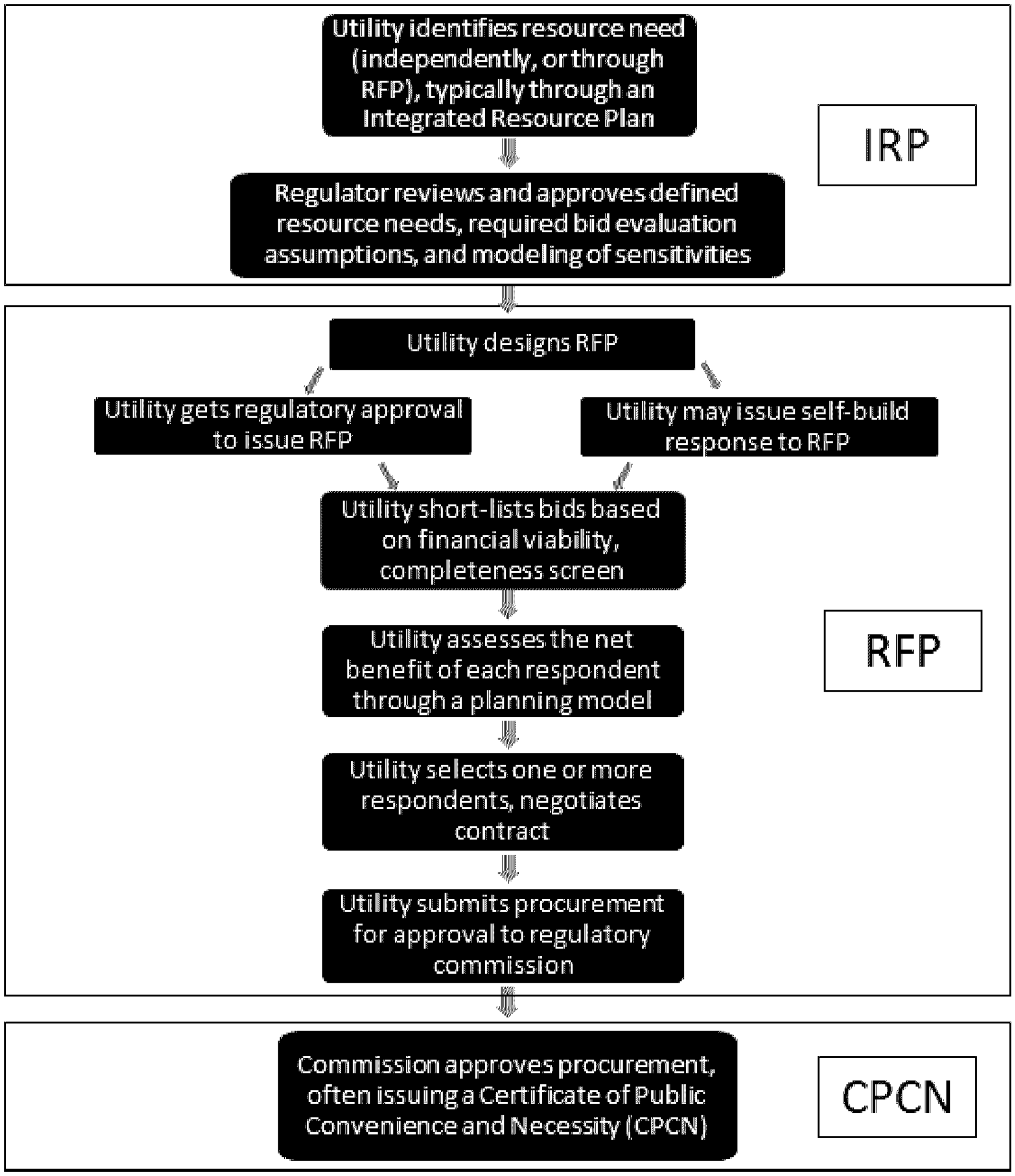
[11] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

[12] If the state policy allows retail choice within organized competitive wholesale markets, then any required resource planning process would inform a market procurement to supply customers who remain on the default service (if they have not elected a retail electric provider). Such procurements are not within the scope of this paper.

*Figure 1: Illustrative sequencing of utility planning and procurement**



*This represents an idealized sequence - some or all steps may not occur, potentially reducing regulatory oversight opportunities.

SYSTEM PLANNING MODELS

Utilities use complex planning models to evaluate cost-effectiveness of current and prospective generation resources. Often, utilities use a capacity expansion model to evaluate which resource choices to invest in to meet customer requirements.[vi] For example, if a utility forecasts that future demand will exceed its resources by 1,000 MW in a given year, the capacity expansion model will suggest that the resources should be, for example, some mix of solar, wind, gas turbine, or combined cycle plants based on the plants' relative economics and on forecasted customer energy demand.

Utilities often identify several capacity plan options, and then screen those options using a more detailed production cost model, which simulates how generation and market supplies will operate on an hourly basis. These models are generally licensed for use by utilities from vendors and often come with significant restrictions on access for regulators and other parties that may wish to inspect the utility's modeling practices.

System planning models are driven by complex algorithms which vary from vendor to vendor and by necessity, simplify real-world operating practices. For example, software may be configured to have a "must run" requirement for a power plant in a critical location, even though system operators may have other options to maintain system reliability. Also, IRPs may assume a level of energy efficiency program impacts, when it is possible to establish energy efficiency program levels by optimizing in the system planning model.[vii]

More recently, system planning models have struggled to accurately model battery storage, particularly if storage resources will be used to provide a mix of short- and long-term grid services. The Washington State Utilities and Transportation Commission recently noted that "traditional hourly IRP models are becoming increasingly inadequate," and urged a transition to sub-hourly models.[viii] The Commission also noted that IRP models remain unable to consider the distribution and transmission benefits of resources.

Furthermore, utilities' modeling practices can have a significant impact on modeling outcomes. Utilities may place constraints on certain resources that implicitly express utility preferences. These constraints are based on utilities' assumptions about resource capabilities and costs. Detailed analysis of how utilities use these models, employ current and outdated information, correct and incorrect assumptions, and adjust model variables is an extremely resource-intensive process. Regulators and other stakeholders who wish to review those decisions can be at a substantial disadvantage relative to utilities.

CAPACITY CREDIT

System planning models are typically designed to optimize resources to achieve a resource adequacy target (enough capacity to meet demand, even with generation outages). In some models, thermal generation resources are assumed to deliver their full nameplate capacity at the system's peak, regardless of actual past performance. Other models partially or fully consider significant risks of outages. But in all models, variable energy resources (solar and wind) are assumed to deliver less than nameplate capacity at system peak. To recognize these operating issues, system planning models will assign a capacity credit to resources, which is the "percentage of a generating technology's nameplate capacity that can be counted toward meeting resource adequacy requirements."[ix]

Ideally, system planning models will rely on probabilistic methods to calculate capacity credits of solar, wind, and traditional resources, and are increasingly developing these methods for energy storage resources.[x] Effective load carrying capacity (ELCC) and load duration curve (LDC) are a few methods used to measure capacity credit.[xi] If a utility uses a method that assigns an unreasonably low capacity credit to a resource, then system planning models will evaluate that resource as contributing less to resource adequacy than is merited.

Not only is it possible to assign an unreasonably low capacity credit to a single resource, but system planning models can also undervalue combinations of resources. The combination of solar and storage, for example, create “diversity benefits” in that their combined capacity credit is greater than the sum of their individual values.[xii]

DOMINANCE OF NATURAL GAS AND SOURCES OF BIAS IN UTILITY RESOURCE PROCURMENT

Colorado’s procurement is notable for its relatively low portion of gas-fueled generation. By contrast, even though some forecasts suggest wind and solar power development will roughly equal gas plant development over the next three decades, these national forecasts suggest that gas-fueled generation will continue to dominate.[xiii] This is particularly true for vertically integrated utilities. For example, as shown in Table 2, gas-fueled plants are forecast to be over half of all new generation in the Southeast, while solar power will represent about a third of new generation brought online between 2018 and 2025.[13]

Table 2: Forecast Power Development, Southeast Utilities, 2018-25

	New Capacity	Annual Generation	Generation Share
Gas	21 GW	75 TWh	53 %
Solar	20 GW	45 TWh	31 %
Nuclear	2.2 GW	17 TWh	12 %
Wind	0.3 GW	1 TWh	1 %
Other	1.7 GW	4 TWh	3 %

Preference for gas-fueled power plants is at odds with economics of power plant development, which in 2019 clearly favors renewable energy in terms of cost.

[13] The Southern Alliance for Clean Energy tracks utility integrated resource plans, public announcements of power plant development, and other similar sources to construct the forecast relied upon here. The Southeast includes non-RTO utilities serving customers in Alabama, Florida, Georgia, South Carolina, and parts of Kentucky, Mississippi, and North Carolina. Consistent with prevailing utility practice in the region, where a capacity need is not explicitly identified as gas generation, gas generation is generally assumed.

- For 2018, Lawrence Berkeley National Laboratory (LBNL) reports the levelized cost of energy (LCOE) for wind power averaged $36 per megawatt-hour (MWh), with subsidies and project financing terms driving contract prices down below $20/MWh.xiv
- For 2018, LBNL reports the median LCOE for utility-scale solar projects was $54/MWh, with subsidies and project financing terms driving average contract prices to $31/MWh, with some below $20/MWh."xv
- The most recent results from utility bidding processes, such as those discussed in the appendix, document renewable energy prices lower than those reported by LBNL.

In comparison, gas-fueled combined cycle plants have an average LCOE in the $44-68/MWh range.[xvi] Thus, wind and solar have a cost advantage of at least $8/MWh but more often at least $20/MWh. This cost advantage is one reason that RMI found "an optimized clean energy portfolio is more cost-effective and lower in risk" than gas-fueled power plants.[xvii]

The utility preferences for gas-fueled generation may be at odds with economics, but it is not surprising. Utilities own and operate numerous gas-fueled combined-cycle and combustion-turbine plants (about 1,900 units as of 2018[xviii]). Their preference for gas-fueled plants may be related to

- A financial bias towards over-procurement of capacity
- A financial bias towards self-built generation
- An organizational culture and rate design that favors gas-fueled generation.

That consumers bear the risk of fossil fuel costs through fuel cost rate riders in most states provides additional incentive for utilities to low-ball fuel cost projections and saddle consumers with risks that fuel costs will exceed projected values.

FINANCIAL BIAS TOWARDS OVER-PROCUREMENT OF CAPACITY

Financial theory suggests that utilities are incentivized to adopt practices leading toward over procurement of capacity (versus energy), which helps explain the current prevalence of natural gas in resource planning. The well-established Averch-Johnson effect demonstrates that a "firm has an incentive to acquire additional capital if the allowable rate of return exceeds the cost of capital."[xix] For example, one author has suggested that utilities that favor building large-scale nuclear plants "will deliver greater per-share stock price gains to their present investors than they would under any other resource strategy."[xx] In contrast, investments in energy efficiency programs or contracts with competitive renewable energy suppliers do not offer the utility opportunities to acquire and earn profits on additional capital. Utility practices that may lead to over-procurement of capacity include over-forecasting of peak load or arbitrarily limiting market imports in resource planning.

The concept of capacity is often defined bluntly in utility planning and procurement and system planning models demonstrate a tendency to plan for singular capacity events; sometimes evaluating just a single peak hour in a year. Yet it has been noted that "capacity is vague as to what energy or reliability service is being provided," and the North American Electric Reliability

Corporation has not identified capacity as an "Essential Reliability Service."[xxi] The practice of emphasizing capacity as a planning goal may be better aligned with utilities' financial interests than with the obligation to provide reliable service to their customers.

FINANCIAL BIAS TOWARDS SELF-BUILT GENERATION

Prevailing regulatory structures provide financial incentives for utilities building and owning new generation. State regulators grant utilities an authorized return on invested equity, so about half of typical gas plant investment costs are returned to shareholders. If a self-built plant has a larger investment scale, a lower risk, or a higher return than an alternative, such as energy efficiency or contracting for renewable energy, these investments will tend to drive utilities' stock prices up.[xxii]

Since regulators do not typically allow utilities to consider stock price impacts when making decisions, this would indirectly express bias within utility planning practices. For example, utilities may offer a pretext for excluding solar, wind, and storage resources from acquisition - perhaps by citing an unsubstantiated expectation that future price reductions warrant delay.

UTILITY CULTURAL BIAS AND RATE DESIGN FAVORS FUEL-BASED GENERATION

Utilities' organizational cultures may value existing operating practices designed around fuel-based resources, such as methods to control ramping or other grid management capabilities. Or utilities may simply default to the relative ease of substituting one fuel-based, dispatchable thermal resource for another. In an environment of relatively flat load growth,[xxiii] new generation needs are primarily driven by thermal generation retirements – aged coal and gas-fueled steam generation, as well as some nuclear plants. Gas-fueled thermal generation plants are traditional and well-understood, making operators comfortable with adding additional units.

This cultural bias can be bolstered behind prevailing rate design practices and least-cost planning arguments. Utilities may shift costs, risks, and potential liabilities (like coal ash disposal problems) onto customers by preferring resources with fuel prices to those, like solar and wind, without fuel price and related risks.

Gas fuel costs are automatically passed through directly to consumers using fuel adjustment rate riders, so utility customers bear costs and risks that gas prices will spike unpredictably, such as when weather impacts gas production and delivery. Yet utility planning practices may discount such risks by emphasizing the median forecasted fuel cost.[xxiv] By diminishing the utility's consideration of cost risks that are entirely borne by their customers, the utility's cultural bias towards fuel-based generation can be presented as a cost-saving preference.

Utilities' organizational cultures become meaningful in their system planning practices and they make critical assumptions and forecasts that determine whether their models reasonably consider economics of selecting alternatives such as wind, solar, storage, demand-side resources, imports, and exports. Utility planning staff may:

- Effectively exclude new or unfamiliar technologies from consideration by using outdated or unreasonable performance and cost assumptions, or by using software that lacks capability to properly model those technologies[xxv]
- Underestimate, arbitrarily cap, or ignore specific capabilities of resources such as wind, solar, storage, and demand-side resources[xxvi]
- Discount potential for regional markets or balancing authorities to provide reliability services[xxvii]
- Fail to consider whether existing power plants should be retired in favor of lower cost alternatives; instead assume that existing plants should remain in service until the end of their estimated useful lives[xxviii]

Beyond these specific model manipulations, utility planning itself may be organized around the existence of large, thermal generation plants. Transmission planning will tend to favor replacing coal plants with a similar resource in order to meet reliability standards, even though different transmission and generation approaches could also provide lower cost reliable service.

It is unclear whether corporate or regulatory environmental goals can overcome utilities' cultural biases. Some state laws or regulations have required that carbon reduction and other externalities be introduced into resource planning processes. In California, legislation has imposed a price on carbon,[xxix] prohibited regulated utilities from signing long-term contracts with coal-fired power plants,[xxx] and directed regulated utilities to procure clean energy resources in a "loading order."[xxxi] And in Colorado, recent state legislation directs the PUC to employ a federally determined social cost of carbon in planning.[xxxii] Of course, renewable portfolio standards requiring utilities to increase the share of renewable generation have been the strongest drivers of renewable energy deployment.[xxxiii]

In other states, some utilities have professed decarbonization goals without recommending regulatory action. Southern Company and Duke Energy, for example, have public "net zero" carbon decarbonization goals, yet both firms are investing heavily in gas-fueled generation and other natural gas infrastructure.[xxxiv] It seems that planning practices at many utilities have not shifted commensurate with the changing economics of resource planning.[14]

REGULATION OF UTILITY PROCUREMENT

Before 1978, vertically integrated utilities provided most of their own power by owning generation. Enactment of the Public Utility Regulatory Policies Act compelled utilities to purchase power from co-generators and small power producers. Then, the Energy Policy Act of 1992 further opened up regulated wholesale power markets.

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[14] Some utilities have initiated distribution resource planning to better align investments in the grid with distributed energy resources. It remains to be seen whether this will better align utility investments with resource planning economics, or whether new planning practices will result in additional barriers to alternative investment paths.

Vertically integrated utilities, however, retained market power as regulated monopolies exempt from federal antitrust laws. State franchises for such utilities grants them rights and responsibilities, including exclusive service territory and an obligation to serve all customers. State franchises may not require a vertically integrated monopoly to purchase power from a competitive market, unless states have established a competitive wholesale market subject to federal regulation.

Vertically integrated utilities are thus not only *monopolies* - sole sellers of power to customers - but they are also *monopsonies* - the single buyers of wholesale power within their service territory. Co-generators and independent power producers generally have a right to purchase access to utilities' transmission systems to access markets outside utilities' exclusive service territories, but this is a limited right that often comes with significant burdens and high costs.

Courts often define market power in terms of ability to control prices or exclude competition.[xxxv] Vertically integrated utilities, as both monopolies and monopsonies, often have substantial market power in their relevant generation markets due to monopolies on transmission services as well as the ability to exclude competitors from supplying electricity to utility customers. Utility regulators may maintain a singular focus on monopoly issues and overlook the market effects caused by regulated utilities' monopsony power.

Monopsony power gives vertically integrated utilities greater ability to act on monopolistic biases towards self-generation and over-procurement of generation. As sole (or dominant) buyers of power in a particular market, vertically integrated utilities have at least three tools they can use to constrain markets, shift risks to sellers, and force generation prices below long-term market rates.[15]

- Utilities' abilities to control information and impose biases on procurement processes can discourage or disfavor otherwise competitive procurement opportunities
- Utilities' arbitrary or unfair decision making may result in competitive projects being rejected or saddled with unreasonable costs or delays
- Utilities' abilities to impose terms and conditions may result in sellers having to accept below-market prices or onerous contract requirements in order to remain active in the market

The third tool, forcing sellers to accept below-market prices, might appear to help consumers by driving down power costs, but below-market prices are of course unsustainable. If utilities utilize all three tools, it may stifle competition enough to drive sellers to exit markets. Less competitive markets enhance utilities' opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement.

[15] These three tools are further explained in a companion paper, John D. Wilson, Ron Lehr, and Michael O'Boyle, *Monopsony Behavior in the Power Generation Market* (forthcoming).

Even though utility regulators are well acquainted with the tendencies of utilities to procure excessive resources, they tend to view these tendencies through the lens of monopoly behavior. For example, as sole power sellers, utilities can exercise pricing power to subsidize demand for their products at the expense of other providers. Perhaps because competitive procurement is a relatively new phenomenon (emerging over the past three or four decades), regulators have paid less attention to potentials for monopsony market power to result in over-procurement and less than competitive results.

RECOMMENDED BEST PRACTICES

Less competitive markets enhance utilities' opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement. To avoid procurements that are excessive (or even unnecessary), too costly, or not optimal, regulators of vertically integrated utilities need to address potential biases towards over-procurement, self-generation, and fuel-based generation. These biases are most likely to be advanced by utilities exercise market power through their ability to control information, engage in arbitrary or unfair decision making, and impose terms on sellers.

In order to better understand how regulators address these utility market power issues, we evaluated Xcel Colorado and three other significant cases of resource procurement by vertically integrated utilities (Georgia Power, PNM, and Minnesota Power). We also include brief comments on six other relevant cases. Due to the varying scope and characteristics of each case study, it was not possible to evaluate each procurement case across all characteristics. Detailed descriptions, especially of the four full evaluations, are provided in the appendix.

Our case studies suggest that many vertically integrated utilities have adopted or are moving towards adopting all-source procurement processes. [16] Our case studies illustrate that utilities procure resources through all-source, comprehensive single-source, or restricted single-source RFP processes, as summarized in Table 3.

- An all-source procurement is a unified resource acquisition process where requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market[17]
- A comprehensive single-source procurement uses a planning process to select amounts of different resource technologies to be procured; utilities conduct separate

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[16] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

[17] While this study is focused on case studies of supply-side resource procurements, demand-side and distributed resources could also be included in such procurements. Practices required to include those additional resource types are beyond the scope of this study but merit development.

procurements for each resource to meet the acquisition goal, each stated as a specific megawatt goal for a class of technology (e.g., solar or combined cycle gas).

- Single-source RFPs are generally developed internally and have no obvious linkages to consideration of other resource alternatives. (We did not identify any cases where a utility does not at least attempt an RFP before proceeding to self-build, but likely such practices continue) Utilities may be procuring other resource technologies, but those acquisition goals are developed in a separate process.

Numbers of bids received in each case study suggests that a regulatory requirement for use of an independent evaluator and significant staff scrutiny provide for a meaningful engagement of the market.

Table 3: Summary of RFPs Conducted in Case Studies (See Appendix for details)

Utility	RFP Type	Status	Bids
PNM	All-Source RFP	Pending 2020	735
Xcel Colorado	All-Source RFP	Approved 2018	417
Georgia Power	Comprehensive single-source RFPs	2015 Gas / 2017 RE Pending 2020	221 TBD
Minnesota Power	Comprehensive single-source RFPs	Approved 2018	115
NIPSCO	All-Source RFP	Announced 2018	90
El Paso Electric	All-Source RFP	Pending 2020	81
California	All-Source RFP	Various	(varied)
Florida	Single-source RFPs	Approved 2016	0 or few
Dominion Energy Virginia	Single-source RFP	Suspended 2019	n/a
Duke - North Carolina	Comprehensive single-source RFPs	Pending	n/a

These case studies support our recommendation that regulators adopt or revisit five best practices to run an all-source procurement process, and we describe a model bid evaluation process. These are based on Xcel Colorado's approach, which has most successfully motivated both the utility as well as potential bidders to engage in a serious, vigorous competitive market process.[xxxvi] Examples and evidence in support of these practices are mostly drawn from case studies in the Appendix, where assertions are explained, and citations are provided.

REGULATORS SHOULD USE THE RESOURCE PLANNING PROCESS TO DETERMINE THE TECHNOLOGY-NEUTRAL PROCUREMENT NEED.

Most all-source procurements were initiated without regulatory review and approval of the need. By "need," utilities conventionally specify a numeric capacity need, and often also specify technology eligibility, either by name or by restrictive performance standards. In contrast, the Colorado PUC makes an advance determination of need that, counter-intuitively, does not establish the specific capacity or technology to be procured.

Consistent with the process Colorado followed, we recommend that regulators use resource planning proceedings to make an explicit determination of need – but define that need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. Ideally, the determination of need would ensure that the procurement is open to any technology, and any siting location. This approach offers advantages over a specific, numeric capacity target and technology specification.

The Xcel Colorado case study shows how a need can be defined in terms of a load forecast and retirement of specific units without setting a specific, numeric capacity target or specifying a desired technology. In that case, the Colorado PUC approved two load-forecast scenarios, and several different generation scenarios, including both with and without retirement of two coal units. Xcel Colorado used the scenarios to construct several alternative portfolios of bids for the PUC to review. By using a flexible need, the Colorado PUC proactively ensures that resource procurement follows from utility planning.

When regulators lack a process for advance approval of the resource need,

- Parties are limited to challenging the utility's own determination of need after the RFP has been conducted, such as during a CPCN proceeding
- The utility's procurement may not consider retirements of existing power plants that would otherwise be out-competed by RFP bids
- The regulator may be presented with an up-or-down decision, rather than a range of options

While commissions may have good reasons for establishing a numeric capacity target for an RFP, our recommendation is that regulators establish need by approving the load forecast(s) and identifying which (if any) existing units should be considered for retirement. The resulting portfolio should satisfy the need created by the forecast and retirement options, with the utility procuring any amount of nameplate capacity of a mix of technologies based on cost-effectively meeting the need.

As in Colorado's process, the final determination of need can be made by the regulator when the utility presents alternative portfolios to the commission. In Colorado, the result is that the assessment of need and alternatives is largely absent from CPCN decisions.[xxxvii] If the commission determines need and reviews alternatives during the resource planning and all-source procurement steps, then a CPCN proceeding does not need to further consider these issues. As a result, the CPCN proceeding will be primarily related to reviewing project-specific financial or technical issues that would not have arisen in the previous proceedings. By determining need concurrent with reviewing the RFP portfolio results, the regulator can consider not only the need associated with a load forecast but may also take advantage of opportunities to replace existing plants and achieve a more cost-effective or cleaner resource mix.

Colorado's approach generated a robust, cost-effective portfolio, and the portfolio did not require a hearing for review due to extensive advance review. It also validated the recommendation to retire two coal units, which is a relatively new consideration in a procurement process. Where procurements fill a retirement need, they are generally in response to a firm retirement schedule. Otherwise, utilities usually assume that existing plants should remain in service until the end of their estimated useful lives.

Several of our case studies illustrate less robust approaches to need determination.

North Carolina: North Carolina utilities often simplify system planning models by making assumptions that existing generating units will continue to operate until they are fully depreciated. Recently, the North Carolina Utilities Commission ordered Duke Energy to remove such assumptions, and "model the continued operation of these plants under least cost principles."[xxxviii] However, this evaluation is confined to the IRP process for now, as the Commission has not ordered Duke to include existing plants in its procurement processes.

New Mexico: The New Mexico Public Regulation Commission (PRC) does not have a routine process for regulatory oversight of the need determination. Even though there was agreement between the utility and other parties about PNM's resource need, this success can be largely attributed to a one-time settlement related to environmental regulation issues. Neither the PNM or El Paso Electric case indicates that New Mexico regulators have a clear process for determining the need for generation procurement.

Virginia: An even less effective process occurred in Virginia, where the utility initiated an RFP based on an unapproved IRP after receiving a clear caution about its resource investment plans in the previous IRP.

Georgia: The Georgia Public Service Commission (PSC) has a clear process for approving resource needs in a resource planning proceeding, in advance of resource procurement. Over the past decade, the PSC developed a practice of multiple, single-source RFPs – together representing a relatively comprehensive procurement from the generation market. The potential for optimizing the mix through the bid evaluation process, rather than in Georgia Power's IRP, was challenged in the 2019 proceeding. Parties contested the insistence on "firm" capacity and lack of clarity on whether "firm" capacity included energy and how it could be supplied. These were not directly addressed in the PSC's order and instead were left to private negotiations between PSC staff and the utility.

California: Although California Public Utilities Commission policy has included all-source procurement for many years, the process has been constrained. A 2014 all-source procurement was mostly determined by localized capacity constraints which practically excluded many market options. The recent 3.3 gigawatt (GW) all-source procurement appears more promising, but does have a specific capacity target, in part because the procurement will serve a complicated mix of related entities.

REGULATORS SHOULD REQUIRE UTILITIES TO CONDUCT COMPETITIVE, ALL-SOURCE BIDDING PROCESSES, WITH ROBUST BID EVALUATION.

Many jurisdictions require or encourage utilities to acquire new resources through bidding. Often regulators rely on independent evaluators to provide assurance of fairness and rigor in the process.[18] But in some cases, utilities have simply built the next generation plant they have planned, either skipping or "winning" the bid process. This behavior is adequately explained by reference to utilities' financial incentives to increase capital spending, which should be recognized.[19] When the outcome of a bid process is neither predestined nor requiring an adversarial intervention to obtain a reasonable outcome, the bid process is likely to be competitive.

As discussed above, Xcel Colorado, PNM, NIPSCO and El Paso Electric all used all-source procurement processes, received large numbers of bids representing a wide range of technologies, development and ownership approaches, and competitively evaluated those bids within a system planning model to construct optimal portfolios. Bid evaluation was then fully explained in a regulatory proceeding. While few issues were raised after Xcel Colorado's review process because of thorough advance review, all four utilities had to fully explain their bid evaluation in some form of regulatory hearing.

In addition to restricting technology eligibility, single-source RFPs tend to leave meaningful issues unresolved and use a ranking process for bid evaluation. All-source procurements rely on market data and system planning models to make decisions about the scale and mix of resources. The equivalent decisions by utilities that use single-source procurements are made within those utilities' resource planning processes, which may or may not be subject to close regulatory oversight.

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[18] Notably, both Georgia Power and Xcel Colorado use Accion Group as the independent evaluator for their respective RFPs, but the procurement practices are significantly different.

[19] Regulators allow utilities to earn on equity investment as their major financial incentive. Not surprisingly, utilities, paid to invest, take whatever steps they can to make and justify these investments, including creating pre-determined bid processes that result in choosing the utility's own projects as bid winners. Steve Kihm et al., *Moving Toward Value In Utility Compensation: Part 1 - Revenue and Profit*, America's Power Plan (June 2015).

Insufficient oversight of bid evaluation practices may leave meaningful issues unresolved.

The case studies suggest that regulators do not exercise strong oversight of bid evaluation practices for most vertically integrated utilities. While the discussion above explains how the best approach is advance review, even during after-the-fact reviews the level of oversight is often insufficient to resolve meaningful technical or policy issues.

Utilities need this oversight because their behavior often aligns with their interests in exerting control over the "quantity procured, generation profile, project siting, and reliability" of resources that they acquire.[xxxix] This exertion of utility control can lead to utilities imposing biases on the procurement process, which can disfavor an otherwise competitive procurement - and, if utilities are allowed to exercise arbitrary or unfair decision making, otherwise beneficial projects can be rejected.

Colorado regulators provide the only example of strong, comprehensive oversight. The resource planning process includes a clear need determination, as well as review of draft requests for proposals, bid evaluation criteria, and proposed purchase agreements. Xcel Colorado's RFP was not challenged by intervenors on these issues. In contrast, the following examples highlight different types of gaps in oversight.

Georgia: Georgia Power's resource plan was challenged on its valuation of renewable energy and lack of clarity on whether "firm" capacity included energy and how it could be supplied. The assumptions and methods used in the planning process were also to be used during bid evaluation. Many issues raised in the Georgia Power case were not directly addressed in the PSC's order and instead were left to private negotiations between PSC staff and the utility. On the other hand, Georgia Power's RFP process does include close oversight of the bid evaluation process by PSC staff, including bid evaluation by both staff and the independent evaluator.

Minnesota: Intervenors criticized Minnesota Power's procurements for being rushed, including unrealistic requirements, disallowing otherwise qualified proposals due to a Federal Energy Regulatory Commission (FERC) ruling, negotiating for a single project, and using unreasonable and biased modeling assumptions and constraints, undervaluing clean alternatives. Although regulators expressed concerns about many of these issues, Minnesota Power's recommended projects were approved.

Bid evaluation practices vary from relying on models, to ranking based on costs.

Those vertically integrated utilities that have adopted or are moving towards adopting all-source procurement processes are also using their system planning models to create optimal portfolios and select winning bids. Xcel Colorado, PNM, NIPSCO, and El Paso Electric all demonstrate this practice.

It is difficult to imagine how an all-source procurement might be conducted without using system planning models to evaluate all bids together. This is the key distinction between all-source procurement utilities and utilities that use comprehensive single-source procurement or single-source RFP to acquire resources. In general, utilities that do not use all-source procurements simply rank qualified bids based on cost or, somewhat better, net benefits.[20]

For example, Minnesota Power used a net benefits approach that compares costs with a calculated estimate of project benefits. Yet even though Minnesota Power calculated project benefits of its preferred gas plant using its system planning model, it did so in comparison to generic resources, not actual bids it had received in its single-source RFPs. Only after selecting and evaluating projects did Minnesota Power combine winning projects from all its RFPs together in a portfolio analysis.

Georgia Power also uses a net benefits approach, the scope of which has led to several technical challenges to its evaluation method. While many of these challenges continue due to the PSC's deferral to its staff, some are a result of the utility's preference for ranking bids based on one-by-one evaluation rather than a comprehensive system planning model driven selection.

Restricted single-source RFPs do even less comparative analysis by basing procurement on an internal need assessment. The IRP sets the allocation between resource technologies, meaning that the critical decision about which resources are invested in depends on utilities' assumptions regarding cost and performance, rather than the results of the RFP. All too often, these RFPs result in few or no independent alternatives to a self-build proposal and can never result in a meaningful alternative to utilities' IRP modeling analysis.

REGULATORS SHOULD CONDUCT ADVANCE REVIEW AND APPROVAL OF PROCUREMENT ASSUMPTIONS AND TERMS.

Colorado's practice of reviewing all aspects of the procurement process in advance of the RFP is relatively unusual. Most of the RFP processes we reviewed did not require advance review and approval of the assumptions, bid evaluation process, and key bid documents, including contract terms and conditions. This results in a number of problems that may not be resolved due to the focus on making an up-or-down decision on the final procurement request.

In a better approach, the Colorado PUC uses its Phase 1 process to approve required bid evaluation assumptions and modeling of sensitivities, and relevant policy decisions such as carbon cost criteria. Xcel Colorado is held accountable for quality of its planning efforts prior to an RFP being issued. After the utility bid report is submitted to the Colorado PUC, hearings are generally not required to obtain approval.

In addition to a less contentious and ultimately smoother process, the advance approval approach used in Colorado also ensures that potential bidders receive adequate information about what, where and when the utility really needs to acquire additional resources - including capacity and energy, and potentially ancillary services.

[20] Another method is to use a scoring rubric that includes multiple metrics. This approach was not used by any of the utilities in our case studies.

Most all-source RFP processes reviewed do not require advance review and approval.

Colorado's Electric Resource Planning process uses a two-phase approach to provide this explicit link. The first phase considers the utility's planning study findings, and results determine objectives of an all-source procurement and how bids will be evaluated. This first phase influences, but does not constrain, technology choices in the all-source RFP process. The second phase considers results of all-source procurement. Remarkably, of all-source procurement processes we reviewed, Xcel Colorado's may be the only one that did not require a hearing for regulatory approval of RFP results.

The other three all-source procurements at PNM, NIPSCO, and El Paso Electric, were initiated by utilities without advance regulatory review of planning conclusions or RFP materials. In the cases of PNM and NIPSCO, there were prior utility filings and proceedings that informed procurement process, but specific terms of all-source procurement were not reviewed in advance.

Some single-source RFP procurements generally exhibit greater advance oversight of assumptions used for bid evaluation and terms of the RFP. The Georgia PSC requires approval of all bid evaluation practices and documents prior to final release. Although Minnesota Power procurement derived from the preceding IRP, the final procurement arguably departed from the Minnesota PUC's order in key respects.

Problems that occur when regulators don't require advance review and approval

Regulators should conduct advance review because resource plans rely on models that in turn include assumptions and criteria that directly affect both resources procured and overall costs of resource acquisition. We see evidence that failure to conduct these advanced reviews enables utilities to control information and impose biases on procurement processes.

If advance review and approval doesn't occur, then regulators may review these key decisions when utilities present RFP results for certification of resource acquisitions. In our case studies, these after-the-fact reviews occurred in proceedings marked by substantial challenges to assumptions and criteria used to define need and evaluate bids, as well as contract terms. These after-the-fact reviews created at least five problems:

- Alternative resources being excluded from planning or procurement, or being effectively excluded by using outdated or unreasonable performance or cost assumptions
- A choice between accepting a potentially flawed procurement, or accepting delays and additional costs of re-doing RFPs
- Decisions on specific project portfolios often result in failure to set clear policy for future procurement practices
- Emerging technologies may be undervalued or excluded if new procurement practices are not developed
- RFPs themselves may be less competitive due to utilities withholding information from bidders

Furthermore, after-the-fact review may create more work for regulators, as shown in the following examples. Regulators may be concerned about the resources required to hold two or three proceedings. However, dealing with all the issues in a single proceeding may result in a more complex decision, which is either even more resource intensive, or results in issues being left unaddressed or unresolved.

Minnesota: Difficult choices between accepting a flawed procurement and ordering a re-do is illustrated in Minnesota. The Minnesota PUC explicitly refused to proactively approve Minnesota Power's procurement of a gas plant, but the utility proceeded to issue a gas plant RFP, thus excluding alternative resources from consideration beyond limited amounts in separate single-source procurements. When the PUC reviewed results of this gas plant RFP, neither it nor intervening parties were able to propose specific, credible alternatives other than issuing a new RFP. Thus, when a regulator feels compelled to focus on immediate needs for action, it may defer policy decisions to further consultations between the utility and its staff, and clear policy may not be set.

New Mexico: In the PNM case, the New Mexico PRC conducted an extensive after-the-fact review of both significant technical issues with the utility's system planning model as well as policy issues related to application of the recently enacted Energy Transition Act. Some of these same issues are being raised in ongoing El Paso Electric resource acquisition proceedings. Since the PRC enabled intervenors to address those issues using the utility's system planning models, viable alternative portfolios were suggested during an after-the-fact review - a very unusual situation. However, since no decision has been reached in the PNM case, it is unclear whether this after-the-fact review will enable the PRC to resolve technical and policy disputes without delaying contracts.

Georgia: Even if regulators explicitly approve the RFP process in advance, they may not rule on critical assumptions and criteria as part of that approval. For example, in Georgia, these decisions are handled during RFP review, and the PSC staff recommends their approval as part of the RFP solicitation's final review . However, while influenced by the PSC staff review, the methods, assumptions, and criteria for evaluating bids are primarily determined by Georgia Power and for the most part, disclosed to bidders only in "illustrative" format. Bidders can only view and contest project-related assumptions, and they cannot view or contest the system-related assumptions that affect evaluation of their bids.

A more general problem we observed across many of the case studies is that while utilities have generally acknowledged the value of grid services, those values may not be recognized for new technologies in the same way that they are taken for granted from gas-fueled generation. Or, if compensation terms are unclear, then bidders will need to build in pricing risk to include in their bid costs. In either case, failure to clearly articulate value of grid services for new technologies puts bids for those resources at a disadvantage. For example, bidders in the cases we studied have little or no indication of the value that vertically integrated utilities have for "flexible" and "quick start" generation resources, like energy storage or reciprocating engines. Additional steps are needed to capture value of multiple grid services that renewable and storage resources can provide.[xl]

REGULATORS SHOULD RENEW PROCEDURES TO ENSURE THAT UTILITY OWNERSHIP IS NOT AT ODDS WITH COMPETITIVE BIDDING.

Regulators often allow utilities to participate in their own RFPs, either directly or via an affiliate owned by the corporate holding company. They may also buy out developers using a "build-transfer" contract or, as in the case of Minnesota Power, take ownership stakes in the project. Most resource procurement practices we reviewed appeared to include regulatory requirements for utility codes of conduct that restricted information sharing with affiliates who might participate in procurements.

However, some examples of bias toward self-build project remain. An all-source procurement creates opportunities for large, self-built gas plants to compete against much smaller, independently developed renewable or storage plants. Or, more often, utilities may simply propose a single-source RFP that creates a favorable opportunity for their own self-build proposals. Regulators should renew those procedures, considering whether more complex bid evaluation processes will create additional opportunities for bias.

When utilities have the right to self-build, a competitive bid process provides utilities with concrete incentives to reduce costs, encourage technology development, and promote new business and financial approaches. Otherwise, the utility's bids will be uncompetitive. For example, in the case of El Paso Electric, the utility self-built 226 MW of the 370 MW procurement target, but also found it cost effective to exceed its target and procure 350-550 MW of market-supplied resources. One might speculate that El Paso Electric might simply have built a 370 MW peaker plant in the absence of an all-source procurement. Certainly, the NIPSCO comments cited above indicate a degree of surprise at results delivered by engaging the market.

In contrast, Florida's history of utilities selecting themselves as the winner of every RFP suggests that meaningful competition can be discouraged by an ineffective procurement process. Similarly, the suspended Dominion Energy Virginia RFP was accused of bias towards self-build projects. We did not review Florida or Virginia RFP proceedings comprehensively, so we do not suggest what specifically causes this lack of meaningful competition.

It is a responsibility of regulators to proactively address structural bias and prevent improper self-dealing by utilities. Regulators should not wait for independent power producers to invest in futile bids in the hope that their challenges to bid procedures will result in a commission-ordered remedies. The 2008 NARUC report on competitive procurement[xli] suggests that regulators use the following methods:

- Involvement of an independent monitor or evaluator
- Transparent assumptions and analysis in a procurement process
- Detailed information provided to potential bidders
- Utility codes of conduct to prohibit improper information sharing with utility affiliates

- Careful disclosure and review of "non-price" factors and attributes, particularly if they may advantage self-build or affiliate bids

Our recommended best practices build on those in the 2008 NARUC report, and we observed that they are often effectively applied within the context of current planning and procurement processes. However, the evidence of some degree of structural biases and improper self-dealing, as well as new challenges in all-source procurements, suggests that these best practices need renewed attention as regulators update rules and practices.

When regulators enforce requirements for utility codes of conduct that restrict information sharing with affiliates who might participate in the procurement, a fair process still gives the utilities opportunities to provide equity earnings. Opportunities for utilities to own new resources acquired through market procurements can allow them to avoid "hollowing out rate base" and maintain earnings per share for their investors.

REGULATORS SHOULD REVISIT RULES FOR FAIRNESS, OBJECTIVITY, AND EFFICIENCY.

Considering new challenges presented by more diverse, complex and competitive power generation markets, it is also worth revisiting NARUC's recommendation that procurement processes should be fair, objective, and efficient. As discussed above, regulators should revisit safeguards against preferential treatment of any offers, especially from regulated utilities or their affiliates. Regulators should also ensure that utilities do not engage in unfair, biased, or inefficient processes that result in developers seeing bids rejected, saddled with unreasonable costs or delays, or forced to accept contract terms that drive pricing to below-market levels.

To ensure that all-source procurement is conducted with fairness, objectivity, and efficiency, regulators should:

- Require use of an independent monitor or evaluator
- Require pre-approval of contract terms and directly monitor the utility's use of any remaining flexibility
- Provide for a process that affords all parties a reasonable opportunity to influence outcomes
- Establish methods to address unforeseen circumstances
- Establish reasonable protections for confidential information (not just deferring to the utility)

Most resource procurement practices we reviewed appeared to include regulatory requirements for an independent evaluator. We saw evidence that independent evaluators had adequate authority and impact in the Xcel Colorado, Minnesota Power, and Georgia Power cases. PNM used a third-party to assist in administering the RFP process, but it was not clear whether it was truly "independent."

We also saw evidence that many vertically integrated utilities retain a high degree of control over contract terms with potential resource developers. Contract terms are only reviewed after parties have negotiated power contracts for Minnesota Power, PNM, NIPSCO, El Paso Electric, Dominion Energy Virginia, Florida utilities, and Duke Energy in North Carolina. For example, Dominion Energy Virginia's contract terms were stated to be only available on a confidential basis and specified that proposed revisions "may" be considered. Furthermore, while Dominion claimed that battery storage technologies would be considered in the RFP, no contract terms were available. The Xcel Colorado and Georgia RFPs demonstrated a better approach where regulators reviewed and approved contract terms when authorizing final RFP documents.

We are not convinced that many regulators give all parties have a reasonable opportunity to influence outcomes, or that Commissions had established procedures for addressing unforeseen circumstances. Colorado provides bidders with clear rights and opportunities to review the bid-specific assumptions the utility has determined prior to bid evaluation. Other parties who may have a legitimate interest in the outcome of the procurement are also at a disadvantage when there is no opportunity to review aspects of the procurement process. For example, legislative requirements to consider carbon emissions in California and localized economic impacts of plant retirements in New Mexico present legitimate interests in verifying the fairness of bid evaluation practices. A utility's use of confidentiality to restrict review and make unilateral decisions can go as far as to leverage the process to obtain a preferred outcome.

Some commission practices allow utilities to leverage the process to obtain a preferred outcome.

Regulated procurement processes can result in less than optimal outcomes: Under the pressure of a thumbs up or down decision and using imprecise regulatory standards, commissioners and staff experts may feel pressure to render what might be termed "constructive" decisions. Under such pressure, regulators may overlook actions that resulted in bids being rejected, developers facing terms with unreasonable costs, delays, or onerous terms. If the utility advances its recommendation at a time when the need precludes consideration of otherwise cost-effective alternatives, this only exacerbates pressure on regulators.

- In Minnesota, commissioners may have revised their legal standards or shortcut evidentiary review in the interest of approving a gas-fueled power plant that had been discussed for several years. Rejection would have created very tight timelines for procurement.
- Also in Minnesota, the utility's handling of a FERC ruling that affected some bids raised questions that were not answered in the final order.
- In Georgia, IRP and RFP proceedings are almost always settled through bilateral negotiation between PSC staff and the utility followed by PSC approval. While some policy intervention by the PSC does occur in its final order, this practice results in fewer opportunities for other parties to influence outcomes than in states with more direct engagement by the PSC on critical practices.

Time pressures, unforeseen circumstances, development of customs, or practices that lead to negotiated deals are inevitable in the regulatory process. These tendencies should be checked by regulators in advance. For example, regulators can ensure that procurement processes are designed to create reasonable alternatives to the utility's preferred portfolio, and that a public interest standard is applied to selection among those alternatives.

Some utilities offer little transparency.

To demonstrate the impact of a fair, objective, and efficient procurement process, some utilities provide detailed bid reports. These reports include specific information on numbers of bids; average, median, or ranges of prices, and reasons for selecting bids. See, for example, summaries from Xcel Colorado (Table 1), and PNM (Table 5). Other utilities often do not report average, median, or ranges of bid prices publicly.

The lack of transparency makes it more difficult to resolve other issues. As discussed above, some key technical issues are often left unresolved by regulators, with the additional implication being that the utility's technical choices may be considered confidential. Furthermore, it is difficult for other parties to use confidential RFP results to question the utilities' modeling analyses and resulting allocation of resources among various technologies. The heavy use of confidentiality in most of RFP processes we reviewed limits opportunities for public evaluation of both IRP planning and RFP process effectiveness.

Furthermore, if public scrutiny does not lead to clear understanding of what generation resources the market is offering, then intervenors and staff are unable to respond with better options. This in turn can diminish policymakers' confidence in the cost-effectiveness of alternatives.

MODEL PROCESS FOR BID EVALUATION

a. After the commission has determined the need, or several need scenarios, the utility (or regulatory staff, as appropriate) should:

   i. Select an independent evaluator.

   ii. Revise and publish the RFP and model power purchase agreement (PPA) documents as permitted by the commission's order, with input from relevant parties and potential bidders. The utility may issue separate forms for renewable, hybrid (renewable with storage), and fully dispatchable generation. Renewable resources should be allowed to submit multi-part bids for must take, curtailable, and flexible contract options for the same generation project. The RFP should specify the methods for considering end effects if contracts are of differing lengths.

b. The utility should screen bids for minimum compliance. If necessary due to bid volume, similar projects may be ranked against each other and least competitive bids may be removed from consideration.

c. The utility should evaluate the bids using system planning models.

   i. All off-model adjustments to reflect resource-specific costs and benefits authorized by the commission should be made prior to input in models if possible.

   ii. The capacity expansion model should optimize among bids of all technologies to fill approved system energy needed during the resource acquisition period (e.g., through 2028). Capacity values for renewable and storage technologies should be used as assumptions in the capacity expansion model, and thermal technologies should include forced outage rates and other applicable constraints on capacity.[21]

   iii. The utility should use model results to create and compare multiple bid portfolios. Regulators may add specific objectives that should be satisfied by alternative optimized portfolios, and they may encourage portfolios based on sensitivity analyses to cost, load, or other uncertainties.

d. The utility should further study costs of top performing optimized portfolios using a production cost model to run sensitivities as approved by regulators. If there are concerns about reliability, utilities could also conduct resource adequacy studies on top performing optimized portfolios.

e.	Results of evaluations should be summarized in a report, with all model evaluation data made available for review by regulatory staff and qualified intervenors. The independent evaluator's report should be included.
f.	After soliciting comments on the bid evaluation report from parties, regulators should approve or modify a resource portfolio. If the Commission authorized multiple need scenarios, the decision should also explicitly identify the need scenario that it is relying upon.

CONCLUSIONS

With these suggestions in mind, utilities, regulators and consumers can all benefit from competitive processes that reveal the best resource options available in the market at the time. Xcel Colorado's recent bid results ratify the notion that these results can be accomplished, if the right planning procedures are followed, regulators regulate utility monopsony power in the public interest, and competitors are motivated by adequate information and transparent process to risk their capital by submitting many bids at low costs. These outcomes are not the work of a day or a week, but by paying attention to the lessons already learned, the pattern that works in Colorado can provide guidance toward a cleaner electric sector.

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[21] It may be appropriate to use seasonal capacity values and more sophisticated methods as they evolve.

APPENDIX

Table 4: Summary of RFPs Conducted in Case Studies

Utility	RFP Type	Status	Bids
PNM	All-Source RFP	Pending 2020	735
Xcel Colorado	All-Source RFP	Approved 2018	417
Georgia Power	Comprehensive single-source RFPs	2015 Gas / 2017 RE Pending 2020	221 TBD
Minnesota Power	Comprehensive single-source RFPs	Approved 2018	115
NIPSCO	All-Source RFP	Announced 2018	90
El Paso Electric	All-Source RFP	Pending 2020	81
Florida	Single-source RFPs	Approved 2016	0 or few
Dominion Energy Virginia	Single-source RFP	Suspended 2019	n/a
Duke - North Carolina	Comprehensive single-source RFPs	Pending	n/a

ALL-SOURCE RFP CASE STUDY: XCEL COLORADO DEMONSTRATES A PROVEN SOLUTION –

As discussed in the report, in 2018 the Colorado PUC approved Xcel Colorado's portfolio of wind, solar, battery storage, and gas turbine resources to replace two coal plants, referred to as the Clean Energy Plan. A total of 2,458 MW of nameplate resources were procured, resulting in 1,100 MW of firm capacity replacing 660 MW of coal plants.

The cost-effectiveness of the portfolio was driven by what the utility called "shockingly" low wind and solar prices -- *median* bid prices of $18 per MWh for wind, $30 per MWh for solar.[22] Wind and solar coupled with storage were marginally higher, but remarkably affordable.[23] Although not public, the ultimate cost of the wind and solar projects are likely to be below the median bid prices. Much of the credit for this market-driven outcome can be given to the Colorado competitive resource acquisition model.

[22] These prices include federal tax credits for wind and solar.

[23] Stand-alone storage costs are difficult to analyze based on the Xcel Colorado report to the PUC, since amounts of storage bid are not documented.

Colorado's Planning Process Creates the Market

Since 2004, Colorado's PUC has relied on a two-phase process motivating the utility and potential bidders to participate effectively in supplying a cost-effective mix of resources to serve Xcel Colorado's customers. Colorado utilities must submit an electricity resource plan ("ERP") every four years.

In Colorado, procurement policy shifted towards bidding for new resources in the wake of Xcel Colorado's rate case including about $1 billion in new costs for the Pawnee coal plant in the early 1980s. A billion dollars dropped into a rate case for a new power plant did not give the Colorado PUC or ratepayers time to consider options due to construction timelines, with insufficient notice to participate in decision making. The utility responded to these complaints by producing a hefty binder of planning information, inviting the PUC and interested parties to a single afternoon discussion about planning. Then, in 1989, Xcel Colorado's system was overwhelmed with the interest of nearly 1,000 MW of qualified facilities in response to avoided costs related to the Pawnee unit. In response, the Commission approved a moratorium on QF contracts.

Solutions began to emerge. One commissioner had been looking into bidding constructs that might be applied to the unique circumstances of a monopoly utility.[xlii] NARUC, through its Energy Conservation Committee, had developed "integrated resource planning" during the late 1980s based on a Nevada rule, developed by Jon Wellinghoff.

Drawing on these resources during the early 1990s, the Colorado PUC wrote the Colorado Electric Resource Planning (ERP) rules.[24] Each successive application of these rules has led to changes and improvements.[25] The current PUC is continuing to develop the Colorado planning rules to incorporate distribution planning, additional attention to transmission and market issues, and to conform its planning rules with recently legislated aggressive carbon reduction goals.[xliii]

The Colorado ERP proceeding occurs in two phases, planning and procurement, followed by a CPCN proceeding for utility-owned facilities. In the most recent proceeding, the entire process took about three years. The planning process took about one year, the all-source RFP took 16 months, and most of the CPCNs were issued within 14 months. This proceeding establishes the market rules by which Colorado's investor-owned utilities procure power.

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[24] The process began with a QF only solicitation that morphed into integrated resource planning starting in 1996.

[25] Colorado's ERP rules initially focused on RFPs for PURPA qualifying facilities, but the rules were revised to an all-source process beginning in 1996. Prior to competitive bidding, there had been consistent controversy over PURPA enforcement, resulting in a QF moratorium. Actual bidding in Colorado began after bidding rules were negotiated and then jointly proposed by Public Service Company of Colorado and the newly formed Colorado Independent Energy Association (CIEA). The Commission accepted those jointly proposed rules in 1991. However, the utility then balked at complying, and CIEA battled for a number of years to get the transparent bidding rules followed, and to have an independent evaluator included in the bidding process.

Colorado ERP Phase 1: Utility Planning

Generation procurement in Colorado begins with planning. In Phase 1 of the ERP proceeding, like many IRPs, the Commission reviews all planning related data and information. Phase 1 also includes review of the utility's draft request for proposals, bid evaluation criteria, and proposed power purchase agreements. Thus, the Colorado ERP process links planning and competitive bidding from the very beginning.

Xcel Colorado relies on capacity expansion and production cost modeling to arrive at an approved resource need, taking into consideration load forecasts, fuel costs, renewable integration (including costs and effective load carrying capacity), carbon cost, reserve margin, and other study results. Demand side management and distributed generation are also input to the ERP, as they determined in separate proceedings based on the PUC's view that markets for supply and demand side resources are not conveniently bid together. Like many IRPs, the PUC conducts hearings to review this determination of resource need, including definition of the capacity shortfall, required modeling of sensitivities, and other technical findings. However, unlike most IRP proceedings, in Phase 1, the Colorado PUC neither approves a utility's "base case" nor decides what technologies should fill a capacity need.

The Colorado PUC's 2017 determination of need is relatively unique. Instead of approving a "single MW estimate of resource need," the RFP was authorized to fill a range of different need scenarios, including the following.

- A zero-need scenario, which considered the possibility that Xcel Colorado would have a minimal need. Nevertheless, the PUC anticipated that the portfolio might include "wind resources (and perhaps solar resources) and would not preclude the potential acquisition of low-cost gas-fired resources."[xliv]
- A 450 MW need scenario, based on the demand forecast. (The PUC directed that a post-hearing load forecast be used for the most updated information.)
- An alternative scenario in excess of the calculated resource need that provides benefits to customers over the planning period.
- A "Clean Energy Plan" scenario, which increased the need to allow for the early retirement of two coal units.[xlv]

Thus, although the Phase I decision gave Xcel Colorado clear direction as to what needs to consider in its procurement process, it did not give advance approval of a specific amount or type of capacity resource.

In addition to the need determination, Colorado's Phase 1 review includes RFP documents, model contracts, modeling assumptions that will be used to conduct the all-source RFP bid evaluation, the process by which transmission costs are factored in to bids, the surplus capacity credit (how to handle bids that aren't perfectly matched to need), backfilling (how to compare bids of various length) and other procurement policy matters.[xlvi] Thus, the PUC's 2017 Phase 1 decision aligned the utility's identified resource needs, planning assumptions, and bid evaluation criteria in advance of Xcel Colorado's all-source RFP.

Colorado ERP Phase 2: Resource Procurement

In Colorado's Phase 2, the utility issues an all-source RFP. The 2016 Xcel Colorado RFP included three bidding forms for intermittent, dispatchable and semi-dispatchable resources. The use of three different bidding forms facilitated the initial screening process, in which bids are categorized by resource in order to be reviewed for minimum eligibility criteria. Initial screening also includes an economic screen, based on an "all-in" levelized energy cost ("LEC"), meaning all costs and benefits included.

Colorado Electric Resource Planning Rule

It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation). 4 CCR 723-3-3611(a)

From that initial review process, bidders are notified whether their projects will proceed to the modeling phase and, if so, the specific assumptions that will apply to their project, with opportunity for dispute within a limited time window. In 2016, 160 of 417 eligible bids received by Xcel Colorado were included in the system planning model analysis.[xlvii]

All bids that are forwarded to modeling are modeled together[26] under the assumptions approved in Phase 1. The rules ensure that the utility's portfolio development phase will include a sufficient quantity of bids across various generation resource types such that alternative resource plans can be created.

The utility develops multiple portfolios in the model analysis including the utility's preferred portfolio, a least-cost portfolio, and other portfolios that address varying strategies as identified in the Phase 1 decision, such as increasing amounts of renewables or differing plant retirement decisions. In 2016, Xcel Colorado included 11 portfolios in its Phase 2 Report.[xlviii] Then, using a production cost model, the selected portfolios are evaluated under varying assumptions.[27] These "sensitivity analyses" include variations in fuel cost, carbon cost, financial criteria, etc.

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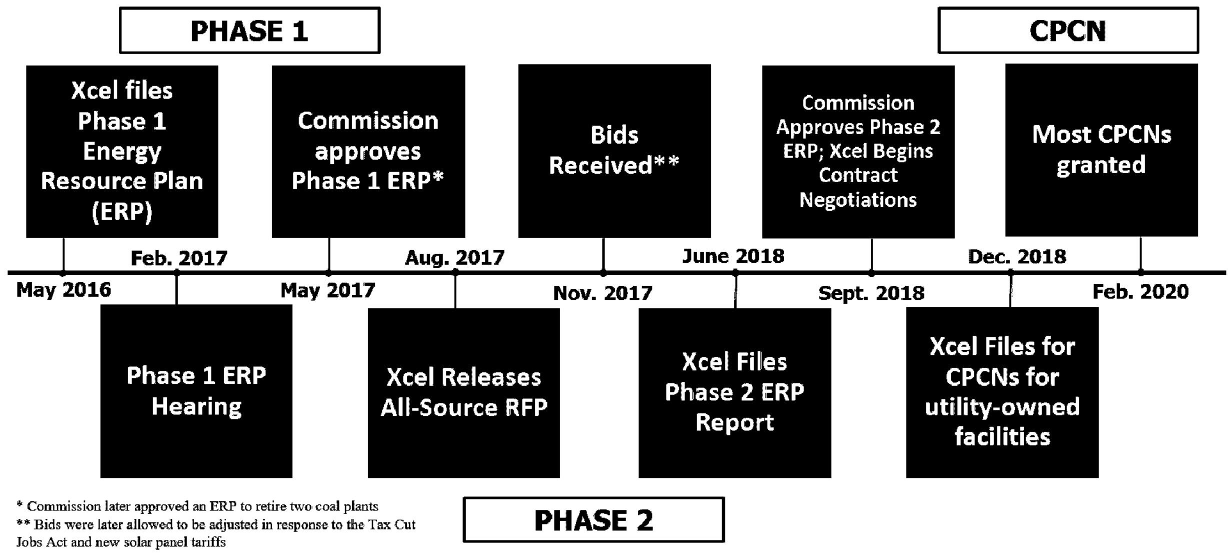
[26] Even though there are three bidding forms for intermittent, dispatchable and semi-dispatchable resources, all of these projects "compete" in the model by being modeled simultaneously.

[27] In addition to production cost models, Xcel Colorado also conducts power flow analyses to estimate transmission upgrade costs associated with each portfolio. Power flow analyses are done for portfolios, not for individual projects.

Figure 2: From IRP to Procurement: How long does it take to do all-source procurement the Colorado Way?



It is important to highlight that the outcome of the modeling of specific bids in Phase 2 can result in very different outcomes than for generic resources evaluated in Phase 1. In 2016, Xcel Colorado's recommended portfolio was substantially different than predicted by the system planning model in the Phase 1 planning study. For example, Xcel Colorado's base case had not predicted any storage resources would be selected. When real world competition was brought to bear, the resource mix was different than anyone had anticipated, both in terms of generation units selected and cost.[xlix]

The entire all-source RFP process is explained in the utility's bid report, which is filed 120 days after bids are submitted. The utility's report is submitted for review, along with model data, by PUC staff and parties. After receiving comments, the PUC issues its Phase 2 Decision, usually without a hearing. The Phase 2 Decision ratifies (or changes) the recommended resource portfolio, authorizing the utility to proceed to bid negotiations, contract awards, construction and operation.

Finally, it is worth noting that implementation of all-source procurement practices has enabled the Colorado PUC to establish that plan approval results in a rebuttable presumption that utility actions taken in concert with approved plans are prudent for purposes of inclusion in PUC-approved consumer rates. This provides value to power providers, utility customers, and the utility itself.

Key Advantages of Colorado's All-Source Procurement Practices

Colorado's all-source procurement practices demonstrate several important approaches to regulating a monopsony utility and achieving a more cost-effective generation solution than a single-source RFP.[l]

- The Colorado PUC reviewed and approved a range of need scenarios for acquiring new power, but did not specific a specific capacity quantity or technology.
- The Colorado PUC reviewed and approved the conditions for acquiring new power. Xcel Colorado was required to conduct an all-source solicitation open to projects regardless of technology, nameplate capacity, location, or transmission requirements to fill the identified capacity and energy need. The terms of the order establish substantial transparency, affording potential bidders clarity as to requirements their bids must meet.
- Xcel Colorado operates a process that allows for fair competition between IPPs and utility ownership proposals. It must consider all bids that meet specified minimum criteria based on cost, schedule, and other relevant performance factors. This addresses bidder concerns about arbitrary decision making and reduces risk premiums that bidders might otherwise feel compelled to include in their bids.
- Xcel Colorado allows for flexible technology outcomes by using its capacity expansion model to optimize resource portfolios based on the best bids in combination. It does not simply evaluate and rank bids individually. This approach benefits utility customers by attracting a maximum diversity of bids since there is potential for any project to fill a niche.
- The Colorado PUC reviews and discloses contract terms in advance, removing uncertainty for bidders.

As suggested above, the Colorado PUC's procurement practices demonstrate robust attention to potential abuses of the utility's market power without compromising the utility's obligation to meet system reliability needs.

ALL-SOURCE RFP CASE STUDY: PNM - EFFECTIVE ENGAGEMENT OF STAKEHOLDERS, BUT AFTER THE RFP

In its 2017 integrated resource plan, PNM recommended abandoning its interest in the San Juan coal plant and replacing it with projects procured in an all-source RFP process. In New Mexico, IRPs are not approved by the New Mexico PRC, and so PNM relied on its IRP to issue an RFP without a determination of need by the PRC.[li]

However, the PRC was not entirely disengaged from determining the need filled by the RFP and approved the process for considering abandonment of the San Juan coal plant in a 2015 stipulation related to environmental concerns. [lii] The stipulation also referenced stakeholder review of the IRP and inclusion of "renewable resource options beyond" those identified in the IRP. Based on those agreed conditions, the resulting abandonment proceeding included review of most of the modeling assumptions and bid evaluation practices used in PNM's procurement process.[liii]

After the PRC ordered the proceeding, New Mexico enacted the Energy Transition Act on March 22, 2019.[28] In addition to gas, solar, and battery storage resources intended to replace the San Juan coal plant, PNM's application also included the securitization component of the ETA, which helped PNM propose a revenue requirement that was lower than its 2017 IRP forecast.[liv]

The RFP resulted in 345 bids, plus 390 bids in the supplemental storage RFP.[lv] PNM contracted with an "owner's engineer," whose role included serving as an "independent resource to review, summarize, and evaluate bid information."[lvi] However, other aspects of the owner's engineer role may not have reflected the usual understanding of an "independent evaluator."[lvii]

Bid prices were very cost-effective, as shown in Table 5. In some cases, such as wind, the prices were similar to the Xcel Colorado prices (see Table 1). But for solar and battery hybrid projects, the prices were more than 40 percent lower, indicating rapid price changes in the market.

As of publication of this report, the PRC has not ruled on PNM's proposal. However, the proceeding is noteworthy because intervening parties were able to, and in fact did, propose alternative portfolios and challenge the utility's technical assumptions in evaluating those portfolios. The PNM portfolio is compared to the portfolio recommended by the Coalition for Clean Affordable Energy, an environmental and consumer advocacy organization, in Table 5 below.

[28] The Energy Transition Act sets aggressive clean energy goals for the state (50 percent carbon free by 2030, 100 percent by 2045) and provides for financial assistance to transition communities reliant on coal. This meant securitization for San Juan to reduce the rate impact to ratepayers and $40 million to assist plant employees and mine workers with retraining and severance pay.

Table 5: Comparison of Portfolios Recommended by PNM and Coalition for Clean Affordable Energy (CCAE) to replace San Juan Coal Plant [lviii]

	PNM Portfolio	CCAE Portfolio	Resource price
Wind (already under contract)	140 MW	140 MW	$17 / MWh
Solar / Battery Hybrid	350 / 60 MW	650 / 300 MW	$19-20 / MWh + $7-10 / kw-mo
Standalone Battery	70 MW	0	$1,211-1,287/kW + $9-10 / kw-year
Gas Turbine	280 MW	0	$680 / kW + $3 / kw-year + fuel costs
Energy Efficiency in 2023	53 MW	69 MW	$263 / first-year MWh
Demand Response in 2023	38 MW	69 MW	$95 / kw-year
2022-2038 System CO_2 emissions	21.9 million tons	20.3 million tons	
Forecast System Cost 2022-2038 (net present value)	$5.26 billion	$5.33 billion[lix]	

Key Issues in the Review of PNM's Replacement Portfolio

Timing of the Proceeding

The scheduling of the abandonment, financing, and resource replacement proceeding was the subject of significant litigation. PNM sought to delay the proceeding until June 2019, arguing that its decision to abandon the San Juan coal plant superseded the approved stipulation agreement. The PRC forcefully disagreed, stating that PNM had already delayed the proceeding, an action that "may have already negated a significant portion of the Commission's abandonment authority - the practical ability to deny PNM's abandonment ..."[lx] The PRC further noted that the delay, "potentially legitimizes the concerns ... that PNM may be seeking to gain an advantage and box in parties that oppose PNM's choices with a time limit."[lxi]

PNM challenged the order in the New Mexico Supreme Court, which stayed the deadline of March 1, 2019 for filing of the proceeding. The court rejected PNM's challenge, which resulted in PNM filing its application on July 1, 2019, nevertheless effectively achieving PNM's original schedule objective. PNM's filing of a consolidated abandonment, financing and resource replacement proceeding was not what had been originally contemplated by the PRC, but the PRC accepted the filing as "responsive" to its order and adjusted the schedule to allow for a 15-month review period.[lxii]

Consideration of Factors Included in Energy Transition Act

The Energy Transition Act provided that "cost, economic development and the ability to provide jobs with comparable pay and benefits to those lost due to the abandonment of the qualifying generation facility are to be considered in evaluating replacement resources." Among other factors and considerations, replacement resources were also to be those "with the least environmental impacts, and those higher ratios of capital costs to fuel costs."[lxiii]

PNM argued that its preferred portfolio, which was developed on the basis of reliability and cost, met the ETA policy factors.[lxiv] It argued that the ETA did not alter "PNM's general planning practices."[lxv] PNM also explored these factors by creating three additional portfolios that focused on replacement generation located in the school district, having high renewable energy content, and making progress towards zero-carbon goals. The additional portfolios that PNM evaluated for increased consideration of those factors did not result in any changes to its recommended portfolio.[lxvi]

The CCAE portfolio was one of the portfolios suggested by intervenors that sought to achieve these goals by placing solar and battery storage projects in the school district rather than the gas turbine projects favored by PNM. According to CCAE, this would increase investment in the school district from $210 million to $447 million, and construction jobs from 375 to at least 500 compared to PNM's proposal.[lxvii]

Technical Problems with RFP Evaluation Modeling

Intervenors raised several technical issues related to PNM's RFP modeling. Some of the issues with greater impact on the results included:

- Inaccurate or constrained energy efficiency and demand response programs and costs
- An inflated forced outage rate at a power plant
- Consideration of correlated outages of gas generators
- Excessive limits on power imports during peak periods
- Effective load carrying capabilities for wind and battery resources were too low
- Relationship between renewable generation output patterns and weather variations
- Use of an unsanctioned reliability metric for system flexibility
- Failure to use a social cost of carbon

Although PNM did accept one technical critique of its modeling, it generally disagreed with the intervenors.[lxviii] In addition to arguing that the higher cost of the intervenor portfolios was significant, PNM also argued that many of the technical adjustments made by intervenors would result in higher reliability risks. Thus, much of the argument about which portfolio was best justified by general planning practices and the ETA factors hinged on whether PNM or intervenor witnesses' testimony is deemed more reliable.

Post-RFP Constraints on Battery Storage

PNM issued its supplemental RFP for energy storage in April 2019, partially in response to the ETA enactment. After determining the optimal portfolio might include as much as 170 MW of battery storage, PNM raised several concerns about the 150 MW storage component of the winning solar-plus-storage bid.[lxix]

- Investment tax credit rules would prevent the storage facility from "recharging with cheap excess wind energy from the grid at night"
- New storage created technology risk and risk of non-performance due to this being larger than any previously built battery storage facility, and the bidder never having constructed a battery storage facility
- The location, far from the Albuquerque load center, is disadvantageous from a system balancing perspective. More optimal locations would allow deferral of T&D facilities and provision of ancillary services.
- Investing now would forgo future price decline and technology innovation opportunity
- By not owning the facility, PNM would not gain operational knowledge of a new technology[lxx]

Based on these concerns, in June 2019, PNM limited total battery storage to 130 MW and individual projects to 40 MW.[lxxi] This occurred about one month after PNM received bids in its supplemental storage RFP,[lxxii] and PNM's evaluation of those bids was only conducted under the limitations set in June 2019.[lxxiii]

Intervenors challenged the battery storage limitations, citing more extensive industry experience with the technology than given credit by PNM, PNM's study by the Brattle Group recommending roughly twice as much battery deployment, a failure to value the locational benefits of storage, and a misunderstanding of the economic value of immediate procurement.[lxxiv]

Access to PNM's Modeling Software

The PRC required PNM to make its models available to seven intervenors without charge.[lxxv, lxxvi] PNM used two primary models in its work, EnCompass for capacity expansion and SERVM for reliability (it also used PowerSimm). PNM made the modeling software available using either PNM running the models using resource portfolios selected by the parties, or by purchasing a license for parties to use the models on their own. Access to the models resulted in a relatively clear distinction being drawn between the parties' positions.

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: GEORGIA POWER PROCURES RESOURCES SEPARATELY

In its 2019 IRP proceeding, the Georgia PSC authorized six single-source RFP processes.[lxxvii] This case study will focus on two near-term utility scale procurement processes, a capacity-based RFP primarily targeted at gas-fueled plants and a renewable energy RFP.[lxxviii] The Commission also authorized smaller-scale procurements, including distributed generation solar resources,[lxxix] biomass,[lxxx] and battery storage.[lxxxi] Georgia's procurement processes rely on RFPs with a number of relatively robust requirements, including an independent evaluator, disclosure of contract terms in advance, and close scrutiny by PSC staff.[lxxxii] Intervening parties recommended the use of all-source procurement; however, this recommendation was not implemented. While not specified in the order, affiliate, self-build and turnkey projects are generally allowed by the PSC.[lxxxiii]

The capacity procurement, primarily targeted at gas-fueled plants, was proposed to address two needs. First Georgia Power proposed to retire Plant Bowen Units 1-2, with a capacity of 1,450 MW of coal-fired generation for economic reasons. Georgia Power anticipated that the retirement would trigger a need for 1,000 MW of replacement capacity in 2022. Second, Georgia Power identified an unspecified capacity need in 2026-28.[lxxxiv]

The renewable energy procurement, primarily targeted at solar plants, was proposed by Georgia Power in response to analysis that showed it would reduce system costs to add additional solar power. Georgia Power initially proposed a total of 1,000 MW and agreed to a larger amount in negotiations with PSC staff. The PSC raised the total amount of renewable energy procurements to 2,260 MW, including smaller-scale procurements mentioned above.

Georgia Power's use of concurrent, single-source procurements emerged over the past decade as solar procurements emerged as a significant component of the utility's resource strategy. Georgia Power's most recent capacity RFP was initiated in 2010 (known as the "2015 RFP"), and it resulted in 47 proposals.[lxxxv] In 2017, a solar procurement resulted in 174 proposals.[lxxxvi]

Capacity Procurement Issues in the Georgia IRP Proceeding

The Georgia PSC largely ratified Georgia Power's proposal for "firm" capacity to replace coal plants and meet a 2028 capacity need in its 2019 IRP decision.[29] According to utility witnesses, the procurements will limit participation to "combined cycle units, combustion turbines, and renewable resources combined with storage."[lxxxvii]

Intervenors challenged this narrow eligibility standard on two grounds. First, several intervenors provided evidence that renewable energy and storage could contribute to meeting the capacity need. Second, the intervenors pointed out that the retirement would lead to a need for both

[29] "Firmness" is defined by Georgia Power to mean providing "capacity and energy ... from specific, dedicated generating unit(s) on an unencumbered first-call basis and priority." Georgia Power, *2015 Request for Proposals*, Georgia PSC Docket 27488 (April 20, 2010), p. 7.

energy and capacity, and that the energy need not be fully supplied by a "firm" capacity resource. Their recommended remedy of an all-source procurement was not adopted in the final order.

Capacity Value of Renewable Energy and Storage

In the Georgia Power IRP proceeding, several intervenors advanced three arguments that renewable energy and storage could contribute to meeting the capacity need.

First, intervenors argued that renewable energy does provide capacity value. For example, the PSC's advocacy staff had recommended that "all types of generation resources that can provide capacity be permitted to bid."[30] Utility witnesses agreed that the "capacity equivalents" for solar power considers "the reliability improvement of that resource compared to the reliability improvement [of a] dispatchable resource."[lxxxviii] Georgia Power uses an approved method to determine the capacity value of renewable energy projects in its procurements.

Second, intervenors submitted evidence that proven technology could enhance renewable energy's capacity value.[lxxxix] Large-scale solar and wind power plants can be built with the capability to receive a dispatch signal from the control center or to respond directly to grid conditions.[xc] For example, in partnership with the National Renewable Energy Laboratory and the California Independent System Operator, First Solar demonstrated that its 300 MW solar PV plant could follow dispatch signals from the grid operator with greater accuracy than a gas-fired power plant, providing important reliability services in the process.[xci] Counter-intuitively, application of intentional pre-curtailment of solar results in *less* overall curtailment.[xcii] In addition to reducing curtailment, the intentional curtailment practices used in the "full flexibility" mode of solar dispatch provide operating reserve services including downward and upward regulation.[xciii] This evidence pointed towards an opportunity for additional value, beyond that accepted by Georgia Power.

Third, intervenors argued that storage projects need not be dependent on co-located renewable energy plants, and that their operation could achieve greater benefits than the utility was acknowledging. In the past, Georgia Power has required that energy storage bids must be co-located at a renewable energy plant site, charged solely from the renewable energy plant, and must operate to provide only one storage use.[31] Georgia Power witnesses did agree that multiple

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[30] This recommendation was linked to a provision stating, "... language should be included in the RFP that would permit the Company to reject all bids at its discretion. This language would give the Company and the Commission more options to address future capacity needs." While the stipulation appears to have used a narrower eligibility standard, the broad discretionary language is included in the stipulation. *See* Tom Newsome et. al., *Direct Testimony on Behalf of the Georgia Public Service Commission Public Interest Advocacy Staff*, GPSC Docket No. 42310 (April 25, 2019), p. 114; *and* Georgia Public Service Commission, *Order Adopting Stipulation as Amended,* Docket No. 42310 (July 29, 2019), Stipulation p. 4.

[31] The storage use options allowed by Georgia Power are smoothing (minimize moment-to-moment variations in energy output), firming (guaranteeing the daily energy output profile), and shifting (delivering energy in more valuable hours, with delivery decisions made by either the seller or Georgia Power). Georgia Power, *2020/2021*

storage uses could be provided by the same facility, but expressed concern over accounting impacts that might occur if Georgia Power assumed operational control over a stand-alone storage project.[xciv]

At the end of the IRP proceeding, it appeared that Georgia Power did not accept the intervenors' evidence in favor of updating its concept of "firm" capacity value. The utility maintained its position that stand-alone renewable energy projects cannot bid into its capacity RFP, even if updated to provide "full flexibility" capability, and also its position that storage projects would need to be co-located at a renewable energy site with operational control by the project owner.

Procurement of Capacity and Energy

Some of the intervenors also advanced the argument that even in a capacity RFP, the utility was also procuring energy, and that it should consider resources that only offered energy in the interest of procuring an optimal mix of capacity and energy resources. Even though a large part of Georgia Power's requests is based on the need to replace energy from Plant Bowen Units 1-2,[32] Georgia Power's RFP considers only capacity for firm, or "guaranteed," generation.[xcv]

Georgia Power's witnesses speculated on what the capacity RFP would likely procure, pointing out that gas plants were coming off contract capable of delivering low cost bids to meet the assumed capacity need,[xcvi] which appeared to refer to over 1,000 MW of gas turbine PPAs.[33] Gas turbine energy generation is among the most expensive energy resources, usually dispatched for reliability and ancillary services at very limited utilization rates. The three plants whose contracts are expiring have been used less than 7 percent of the time.[xcvii] In effect, these gas turbine units would meet the firm capacity needs defined by Georgia Power, but could not supply cost-effective energy to substitute for the energy need.

The actual amount of energy needed from the procurement is not public. Georgia Power redacted all meaningful planning data in its IRP related to what services, such as energy, they might need beyond 1,000 MW of capacity. For example, it is unclear whether Georgia Power's bid evaluation will favor units that mimic the 2017 dispatch of Plant Bowen Units 1-2 or will have some other preferred dispatch. This means that it remains unclear to bidders what types of energy resources might perform cost-effectively in the bid evaluation process.

Renewable Energy Development Initiative, Request for Proposals for Utility Scale Renewable Generation, GPSC Docket No. 40706 (December 10, 2018), p. 15-16.

[32] In 2017, Plant Bowen Units 1-2 generated 5.3 million MWh, representing an annual combined capacity factor of 42 percent (51 percent for Unit 1 and 33 percent for Unit 2), which is typical of these units since 2012. Direct Testimony of Mark Detsky, on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association, Georgia PSC Docket No. 42310 (April 25, 2019), p. 26.

[33] The expiring peaking combustion turbine PPAs: MPC Generating - 301 MW GT; Walton County Power - 436 MW GT; Washington County Power - 302 MW GT. See, Stipulation in Docket No. 22528-U, dated Nov. 2, 2006.

Renewable Energy Valuation Issues in the Georgia IRP Proceeding

The PSC expanded three renewable energy procurements proposed by Georgia Power (utility-scale solar, distributed generation solar, and battery storage), and added a fourth for biomass. The stipulation approved by the PSC also deferred several issues related to the valuation of renewable energy to consultation between the utility and Commission staff, primarily adjustments to the capacity equivalency of solar power that affect capacity value.

The issues related to valuation are critical because prior RFPs have specified price plus any costs for renewable energy must not exceed the projected avoided cost on a levelized basis.[xcviii] These values are calculated on a project-specific basis, using a process known as the Renewable Cost Benefit (RCB) Framework,[xcix] and are not disclosed to bidders. Not only are bidders competing against each other, but they must also keep costs below an unknown ceiling.

The RCB Framework is essentially an enhanced version of conventional avoided cost methods. Georgia Power's RCB Framework is relatively comprehensive in that it supports calculation by resource (e.g., wind, utility-scale, and distributed solar) at the project level. The calculations consider several measurable system costs or benefits, generally relies upon utility-specific hourly data, and is updated based on new and improved data.[c]

However, Georgia Power's methods for evaluating renewable energy resources in its resource planning and procurement processes were heavily critiqued by other parties. The issues included the date of the next generation capacity need, the methods for assessing the system benefits of renewable energy, and several modeling issues including claims that basic statistical concepts were misapplied.[ci]

The critiques raised by experts for parties other than the PSC staff were generally not addressed in the PSC order approving the stipulation. Few of these concerns can be raised during the process for approving the renewable or capacity RFPs, or approving any resulting procurement plans.

There is a direct connection between the decision to evaluate renewable resource bids outside the baseline resource plan and the use of separate procurements for capacity, renewable and storage resources. This is because it is impossible to construct an ideal portfolio mix when evaluating bids one-by-one. A bid ranking process could end up with all solar projects, which would not be an effective portfolio. Furthermore, because the operation of energy storage projects depends on the resources with which they are paired, the RCB Framework is "not well-suited to evaluating energy storage resources … and may also require portfolio-level modeling."[cii] Georgia Power's planning practices appear to be diverging into three separate processes,[34] with inefficient overall optimization.

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[34] This commentary does not address the energy efficiency planning process, which is a fourth separate process.

Bid Evaluation - Primarily Based on Economic Analysis

After receiving Commission approval in an IRP proceeding, Georgia Power conducts its RFPs with a focus on an economic comparison between bids. There are some differences in the methods for evaluating capacity and renewable energy bids.

- Capacity bids - ranked on net cost ($/MW) considering:[ciii]
  - Fixed costs - such as purchase price, capacity cost payment, fixed O&M, fuel pipeline costs
  - Equity costs - for a capital lease, cost impact to the utility balance sheet
  - Production costs - a production cost model simulation is conducted for each proposal, based on cost and operating characteristics of the unit compared to a reference simulation without the bid
  - Transmission costs - model simulated impacts on the transmission system, including system upgrades and impact on energy losses
- Renewable energy bids - ranked on net benefit ($/MWh) considering:[civ]
  - Bid costs
  - Projected avoided costs, according to the RCB Framework
  - Transmission and distribution costs

With the exception of the capital lease issue in the capacity RFP, the two evaluation methods appear very similar in their general approach to bid ranking, other than the evident difference in ranking based on cost per capacity (MW) and per energy (MWh). Both evaluations consider more than just the simple price of the bid, reaching a net cost (or benefit) result after considering impacts on the overall system dispatch costs.

The overall system dispatch costs are therefore very important factors for bidders to consider in developing competitive bids. However, bidders are provided very little specific information about the production, transmission, and other cost model simulations.

- In a capacity RFP, bidders were informed that, "proposals located in areas of major load (net of generation) would tend to receive a more favorable transmission facilities cost evaluation (since power export capability from the area will not be required) than proposals located in areas that have generation significantly in excess of area load where power export capability from the area may be required."[cv] However, no information about where these locations might be was offered, nor were specific cost multipliers made available.
- In a renewable energy RFP, bidders were provided with relative avoided energy costs for typical days by month. For example, the peak hour was 2:00 p.m. on an August day, while avoided energy costs were represented as 60 percent of that value for 2:00 p.m. on a November day.[cvi] These values are, of course, averages over sunny and cloudy days within the same month.

In these RFPs, although several non-price evaluation factors are noted, such as bidder development experience and specific facility location issues, these appear to be relatively straightforward and not likely to exhibit bias. If the bidder is proposing to sell the unit to Georgia Power, then there would be due diligence on the operating costs. Contracts of varying lengths are accepted.

After evaluating individual bids, Georgia Power assembles several portfolios from the best performing individual bids. Production and transmission costs are re-evaluated for each portfolio in order to identify the best combination of bids.[cvii] The Georgia PSC has a longstanding RFP rule that requires an independent evaluator, extensive staff involvement throughout the process, and PSC approval of the final RFP.

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: MINNESOTA POWER CONSTRAINS ITS RFPS

In 2018, the Minnesota PUC approved Minnesota Power's portion of the Nemadji Trail Energy Center (NTEC), a 525 MW natural gas combined cycle plant in Wisconsin. Minnesota Power would operate and own its share of the plant through agreements with an affiliate and a cooperative utility partner. The NTEC plant was selected in a single resource (gas) RFP, even though the RFP proceeded from an IRP in which the MPUC clearly contemplated an all-source procurement.

Consideration of the NTEC plant came out of Minnesota Power's 2015 IRP. In that IRP, the PUC approved up to 100 MW of solar power, 300 MW of wind power, and a demand response competitive bidding process, exceeding the utility's requests in each instance.[cviii] Minnesota Power was also authorized to idle two coal units, make certain transmission investments, and enter into short term contracts. Minnesota Power was denied approval of certain pollution control equipment at a coal plant. However, Minnesota Power was also authorized to "pursue an RFP to investigate the possible procurement of combined-cycle natural gas generation, with no presumption that any or all of the generation identified in that bidding process will be approved . . . ."

While the RFP was specifically authorized for gas generation, the PUC's order also emphasized that "Minnesota Power's evaluation of replacement generation should not be limited to one resource." Accordingly, the PUC required that the next resource plan include a "full analysis of all alternatives." This requirement was in response to parties who had argued that the solicitation should be fuel-neutral, considering renewables, demand-response measures, or customer-owned generation. As discussed below, this did not happen. A lack of clarity in the order ultimately disappointed parties who believed that the PUC intended for the results of the RFP to be submitted with an updated IRP.

Minnesota Power 2015-16 RFPs

Minnesota Power conducted five RFPs in 2015 and 2016 to develop its 2017 EnergyForward Resource Package. Two of the RFPs, for solar and wind, were relatively uncontroversial, and led to procurements as described above. The customer co-generation RFP did not receive any responses.[cix] The demand response RFP only received one response and did not result in procurement,[cx] and intervenors challenged its effectiveness due to its short response time (less than two months, with the first information session occurring only six weeks before the deadline), the requirement to participate at up to 800 hours per year (creating a large risk), and uncertainties about participation requirements.[cxi]

The gas resource RFP sought "up to 400 MW of dispatchable natural-gas-fired capacity and associated unit-contingent energy."[cxii] The RFP required PPA pricing for a minimum term of 20 years with a purchase option and requested additional buy-out options. Bidders were required to provide pricing, cost and performance details in their bid. In some cases, the independent evaluator used an outside expert to estimate certain costs.

Fifteen gas resource proposals were deemed qualified.[cxiii] However, two bids were later eliminated based on a FERC ruling on transmission that made resources outside of the local resource zone more "problematic."[cxiv] The two "problematic" bids were apparently not provided an opportunity to address the issue.

The independent evaluator used results from Minnesota Power's dispatch model to calibrate its own bid evaluation models used in its assessment. Each bid was individually evaluated to estimate the net impact on Minnesota Power's system production costs. Minnesota Power shortlisted two projects, including the NTEC bid from Minnesota Power's affiliate and an unspecified independent PPA. The independent evaluator agreed with Minnesota Power's selection of a 250 MW proposal for the NTEC plant from the utility's affiliate.

Minnesota Power's modeling of NTEC occurred in its capacity-expansion model. In the first step, the utility compared the NTEC plant to a number of generic resource alternatives covering a wide range of technologies.[cxv] Notably, neither bid alternatives to the NTEC plant from the gas resource RFP nor any of the selected or bid alternatives for the solar or wind RFPs were included in this step. In the second step, the NTEC plant was combined with the results of the solar and wind RFPs and compared to two renewable capacity portfolios and one gas peaker portfolio.

Minnesota Power was criticized for delays in its negotiations, which resulted in the estimated need being revised twice. Only the NTEC bidder was allowed to revise the proposal, "in essence MP/ALLETE pursued a single source rather than issuing a new RFP consistent with the revised needs or allowing all bidders the opportunity to address the new need."[cxvi] The public advocate identified a need to create a "formal, Commission-approved resource acquisition process."[cxvii]

The gas resource RFP received the most extensive challenges from intervenors, and the administrative law judge agreed that "Minnesota Power used unreasonable assumptions in its modeling, failed to analyze a reasonable range of resources, and placed constraints on the model that resulted in [a bias] in favor of NTEC."[cxviii] For example, intervenor witnesses challenged the use of winter peaking constraints (MISO is a summer peaking system), the use of capacity values for renewable energy that are lower than standard in MISO, and the use of unnecessarily large sizes for generic resources.[cxix] Nonetheless, the MPUC overruled the administrative law judge and approved the NTEC plant agreements.

The wind RFP received a total of 94 bids, and the solar RFP received 83 bids plus two self-build projects.[cxx] After evaluating the initial solar RFP bids, Minnesota Power decided to pursue a 10 MW project and invited bidders to resubmit at that size. The Commission reviewed the results of those RFPs in separate proceedings. Issues were raised in those proceedings that related to the quality of the renewables RFPs and the fulfillment of the IRP goals. After the winning bid from the wind RFP was selected, the utility and the developer agreed to a "repricing mechanism" was added to address some uncertainties that had developed, and Minnesota Power also agreed to consider taking an equity interest in the project. In the solar RFP, some of the terms and conditions were questioned by the public advocate. Because the utility had reduced solar procurement from the RFP goal of 100 MW to 10 MW, the Commission ordered Minnesota Power to further discuss its modeling of solar resources with the public advocate.

Minnesota Commission Discussion of All-Source Procurement

In contrast to the Georgia decision, the Minnesota commissioners engaged in substantial discussion of issues related to the suitability of Minnesota Power's procurement practices. Despite a lack of evidence from Minnesota Power demonstrating their consideration of clean alternatives to the gas-fired power plant, ultimately the PUC authorized NTEC's procurement.

Key at issue was the burden of proof Minnesota Power faced to justify NTEC as the optimal resource to meet future system needs. The PUC's procedural order established that, "Minnesota Power bears the burden of proving that the proposed gas plant … is needed and reasonable based on all relevant factors …" Among the relevant factors was consideration of alternatives such as wind and solar, storage, demand response, and energy efficiency. Yet when presented to the PUC, the case focused on the gas plant's approval, as there were no alternatives that could be selected if determined more reasonable.[cxxi]

In its final decision on the NTEC plant, the PUC voted 3-2 to reverse the administrative law judge who found that Minnesota Power had not met its burden of proof to justify the procurement of NTEC. The dissenting commissioners felt that the NTEC plant was not needed for capacity, and was not cost-effective as an energy resource.[cxxii] There was significant disagreement among the parties regarding what the prior order required -- one commissioner explained that he believed the order had called for the RFP to seek "intermediate capacity needs" rather than being limited to a gas resource.[cxxiii]

Approval of the RFP thus appeared to depart significantly from the order authorizing the RFP. In reversing, the PUC did not explicitly find that Minnesota Power had met its burden of proof. Instead, it evaluated evidence "based on the totality of the record"[cxxiv] by the Department of Commerce which supported a finding NTEC was "needed and reasonable based on all relevant factors."[cxxv] By applying a lower burden of proof than the IRP standard, it appears concerns expressed by intervenors regarding the burden of proof had been realized.

In considering the NTEC plant decision, there are several relevant lessons that may be considered when developing practices for all-source procurement.

- Utility proposals to transact with affiliates and own specific resources may justify higher burdens of proof such as requiring monopsony utilities to test the market for clean energy portfolios that provide the same service.
- Competent and transparent analysis can provide regulators with strong evidence for a decision. Regardless of one's perspective on the correct decisions in this matter, the record is clear that the administrative law judge and all five commissioners were well-informed by all the experts who testified in the proceeding.
- Commission decisions are more constrained when considering the results of a single-source RFP. The thumbs up/down nature of the decision raises the stakes of rejecting the utility's recommendation, requiring the utility to start from scratch on a potentially accelerated timeline if procurement is denied.
- Commission orders directing all-source procurements need to be clearly worded and establish the statutory standard of review up front. Once the utility has proceeded to conduct an RFP, a regulator will find it difficult to remedy any discrepancies with its initial order.

The only matter which the record of this case leaves uncertain is whether the gas resource RFP was truly competitive. Neither the utility nor the independent evaluator provided much evidence regarding how robust the responses were, as no details regarding alternative gas resources were provided outside of trade secret seals.

ALL-SOURCE RFP CASE STUDY: NIPSCO "SURPRISED" BY LESS EXPENSIVE RENEWABLES

NIPSCO used an all-source RFP for its 2018 IRP, and it began implementation in 2019. The all-source RFP was one of several process improvements that NIPSCO implemented based on feedback from its 2016 IRP.[cxxvi] While the 2016 IRP had called for only two unit retirements in 2023, in the 2018 IRP NIPSCO determined that it could move forward with retiring all its coal plants. The key development was evaluation of "the all source Request for Proposal (RFP) solicitation that NIPSCO ran as part of its 2018 Integrated Resource Plan process – which concluded that wind and solar resources were shown to be lower cost options for customers compared to other energy resource options."[cxxvii]

NIPSCO received 90 total proposals in response to its RFP.[cxxviii] Those proposals were evaluated in its system planning models in two steps. First, NIPSCO evaluated eight different coal retirement portfolios, with varying retirement timings up to and including full retirement in 2023.[cxxix] Second, after selecting the preferred retirement path, NIPSCO evaluated six different replacement generation scenarios.[cxxx] The evaluation considered several metrics, and included stochastic evaluation of various cost driver uncertainties (e.g., fuel cost).

NIPSCO concluded that it should proceed to acquire 1,053 MW of solar, 92 MW of solar plus storage, 157 MW of wind, 50 MW of capacity market purchase, and 125 MW of demand side management resources, along with the retirement of all coal plants by 2028.[cxxxi] The selected portfolio maximized renewables and utilized longer duration contracts relative to the other portfolios. The selected portfolio is projected to have roughly 1 million tons of carbon emissions in 2030, compared to 18.2 million tons in 2005.[cxxxii] (The retirement portfolio analysis did not include carbon emissions.) Other replacement generation portfolios studied had up to 3.1 million tons of emissions. As shown in Table 6, relative to the 2016 IRP Scenario, NIPSCO was able to reduce forecast costs by $1.1 billion, or nearly 10 percent.

Table 6: NIPSCO 2018 IRP / RFP Evaluation of Alternate Portfolios (30-year net present value)[cxxxiii]

Portfolio	**Description**	**System Revenue Requirement**
Base	Coal in service through end-of-life	$ 15.4 billion
2016 IRP Scenario	40% coal in 2023	$ 12.9 billion
Preferred Retirement Path	15% coal in 2023	$ 11.3 billion
Average-Low Carbon	More renewables, longer contracts	$ 11.8 billion
Savings vs 2016 IRP Scenario		**$ 1.1 billion**

In a recent webinar, Mike Hooper, NIPSCO senior vice president explained that NIPSCO "ran an RFP process inside of the integrated resource plan to get a better indication of what the real market data looked like." He further explained that, "We kind of made an assumption that as the results came back it would be very much similar to 2016, particularly where we sit in the world, that natural-gas generation would be the most cost-effective option. ... And as we ran this RFP and got our results back, we were surprised to see that wind ...and then solar ... were significantly less expensive than new gas-fired generation."[cxxxiv]

ALL-SOURCE RFP CASE STUDY: EL PASO ELECTRIC FINDS VALUE

Although the public record is sparse, the 2017 El Paso Electric RFP is a good example of a utility finding unexpected value through an all-source procurement process. In 2017, El Paso Electric issued an all-source RFP for 370 MW of generating capacity. Utilizing an independent evaluator, the utility received and evaluated 81 bids from a variety of resources.[cxxxv]

El Paso Electric evaluated the proposals using a two-stage process. First, viable proposals were evaluated based on levelized cost, grouped by resource type (conventional/dispatchable, renewable, load management, or energy storage) and type of proposal being offered (PPA, purchase, or equity participation). The utility then selected the top-ranking proposals from each group to shortlist.[cxxxvi] Of those, only the top ranked solar and storage bids were modeled in a staged portfolio process to determine the winning bids.[cxxxvii]

In 2018, the utility announced that it would meet the capacity needs with 200 MW of solar, 100 MW of battery storage, and a new 228 MW gas peaker plant. While El Paso Electric appears to have expected to obtain mainly peaking units to meet the 370 MW summer peak need, the utility ended up procuring 528 MW (nameplate) of generating resources.[cxxxviii]

SINGLE SOURCE RFP CASE STUDY: FLORIDA BIAS TOWARDS SELF-BUILD GENERATION

A general review of Florida's history with utility RFPs raises the issue of bias towards self-build options. The authors are unaware of any Florida utility RFP process that resulted in selection of a competitive bid: RFP "winners" have always been the utility's own self-build option. Private communications by one of the authors with attorneys who represent independent power producers suggest that there is a widespread perception that the Florida RFP evaluation process does not generally offer an opportunity for meaningful competition.

In one instance, Duke Energy Florida did reverse course with a "last minute acquisition" of Calpine's Osprey plant.[cxxxix] In that proceeding, two independent power producers submitted testimony stating that Duke Energy Florida's bid evaluation process was "oversimplified and structurally biased"[cxl] and "[biased] in favor of DEF's self-build projects."[cxli]

The Duke Energy Florida reversal does not prove that the Florida PSC ensures meaningful competition. In that reversal, the independent power producer had to invest relatively few resources to challenge the utility because the plant was already in operation. Although cost information is redacted from the docket, it appears that the cost advantage offered by Calpine over the self-build option was substantial.

Even after that reversal, developers appear uninterested in developing new project proposals in Florida, perhaps because new project bids require greater investment than bidding an existing facility. Just one year after Calpine obtained a reversal of Duke Energy Florida's self-build option, Florida Power & Light conducted an RFP. FPL reported, "No RFP submission received satisfied the minimum requirements of the RFP."[cxlii]

ALL-SOURCE RFP CASE STUDY: CALIFORNIA'S LOADING ORDER IS A SLOW PATH TO ALL-SOURCE PROCUREMENT

In 2003, California's energy agencies ruled that utilities must procure resources using the "Loading Order," which mandates that energy efficiency and demand response be pursued first, followed by renewables, and lastly clean-fossil generation.[cxliii] Though it took years to get up and running, a marquee case to apply the loading order occurred in 2013 and 2014, when Southern California Edison (SCE) announced it would pursue an all-source procurement including preferred resources to replace the local resources once provided by the San Onofre Nuclear Generating Station.

However, SCE's procurement was not truly "all-source." SCE established a minimum set-aside for preferred resources, implying that gas was going to be a major part of any selected portfolio. This procurement was also limited to local resources, in order to supply generation to a capacity-constrained area.[cxliv]

After a highly anticipated reverse auction, SCE procured 1,382 MW of gas-fired generation, with a smaller yet significant portion of utility-scale batteries (263 MW), efficiency (136 MW), renewables (50 MW), and demand response (70 MW).[cxlv] Reactions to the procurement were mixed - the storage procurement was unprecedented in size, attracting national attention and praise for innovative approach.[cxlvi] Allowing demand-side management to meet some of the need also represented a new application of the loading order. On the other hand, advocates were dismayed at the selection of local natural gas generation, critiquing both SCE's evaluation and the PUC's approval for failing to observe the loading order.[cxlvii]

The next opportunity for an all-source procurement in California is an ongoing proceeding at the CPUC. In November 2019, the CPUC directed SCE and several other related entities to undertake a 3.3 GW all-source procurement.[cxlviii] The procurement is for both "system resource adequacy and renewable integration capacity," and permits both existing and new resources to participate. The utility is required to conduct the "all-source solicitation in a non-discriminatory manner, with resources delivering the same attributes being valued in the same manner. SCE will be required to show its bid comparison metrics to the CPUC to justify its requested procurement."[cxlix]

Even as a leader in renewable integration with a 100 percent clean energy standard on the books, the CPUC is struggling to create rules and standards allowing the replacement of existing gas with new clean energy alternatives. For example, the CPUC is conducting a full examination of capacity credit of hybrid resources - combinations of renewables, storage, and other generation. But until that examination is complete, the CPUC is using an interim method for capacity credit of hybrid resources, which may constrain the availability of clean energy alternatives that can compete with existing gas-fueled resources.

The interim capacity credit method proposed by the CPUC assigns a hybrid resource the greater of the capacity credit values assigned to individual component resources.[cl] Under this framework, solar will most likely receive nearly no capacity credit (due to the excess of solar already on the grid) and four-hour storage barely qualifies for capacity credit. Behind-the-meter resources also receive no credit. Advocates hold that this will likely result in 50-60 year-old gas-fired power plants continuing to operate and receive capacity revenue after the procurement.[cli]

SINGLE-SOURCE RFP CASE STUDY: DOMINION ENERGY VIRGINIA CONSTRAINS THE MARKET

A recent Dominion Energy Virginia RFP demonstrates several issues related to over-procurement, self-build, transparency, and fairness. In November 2019, Dominion Energy Virginia initiated an RFP for up to 1,500 MW of new peaking resources.[clii] Resources must be "new and fully dispatchable." The resource need was identified by Dominion in its 2019 integrated resource plan, which selected a gas peaker plant.[cliii] Notably, the 2019 IRP was an update to a 2018 IRP that had been first rejected, then a refiled version approved with a strong caveat that the Commission did not "express approval . . . of the magnitude or specifics of Dominion's future spending plans."[cliv]

In response, LS Power asked the Virginia State Corporation Commission and Attorney General to suspend the RFP process.[clv] Among the complaints cited by LS Power are the requirement for resources to be "new," a lack of transparency regarding how Dominion's self-build alternatives will be evaluated (including potential disparity in risk of changes to environmental laws), and the lack of an independent evaluator. LS Power did not specifically complain about the exclusion of resource alternatives to gas peaker plants.

In December, Dominion Energy Virginia suspended the RFP without giving an explanation. A news article speculated that the suspension was in response to reports that the utility had over-forecasted demand for years.[clvi]

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: RESOURCE EVALUATION STIRRINGS IN NORTH CAROLINA

Commission interest in allowing competition between a wide array of resources to replace existing coal is emerging in North Carolina. A recent order by the North Carolina Utilities Commission (NCUC) identified similar concerns in a ruling on 2018 IRPs.[clvii]

- With respect to storage resources, the NCUC re-asserted its direction from a prior order in which it indicated that Duke Energy's "evaluations of [battery storage] technology … have not been fully developed to a level to provide guidance as to the role this technology should play going forward."
- With respect to energy efficiency resources, the NCUC noted that "Duke simply accepts its presently established levels of [energy efficiency and demand-side management] for planning purposes, and plugs those amounts into its IRP," and directed improved modeling of those resources.
- The NCUC further ordered that future IRPs "explicitly include and demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential [energy efficiency and demand-side management] programs, and a comprehensive set of potential resource options and combinations of resource options."
- The NCUC ordered Duke Energy to "remove any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles …"

The NCUC decision on Duke Energy's IRPs illustrates concerns about issues that also appear in other utility all-source procurement practices.

[i] Susan Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, Analysis Group (July 2008).

[ii] Dyson, Mark, Jamil Farbes, and Alexander Engel, *The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and can Strand Investment in Natural Gas-Fired Generation*, Rocky Mountain Institute (2018).

[iii] Ronald L. Lehr and Mike O'Boyle, *Steel for Fuel: Opportunities for Investors and Customers*, Energy Innovation Policy and Technology LLC (December 2018).

[iv] Colorado General Assembly, Colorado Senate Bill 19-236, *Sunset Public Utilities Commission,* Section 5 (May 2019).

[v] As of 2014. US Environmental Protection Agency, State Climate and Energy Program, *Energy and Environment Guide to Action* (2015), p. 7-10. See also Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013), p.5.

[vi] US Environmental Protection Agency, State Climate and Energy Program, *Energy and Environment Guide to Action* (2015), p. 7-24.

[vii] John Shenot et. al., *Capturing More Value from Combinations of PV and Other Distributed Energy Resources*, Regulatory Assistance Project (August 2019).

[viii] Washington State Utilities and Transportation Commission, *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*, Docket No. UE-151069 (October 11, 2017), p. 12.

[ix] Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities,* Lawrence Berkeley National Laboratory (October 2019).

[x] Regional power markets have developed mechanisms for capturing the value from solar, wind and other distributed energy resources. *See* John Shenot et. al., *Capturing More Value from Combinations of PV and Other Distributed Energy Resources,* Regulatory Assistance Project (August 2019).

[xi] Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities,* Lawrence Berkeley National Laboratory (October 2019).

[xii] Energy and Environmental Economics, Inc., *Planning Reserve Margin and Capacity Value Study*, Nova Scotia Power (July 2019), p. 64.

[xiii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), p. 92.

[xiv] Ryan Wiser and Mark Bolinger, *2018 Wind Technologies Market Report*, US Department of Energy (August 2019).

[xv] Mark Bolinger, Joachim Seel and Dana Robson, *Utility-Scale Solar*, Lawrence Berkeley National Laboratory (December 2019).

[xvi] Lazard, *Lazard's Levelized Cost of Energy Analysis - Version 13.0* (November 2019).

[xvii] Dyson, Mark, Jamil Farbes, and Alexander Engel, *The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and can Strand Investment in Natural Gas-Fired Generation*, Rocky Mountain Institute (2018).

[xviii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), Table 4.1.

[xix] Harvey Averch and Leland Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* (December 1962).

[xx] Steven Kihm, "When Revenue Decoupling Will Work ... And When It Won't," *The Electricity Journal* (October 2009).

[xxi] Rob Granlich and Michael Goggin, *Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform*, Grid Strategies LLC (November 2019), p. 11.

[xxii] Steven Kihm, Peter Cappers and Andrew Satchwell, *Considering Risk and Investor Value in Energy Efficiency Business Models*, ACEEE Summer Study on Energy Efficiency in Buildings (2016).

[xxiii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), p. 89.

[xxiv] Ron Binz et. al., *Practicing Risk-Aware Electricity Regulation*, Ceres (November 2014).

[xxv] Tyler Comings et. al., *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans* (March 7, 2019).

[xxvi] Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013).

[xxvii] Brendan Kirby, *Direct Testimony on Behalf of Southern Alliance for Clean Energy*, NCUC Docket No. E-100, Sub 158 (June 21, 2019).

[xxviii] Twenty states' IRP rules are "silent with respect to unit retirements." Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013).

[xxix] California Assembly Bill No. 32 (September 2006).

[xxx] California Senate Bill No. 1368 (September 2006)

[xxxi] California's loading order expresses a preference for energy efficiency, demand response, and renewable energy before considering fossil generation as a last resort. Sylvia Bender et al., *Implementing California's Loading Order for Electricity Orders*, California Energy Commission (July 2005).

[xxxii] Colorado General Assembly, Colorado Senate Bill 19-236, *Sunset Public Utilities Commission,* Section 13 (May 2019).

[xxxiii] Galen L Barbose, *U.S. Renewables Portfolio Standards: 2019 Annual Status Update*, Berkeley Lab, (July 2019).

[xxxiv] Heather Pohnan, Maggie Shober, and John D. Wilson, *Tracking Decarbonization in the Southeast: 2019 Generation + CO2 Emissions Report*, Southern Alliance for Clean Energy (July 2019); and Bruce Biewald et. al., *Investing in Failure: How Large Power Companies Are Undermining their Decarbonization Targets*, Synapse Energy Economics for Majority Action (March 2020).

[xxxv] See *United States v. E.I. du Pont de Nemours & Co.*, 351 U.S. 377, 391-92 (1956).

[xxxvi] The practices suggested here presume a market design and bidding process that is common across the United States. A wider range of potential procurement practices is discussed in IRENA, *Renewable Energy Auctions: A Guide to Design* (June 2015).

[xxxvii] Public Utilities Commission of Colorado, *Cheyenne Ridge Wind Project CPCN*, Decision No. C19-0367 (April 24, 2019), CoPUC Proceeding No. 18A-0905E, p. 13.

[xxxviii] North Carolina Utilities Commission, *2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans,* Order in Docket No. E-100, Sub 157 (August 27, 2019), p. 90-91.

[xxxix] Claire E. Kreycik et. al., *Procurement Options for New Renewable Electricity Supply*, National Renewable Energy Laboratory Technical Report NREL/TP-6A20-52983 (December 2011).

[xl] Maureen Lackner et al., "Policy Brief - Using Lessons from Reverse Auctions for Renewables to Deliver Energy Storage Capacity: Guidance for Policymakers," *Review of Environmental Economics and Policy*, (Winter 2019).

[xli] Susan Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, Analysis Group (July 2008).

[xlii] Ronald L. Lehr and Robert Touslee, "What Are We Bid? Stimulating Electric Generation Resources Through the Auction Method," *11 Public Utilities Fortnightly* (12 November 1987).

[xliii] Colorado Public Utilities Commission, *Amendments to Electric Rules, 4 CC 723-3*, Proceeding No. 19R-0096E.

[xliv] Colorado Public Utilities Commission, *2016 Electric Resource Plan Phase I*, Decision No. C17-0316 (March 23, 2017), Proceeding No. 16A-0396E, p. 15.

[xlv] Colorado Public Utilities Commission, *Phase II Decision*, Decision No. C18-0761 (August 27, 2018), Proceeding No. 16A-0396E, p. 16.

[xlvi] Colorado Public Utilities Commission, *2016 Electric Resource Plan Phase I*, Decision No. C17-0316 (March 23, 2017), Proceeding No. 16A-0396E, pp. 40-44.

[xlvii] Xcel Energy Colorado, *2016 Electric Resource Plan, 120-Day Report*, CoPUC Proceeding No. 16A-0396E (June 6, 2018), pp. 78, 84

[xlviii] Xcel Energy Colorado, *2016 Electric Resource Plan, 120-Day Report*, CoPUC Proceeding No. 16A-0396E (June 6, 2018), p. 41.

[xlix] Mark Detsky, *Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association*, GPSC Docket No. 42310 (April 25, 2019), pp. 21-22.

[l] Mark Detsky, *Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association*, GPSC Docket No. 42310 (April 25, 2019).

[li] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 52.

[lii] New Mexico Public Regulation Commission, *Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), pp. 6-7

[liii] One project, a 140 MW wind project, was separately proposed a month earlier in an RPS compliance action. Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00159-UT (June 3, 2019), p. 18.

[liv] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 15.

[lv] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), Exhibit RWN-4, p. 9.

[lvi] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 4, 33.

[lvii] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 8.

[lviii] Anna Sommer, *Corrected Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 13, 2020), p. 4; Justin Brant, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 27, 2020), pp. 5, 8; Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 24; Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 11, 56-57, 75-76, 81-82.

[lix] PNM contends that the CCAE portfolio would cost approximately $100 million more if modeling assumptions that it disagrees with are used. Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 23.

[lx] New Mexico Public Regulation Commission, *Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), pp. 6-7.

[lxi] New Mexico Public Regulation Commission*Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), p. 12.

[lxii] New Mexico Public Regulation Commission, *Corrected Order on Consolidated Application,* NMPRC Case Nos. 19-00018-UT and 19-00195-UT (July 10, 2019), pp. 2-5.

[lxiii] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 7-8.

[lxiv] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 8.

[lxv] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 16.

[lxvi] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 17.

[lxvii] Tyler Comings, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 13, 2020), p. 19.

[lxviii] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 23, 33-44.

[lxix] Nick Wintermantel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 22-24.

[lxx] William Kemp, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 23-29. Note that PNM has substantial control over the battery storage facilities. Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 68.

[lxxi] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (December 13, 2019), p. 23.

[lxxii] Tyler Comings, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 5.

[lxxiii] Nick Wintermantel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 23-25.

[lxxiv] Mihir Desu, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 20-25, 32-46.

[lxxv] New Mexico Public Regulation Commission, *Order Addressing Revised PNM Proposal on Discovery Issues*, NMPRC Case No. 19-00195-UT (August 27, 2019), p. 3.

[lxxvi] PNM estimated that the "total cost for modeling-related requests and software [was] $100,000." PNM testimony recommended that parties bear their own costs for this modeling in the future. (v Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 65.) The cost to PNM for a single EnCompass license (which can be shared by multiple parties) is $5,000, and for SERVM is $2,100 per month, per party. (PNM, *Revised Proposal to Provide Parties Access to Resource Planning Models and Information Regarding Requests for Proposals*, NMPRC Case No. 19-00195-UT (August 14, 2019), pp. 19-20.) Software license costs negotiated directly by individual parties could be significantly higher than those made available to PNM, and the software will also require purchase or rental of a compatible server environment.

[lxxvii] Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019).

[lxxviii] The capacity-based RFP will solicit bids for two separate capacity needs, one for 2022-23 and one for 2026-28. Originally proposed as two RFPs, Georgia Power has initiated a single RFP process titled "2022-2028 Capacity Request For Proposals." *See* Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019), Stipulation p. 4.

[lxxix] The "DG" RFP will procure customer-sited projects, paid avoided costs. If the RFP is oversubscribed, a lottery will be used to select projects. Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019), p. 15.

[lxxx] The details of the biomass RFP are not yet developed, but presumably this competitive procurement will not cap costs at avoided costs, as testimony during the hearing suggested that biomass would be too expensive. Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019), p. 15-16.

[lxxxi] Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019), Stipulation p. 5.

[lxxxii] Georgia Public Service Commission, Rule 515-3-4-.04(3).

[lxxxiii] Affiliate and turnkey projects were allowed in: Georgia Power, *2020/2021 Renewable Energy Development Initiative, Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), p. 16-18. Affiliate and self-build projects were allowed in: Georgia Power, *2015 Request for Proposals*, Georgia PSC Docket 27488 (April 20, 2010), p. 2, 4.

[lxxxiv] Jeffrey R. Grubb et. al., *Direct Testimony on behalf of Georgia Power Company*, GPSC Docket No. 42310 (March 14, 2019), p. 38.

[lxxxv] Georgia Power Company, *Application for Decertification, Certification and Updated Integrated Resource Plan*, GPSC Docket No. 34218 (August 4, 2011), p. 25.

[lxxxvi] Georgia Public Service Commission, *Order Approving 2018/19 Renewable Energy Development Initiative Power Purchase Agreements*, Docket No. 41596 (January 16, 2018), p. 3.

[lxxxvii] Jeffrey R. Grubb et. al., Direct Testimony on behalf of Georgia Power Company, GPSC Docket No. 42310 (March 14, 2019), p. 40.

[lxxxviii] Jeffrey R. Grubb et. al., Georgia Power 2019 Integrated Resource Plan, GPSC Docket No. 42310, transcript p. 222.

[lxxxix] Arne Olson, Direct Testimony on behalf of Georgia Large Scale Solar Association, GPSC Docket No. 42310 (April 25, 2019).

[xc] Arne Olson, Direct Testimony on behalf of Georgia Large Scale Solar Association, GPSC Docket No. 42310 (April 25, 2019), p. 53. Clarification relative to wind resources by personal communication.

[xci] Loutan, C., et al. Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant, California Independent System Operator, First Solar, and National Renewable Energy Laboratory, Report NREL/TP-5D00-67799 (March 2017).

[xcii] Energy and Environmental Economics, First Solar, and Tampa Electric Company, Investigating the Economic Value of Flexible Solar Plant Operation (October 2018), p. 4.

[xciii] Arne Olson, Direct Testimony on behalf of Georgia Large Scale Solar Association, GPSC Docket No. 42310 (April 25, 2019), p. 54.

[xciv] Jeffrey R. Grubb et. al., Georgia Power 2019 Integrated Resource Plan, GPSC Docket No. 42310, transcript p. 408, 411.

[xcv] Jeffrey R. Grubb et. al., Georgia Power 2019 Integrated Resource Plan, GPSC Docket No. 42310, transcript p. 564-566.

[xcvi] Jeffrey R. Grubb et. al., Georgia Power 2019 Integrated Resource Plan, GPSC Docket No. 42310, transcript p. 665.

[xcvii] Mark Detsky, Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association, GPSC Docket No. 42310 (April 25, 2019), p. 28.

[xcviii] Georgia Power, *2020/2021 Renewable Energy Development Initiative,* Request for Proposals for Utility Scale Renewable Generation, GPSC Docket No. 40706 (December 10, 2018), p. 2-3.

[xcix] Georgia Power*, A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia,* Integrated Resource Plan Technical Appendix Volume 2, GPSC Docket No. 42310 (January 17, 2019).

[c] Georgia Power*, A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia,* Integrated Resource Plan Technical Appendix Volume 2, GPSC Docket No. 42310 (January 17, 2019).

[ci] Jamie Barber et. al., Direct Testimony on Behalf of the Georgia Public Service Commission Public Interest Advocacy Staff, GPSC Docket No. 42310 (April 25, 2019), p. 48; Brendan J. Kirby, Direct Testimony on Behalf of Southern Alliance for Clean Energy, GPSC Docket No. 42310 (April 25, 2019), pp. 18-26; James F. Wilson, Direct Testimony on Behalf of Georgia Interfaith Power & Light and Partnership for Southern Equity, GPSC Docket No. 42310 (April 25, 2019), p. 30; and William M. Cox and Karl R. Rabago, Direct Testimony on Behalf of Georgia Solar Energy Association and Georgia Solar Energy Industries Association, GPSC Docket No. 42310 (April 25, 2019), p. 36-37.

[cii] Arne Olson, Direct Testimony on behalf of Georgia Large Scale Solar Association, GPSC Docket No. 42310 (April 25, 2019), p. 19.

[ciii] Georgia Power, 2015 Request for Proposals, GPSC Docket No. 27488 (April 20, 2010), Attachment G.

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EXHIBIT MDD-3

Docket No. 22-11032
Interwest Energy Alliance
Prefiled Direct Testimony of Mark Detsky, Esq.

Reimagining Resource Planning

Report / January 2023

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About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

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Study at a Glance

Chapter 1 Integrated Resource Planning Purpose and Overview	**Resource planning is a crucial opportunity for utilities, regulators, and stakeholders to shape the future electricity system.**
Chapter 2 Understanding How States Define Resource Planning Today	**The rules and guidelines that define resource planning vary across states and can be updated by regulators and legislators.** We review examples of how 12 states address three major questions: which utilities are required to do resource planning, whether and how the plans are reviewed, and how plans affect procurement.
Chapter 3 How to Reimagine Resource Planning	**IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions:** • **Trusted** — The integrated resource plan (IRP) is transparent and well vetted, with stakeholder input. • **Comprehensive** — The IRP can accurately represent the costs, capabilities, system impacts, and values of the resources that might be available within the planning time horizon, and can consider actions across the transmission and distribution systems as portfolio options. • **Aligned** — It is clear how the plan evaluates options to meet traditional planning requirements such as reliability, affordability, and safety as well as state and federal policies and customer priorities such as reducing emissions and advancing environmental justice. To holistically address the challenges facing planning today, regulators have an opportunity to proactively refine the **purpose, scope, roles,** and **tools** that support planning.
Chapters 4, 5, 6 Trusted, Comprehensive, Aligned	**Utilities and regulators can look to examples of enhancements across the country that utilities and regulators have tested in IRPs** to make sure plans are trusted, comprehensive, and aligned.
Chapter 7 Conclusion	**Utilities and regulators should use this opportunity to consider how resource planning may need to be "reimagined."**

Executive Summary

Opportunity to Improve Resource Planning

In this period of rapid change in the electricity sector, resource planning has never been more important — or more complex.

Planning represents an opportunity to shape a significant fraction of the future electricity system. Between now (2022) and the end of 2025, utilities serving at least 40% of US total electricity sales and over 90 million customers will file integrated resource plans.[i] Current utility resource plans show that utilities plan to invest over $300 billion in new resources over the next 15 years.

Utility integrated resource plans (IRPs) have historically been tools for utilities and regulators to determine the portfolio of generation and demand-side resources that can meet projected peak and energy demand over the next 10 to 30 years at least cost, while mitigating risk and meeting policy objectives. The outputs of the plan are intended to inform a utility's resource procurement, power purchasing, and program decisions — driving accountability toward a portfolio that results in affordable rates and maintains a safe and reliable grid.

Yet much of the value in resource planning is not in definitively determining the utility's portfolio 30 years out, but in the exercise of planning. Resource planning presents a crucial opportunity for utilities, regulators, and stakeholders to:

- Understand the energy needs of the households, communities, and businesses a utility serves, as well as how they will change over time, and translate them into system needs
- Establish a common set of assumptions and evidence that can be used to assess which near- and long-term options can meet system needs and achieve desired utility performance across multiple objectives
- Identify longer-term risks and opportunities and strategies to navigate them

Challenges of Planning for an Uncertain Future during a Period of Rapid Change

We observe that IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions, as outlined in Exhibit 1 (next page).

---

i This is based on RMI analysis of EQ Research data from September 2022 that summarizes the total proposed resources for investment across 104 utility IRPs plus US Energy Information Administration (EIA) data for total annual sales.

Exhibit 1 **Core IRP qualities and why they're important to utilities and regulators**

IRP quality	Definition	Why quality is important to regulators	Why quality is important to utilities
Trusted	The IRP is transparent and well vetted, with stakeholder input.	When resource plans are trusted, regulators can use them as evidence that future investments are prudent and in the public interest.	When utilities seek input from their customers and engender trust in their assumptions, they can develop an accurate plan that meets customer energy needs and leads to regulatory approval.
Comprehensive	The IRP can accurately represent the costs, capabilities, system impacts, and values of resources that might be available within the planning time horizon; the IRP can consider actions across the transmission and distribution systems as portfolio options.	When plans are comprehensive, regulators can ensure that options to best serve customers have been surfaced and tested.	When plans are comprehensive, utilities can adequately assess the value and risk of their potential future investments.
Aligned	It is clear how the plan evaluates options to meet traditional planning requirements such as reliability, affordability, and safety, as well as state and federal policies and customer priorities, such as reducing emissions and advancing environmental justice.	When plans are aligned, regulators can assess whether the recommended portfolio can perform across the range of performance outcomes within their mandate.	When utilities demonstrate that plans are aligned with policy objectives, they can avoid future disallowance of investments and under- or over-procurement of resources.

Source: RMI

Today, a few major trends are adding urgency and complexity to the IRP process, including but not limited to:

- Rapid technology change and shifting resource costs
- A range of new state and federal policies that expand planning objectives beyond affordability, reliability, and safety to include emissions reductions, advancement of environmental justice, economic development, and support of electrification of transportation, buildings, and industry
- Increasing recognition that decisions made on distribution and transmission systems affect generation resource planning and vice versa
- Increasing stakeholder awareness that resource planning can have an impact on local air quality, health, jobs, energy bills, and climate change

If an IRP does not achieve these three qualities, its credibility, accuracy, and effectiveness may be eroded. The risks of unanticipated costs for ratepayers, disallowed future investments, dissatisfied customers, and failure to meet public policy objectives will increase.

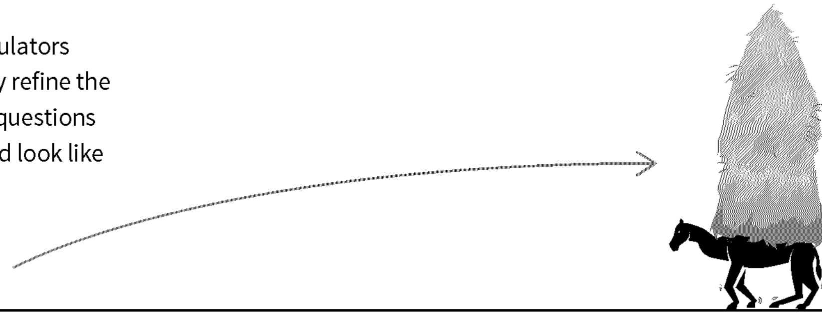
Expanding Scope for Resource Planning

Updating the IRP process to ensure that it remains trusted, comprehensive, and aligned can make IRPs more complex. As such, making changes around the edges or adding new IRP requirements may no longer be what best serves a utility or regulator — especially with staff time and capacity constraints. To use a metaphor to guide our thinking, the goal is to avoid amassing incremental IRP expectations in a way that is like the straw that breaks the camel's back (Exhibit 2, next page).

Exhibit 2 **How new expectations might challenge the IRP process**

To address these challenges more holistically, regulators have an opportunity to proactively and repeatedly refine the purpose, scope, roles, and tools — and to ask big questions about what the next generation of planning should look like — before making piecemeal enhancements.

New IRP expectations

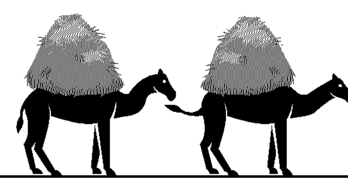


Purpose

Regulators and state policymakers have an opportunity to take a step back and clearly articulate goals for the electricity system over the next few decades and how the utility's options for future investment should be evaluated with respect to those goals. With clear goals and an updated framework for making decisions across multiple goals, the information that is needed to make decisions, which should be included in a plan, should become clearer.

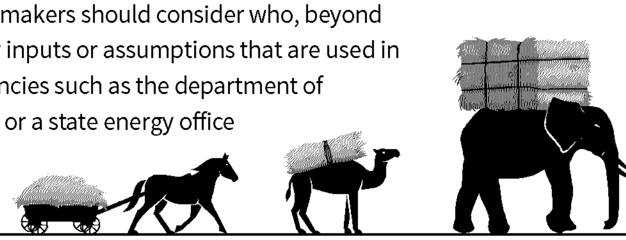
Scope

Once the information needed to make decisions is clear, regulators and state policymakers have an opportunity to reevaluate the specific scope of utility resource planning. Instead of adding more requirements to the IRP, there is an opportunity to define additional planning activities with their own objectives, and the links among them. Defining new, separate planning activities is a good option when specific decisions need to happen more or less frequently than an IRP or require more granular or more broad information. For example, regulators or policymakers may identify a need to create a separate distribution system planning process, an economy-wide decarbonization process, or an additional plan that tracks annual progress toward climate targets.



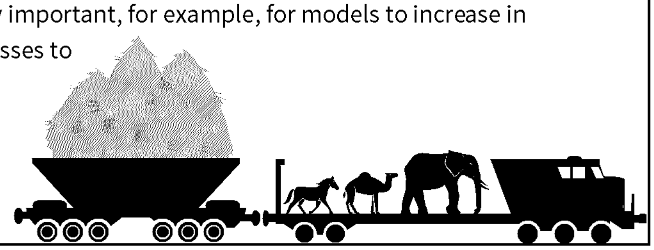
Roles

When clarifying the scope of IRP and other planning activities, state policymakers should consider who, beyond the utility or regulatory staff in the IRP process, might provide or verify key inputs or assumptions that are used in the IRP to maintain accuracy, credibility, and trust. For example, state agencies such as the department of transportation may be able to provide electric vehicle growth projections, or a state energy office might conduct a deep decarbonization study whose assumptions are used in an IRP.



Tools

Finally, the application of analytical tools and engagement processes that support resource planning need to be designed to be flexible, transparent, and continuously improved. It will be increasingly important, for example, for models to increase in computational ability and incorporate new technologies, and for processes to support utilities in meaningfully engaging stakeholders and in getting accurate market information (e.g., through consistent industry engagement and competitive solicitations). Effective tools and processes can reduce some of the friction in today's planning.

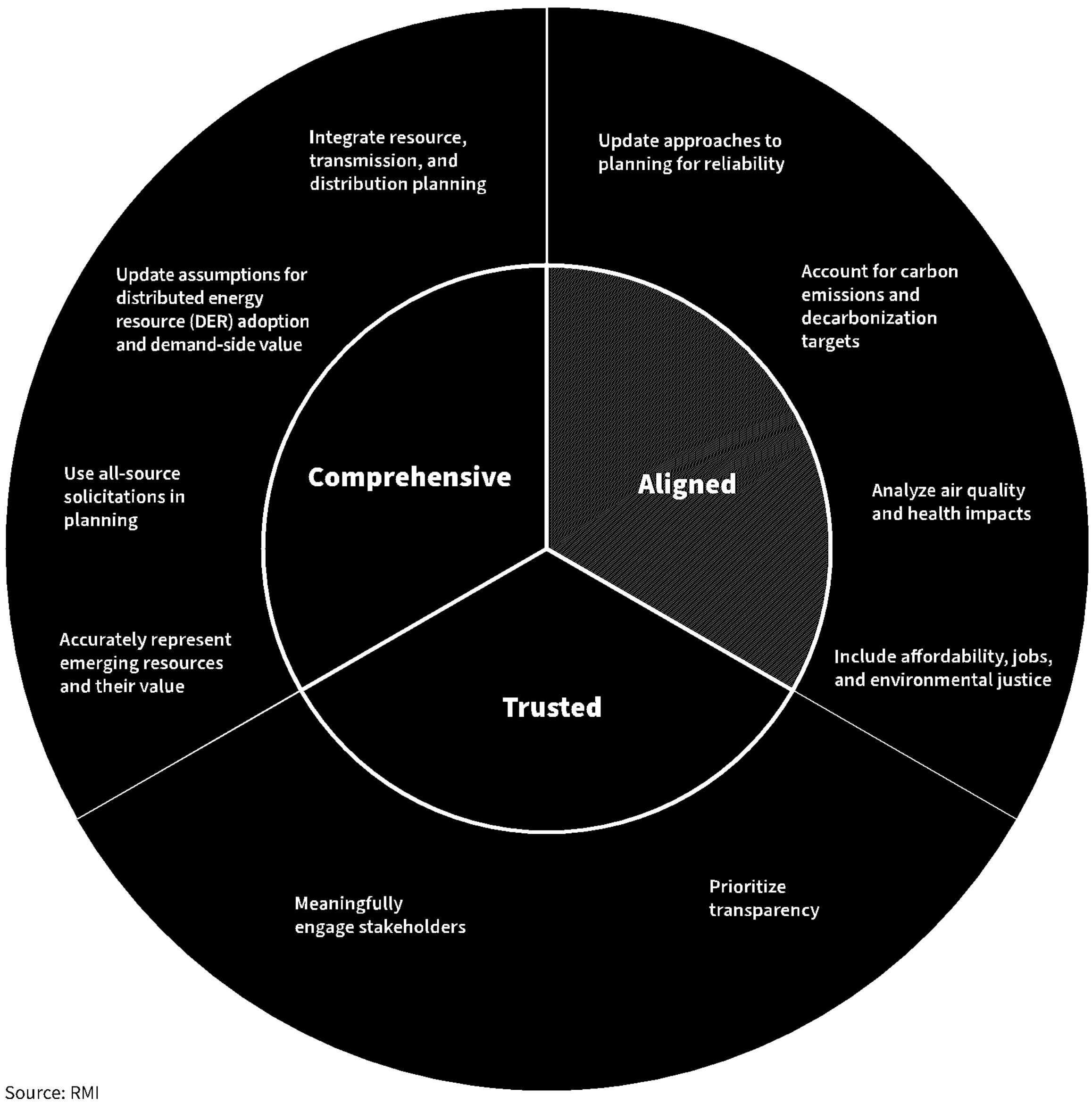


Source: RMI

Overview of Planning Enhancements

After aligning on a set of priority changes, utilities and regulators can look to approaches that have been tested in IRPs across the country that can "enhance" plans to be more trusted, comprehensive, and aligned. These enhancements are summarized in Exhibit 3.

Exhibit 3 **Options to enhance resource planning**



Source: RMI

To build **trust** in resource plans, regulators and utilities are:

- **Prioritizing transparency,** by updating rules that assess what information may be held as confidential or proprietary — and applying those rules to ensure that stakeholders have the information they need to engage effectively in the IRP process

- **Meaningfully engaging stakeholders,** with an inclusive and substantive process for input before and during the plan's development

To make plans more **comprehensive,** regulators and utilities are:

- **Integrating resource, transmission, and distribution system planning,** to better understand how decisions at one level of the grid might affect others

- **Using all-source solicitations in the planning process,** to bring in timely market data as a basis for making procurement decisions

- **Updating assumptions and modeling tools for distributed energy resources (DER) adoption and value,** to more accurately forecast DER growth patterns and impacts and assess DER costs and benefits

- **Accurately representing emerging resources and their value,** by including all options that may be commercially available in the planning horizon and using models with a level of spatial and temporal granularity needed to reveal values

To **align** resource plans with evolving objectives and understand the impacts of plans on people, regulators and utilities are:

- **Updating approaches to planning for reliability,** to better understand the risks, vulnerabilities, and types of solutions that can contribute to reliability, including resource adequacy and resilience

- **Accounting for carbon emissions and decarbonization targets,** to assess progress and alignment toward climate goals or better understand the risk of future climate policy

- **Analyzing health and air quality impacts** across resource options and portfolios

- **Including affordability, jobs, and environmental justice,** to make the human impacts of planning clearer

Reimagining Resource Planning

Ultimately, we hope that utilities and regulators will use this opportunity — when their resource planning processes are being stretched and challenged — to consider how resource planning may need to be more radically reimagined.

1. Integrated Resource Planning Purpose and Overview

This chapter provides a basic overview of integrated resource planning for readers unfamiliar with the key elements of resource planning, specifies who conducts resource planning, and explains why most states require utilities to conduct resource planning.

Utility IRPs have historically been tools for utilities and regulators to determine the portfolio of generation and demand-side resources that can meet projected peak and energy demand over a determined planning horizon at least cost, while mitigating risk and meeting policy objectives. This portfolio is intended to inform a utility's resource decisions — driving accountability toward actions that result in affordable rates and desired utility performance. Typically, IRPs have a planning horizon of 10 to 30 years, and utilities file new plans every two to five years.

Some IRPs conclude with a near-term action plan, commonly two to five years, outlining the utility's plan for investments, procurement processes, and customer programs as it moves toward the preferred portfolio. Even if IRPs are not decisional (see Exhibit 11, page 27), they are often used as a primary source of data and analysis that informs decision-making by regulators and utilities in other areas such as procurement, program design, and ratemaking.

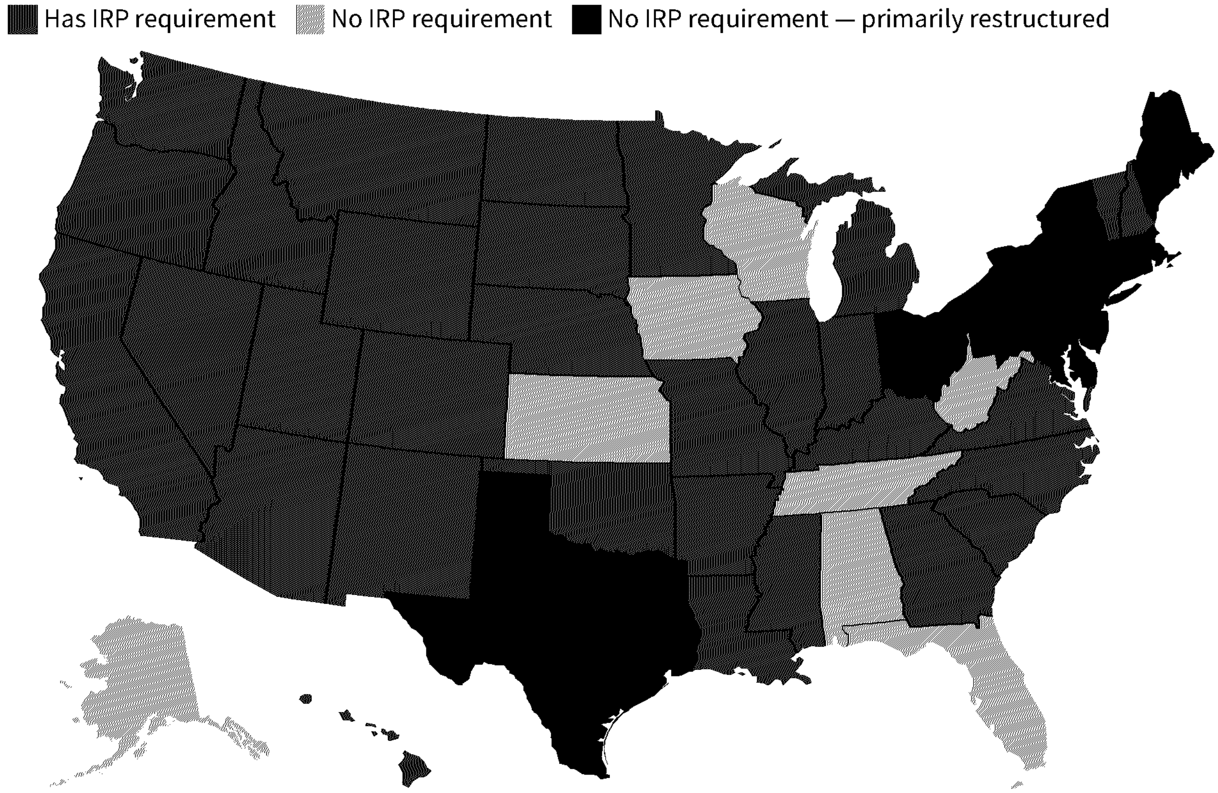
Resource planning requirements are determined by state, as summarized in Exhibit 4 (next page). Of the 19 states that have no formal utility planning requirement, most are in primarily restructured states where the mix of resources is largely determined by market dynamics rather than utility plans.[ii] Additionally, in some of those states (e.g., Connecticut), state energy offices or regulators undertake their own IRP process. Utilities that span multiple states must comply with the IRP requirements of each state within its territory.

Of the states depicted in Exhibit 4 (next page) with no planning requirements, utilities may still do long-term planning. In Florida, utilities file annual 10-year site plans.[1] Although Tennessee does not have an IRP requirement, the federal government requires the Tennessee Valley Authority to conduct an IRP.

ii "Primarily restructured" refers to states that are within a market footprint and have the majority of the state's generating capacity owned by entities other than electric utilities, according to EIA Form 860.

Exhibit 4

Planning requirements by state



Source: US Environmental Protection Agency, *State Energy and Environment Guide to Action: Resource Planning and Procurement*, Figure 2; RMI analysis of EIA-860M to add distinction for primarily restructured states

Absent clear state guidelines, utilities often still do some form of long-term planning because the exercise is essential to maintaining a safe, reliable, and affordable electricity system.

The Scale of IRPs and Their Impact

Resource plans present a massive opportunity to shape investments in our future electricity system. In the next three years, utilities representing about 40% of total US energy sales will file IRPs.[iii] Current utility resource plans show over $300 billion of projected new investments by 2035 — investments that will have an impact on the affordability of energy bills, health and jobs in our communities, and the ability to meet carbon targets.[iv]

iii RMI analysis of EQ Research's monthly published data for September 2022, filtered for utilities that are expected to file resource plans before the end of 2025 with total annual sales from EIA.

iv RMI analysis of EQ Research's monthly published data for September 2022, across all 104 utilities' resource plans on record. Data on total capacity additions per year was combined with resource costs from the National Renewable Energy Laboratory (NREL) *2022 Annual Technology Baseline* to estimate projected investment.

An analysis of utility resource plans on record in September 2022 for 104 utilities, shared in Exhibit 5, shows that by 2035 utilities currently plan to:

- Build about 200 gigawatts (GW) of renewables, including solar, wind, geothermal, and new hydro
- Build 44 GW of battery and pumped hydro storage
- Deploy 11 GW of demand-side management
- Build 61 GW of gas power plants
- Retire 74 GW of fossil fuel–fired power plants, including coal, gas, and oil
- Retire 6 GW of nuclear and build nearly 2 GW of new nuclear

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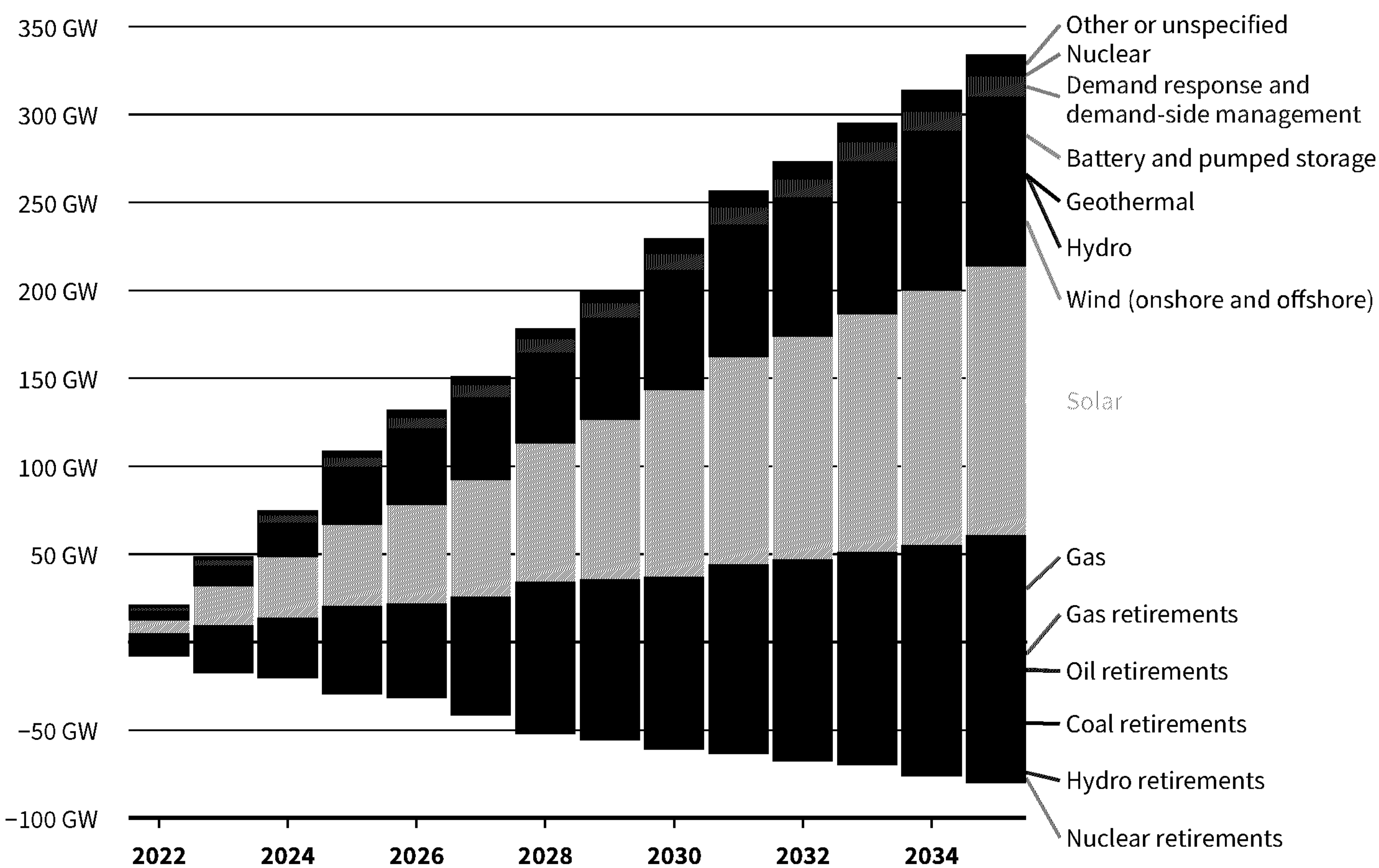
Exhibit 5 **Cumulative capacity of projected retirements and additions in 104 utility resource plans, September 2022**

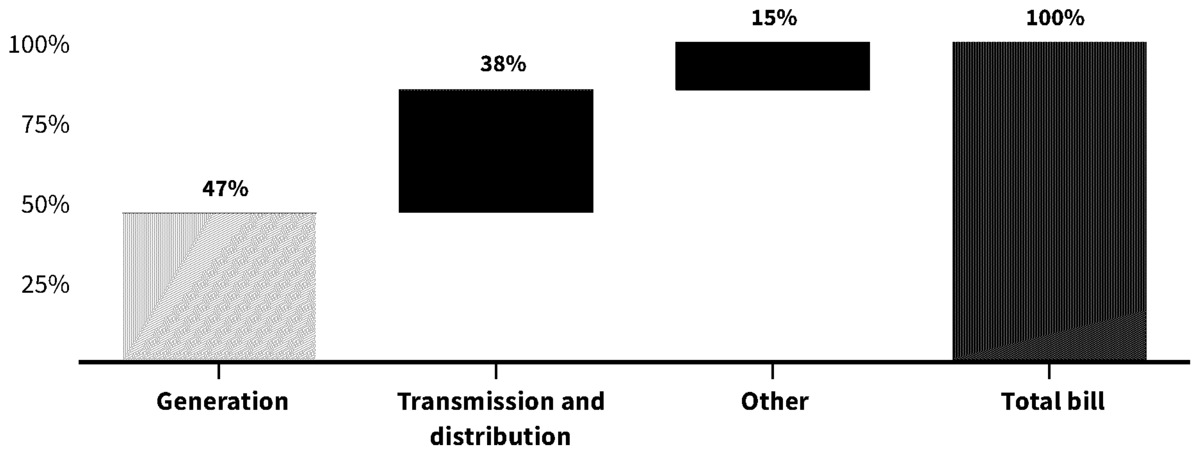


Source: RMI analysis of EQ Research data as of September 2022

The portfolios prioritized in resource planning eventually become capital investments, power purchases, administrative costs, and operations and fuel costs that affect customers' bills. In 2020, generation including purchased power accounted for 47% of customers' bills, as seen in Exhibit 6.

Exhibit 6

Components of a residential customer electricity bill



Note: The Utility Transition Hub calculates all utility expenses that are passed on to customers including both capital and operational costs by technology, based on data from FERC Form 1 and EIA Form 861. Here, we aggregated the approximate contribution to bills by resource type into three categories: generation; transmission and distribution; and other (e.g., administrative expenses). Data and documentation can be found on the **Utility Transition Hub**.

Source: RMI analysis of Federal Energy Regulatory Commission (FERC) Form 1 data, as shared in the **Utility Transition Hub**

As options for investment in transmission and distribution become increasingly integrated with resource planning processes, resource planning may present an opportunity to influence 85% or more of future bills.

Benefits of Resource Planning

Much of the value in resource planning is not in definitively determining the utility's portfolio in 10 to 30 years, but in the exercise of planning itself. The resource planning process presents a crucial opportunity for utilities, regulators, and stakeholders to:

- Understand the needs of the households, communities, and businesses that a utility serves, and how they will change over time
- Establish a common set of assumptions and evidence that can be used to assess which near- and long-term options can meet system needs and achieve desired utility performance across multiple objectives
- Identify longer-term risks and opportunities and align on strategies to navigate them

The outcomes of several recent utility planning processes have demonstrated that they can be valuable in continuously challenging past assumptions, discovering more affordable and beneficial investment pathways, or identifying new long-term risks. For example:

- In Xcel Energy's *2016–2030 Upper Midwest Resource Plan*, the utility proposed building a combined cycle gas-fired power plant to replace a retiring coal unit.[2] Stakeholders engaged extensively in the IRP with comments and testimony challenging the assumption that new gas was the best option to meet the identified need. Xcel redid its analysis in its 2020–34 resource plan and proposed instead building smaller combustion turbines and more renewable energy. This alternative plan is projected to save $372 million (present value of societal costs) and accelerate the timeline for meeting carbon reduction targets.[3]

- Duke Energy Indiana's 2021 preferred resource portfolio plans for less gas and more renewables relative to its 2019 portfolio, including adding hybrid solar and storage facilities for the first time. In 2019, Duke proposed a total of 2.4 GW of new combined cycle gas by 2034 and 1.6 GW of solar by 2037.[4] Two years later, the preferred portfolio planned for 50% less new combined cycle gas (1.2 GW), more than 1.5 times as much solar by 2037 (2.57 GW), and 1.1 GW of hybrid solar and storage.[5] Without this iterative approach with updated technology costs and capabilities, Duke might have otherwise built unnecessary assets and delayed progress toward its company emissions reduction targets.

- The Georgia Power IRP process has a robust stakeholder ecosystem with nearly 20 parties engaged in each three-year planning cycle. Over the past few cycles, the Georgia Public Service Commission has added more renewable resources than the previous IRP. In 2022, the PSC approved 2.3 GW of utility-scale renewables and 500 megawatts (MW) of battery storage, along with several short-term natural gas power purchase agreements.[6] This is nearly a 200% increase from its 2016 IRP, in which Georgia Power proposed 525 MW of renewables from requests for proposals (RFPs) or customer-sited projects and a slight increase from its 2019 proposal of 2.0 GW of utility-scale solar and 216 MW of customer-sited solar generation.[7]

Process of Developing an IRP

As much of the value in an IRP is in the exercise of planning, defining a clear and robust process is critical. IRP processes vary based on factors such as type of utility, regulatory guidelines or requirements for planning, and the size of the utility and resource planning team. Most include the core pieces depicted in Exhibit 7 (next page).[8]

Exhibit 7 **Building blocks of an IRP process**

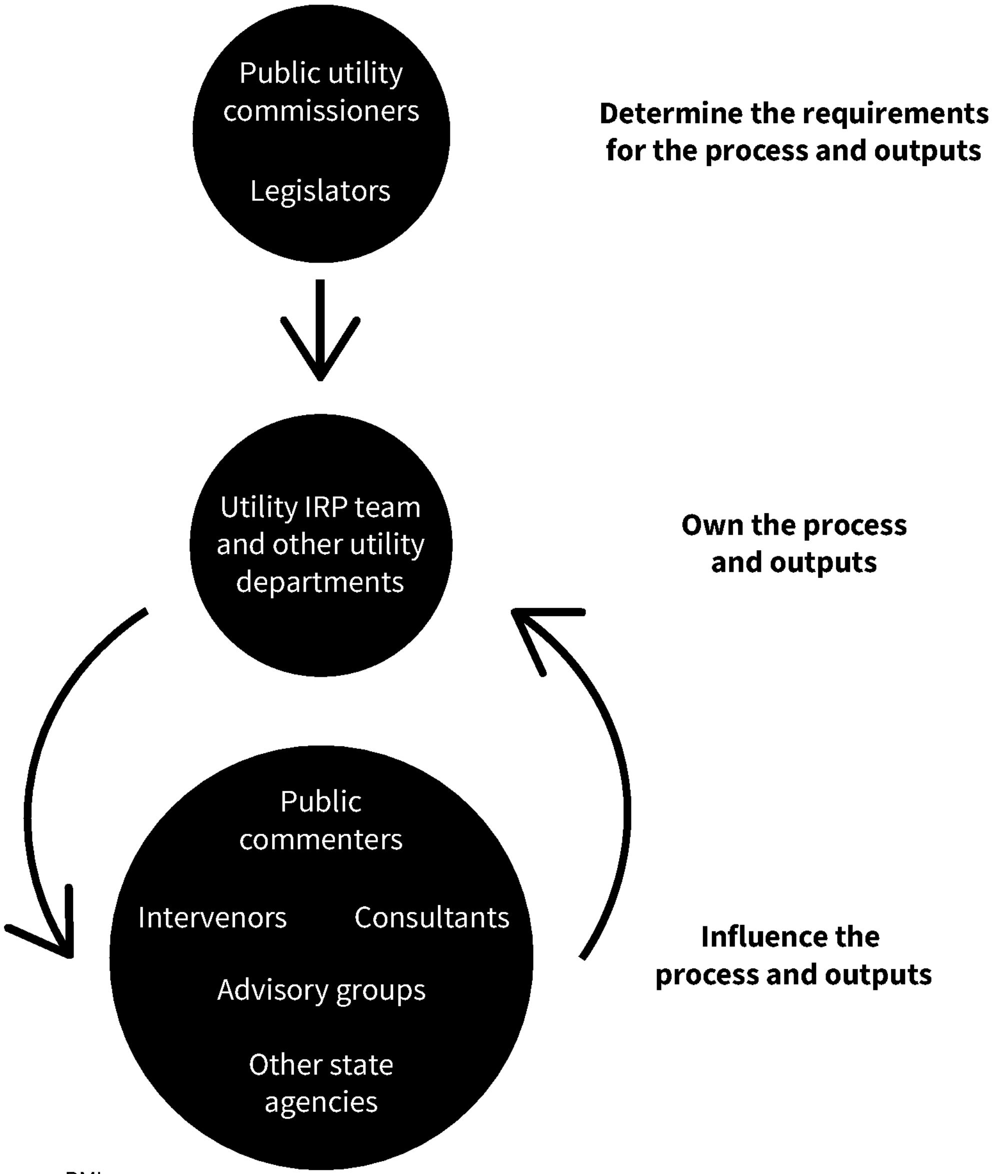
Source: "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Each of the steps varies in detail and complexity by utility, and some of these steps may occur simultaneously or in a different order, or be iterative. Many IRP processes include stakeholder engagement before or during the development of the IRP concurrent with these steps.

Key Actors in Resource Planning

Most of the examples of robust planning processes that are included in this report involve an ecosystem of actors beyond the utility. Who these actors are and how they influence the development of a resource plan are summarized in Exhibit 8 (next page).

Exhibit 8 **Stakeholders typically involved in developing a resource plan**



Source: RMI

Utilities are typically the owners of resource plans, because ultimately it is their responsibility to maintain the electricity system in line with established state and federal standards of performance. Usually, a designated team within the utility will lead the process of developing and publishing the IRP. This includes consolidating data, running analyses, engaging with stakeholders, and writing the plan. Other departments within the utility, such as regulatory affairs, financial planning, engineering, and operations, also are involved in developing a resource plan.

The public utility commission (PUC) outlines guidelines and/or requirements for resource planning. These typically address procedural elements of the planning process (e.g., who is involved, how frequently the plan is filed, opportunities for comment, and how the plan is evaluated) and substantive requirements for what should be included in the plan.

Some state statutes are specific about the role of the commission in resource planning, including the Georgia Code, which specifically outlines that the commission should require, review, and approve IRPs.[9] In many states, statute or authority for resource planning is not so specific, and the commission has further clarified its role through rulemaking or by building precedent through specific orders. For example, after a 2019 statute required the Colorado PUC to expand its resource planning purview to include cooperatively owned generation and transmission utilities, the commission followed with a Notice of Proposed Rulemaking to clarify and formalize requirements and its role.[10]

Consultants, public commenters, advisory groups, intervenors, consumer advocates, and other state agencies may also have roles in resource planning. Some utilities hire consultants to help with tasks such as modeling, stakeholder engagement, supportive studies, and technical writing. Utilities may incorporate input from public commenters or advisory groups, and in some states, specific types of engagement are required by the commission. In most states, intervenors in an IRP proceeding can submit comments that include requests for additional information from the utility, alternative analysis, critiques of the process, or statements of their constituents' needs from the resource plan.[v] In a formal, contested proceeding, comments are supplemented with testimony and can help get additional information and input on the record for the commission to consider in its IRP decision.

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v Proceeding, in this context, means a quasi-judicial or quasi-legislative case administered by a public utilities commission. Typically, IRP proceedings will either be contested cases or investigations. For more information on types of proceedings, see *Regulatory Process Design for Decarbonization, Equity, and Innovation*, **https://rmi.org/wp-content/uploads/dlm_uploads/2022/07/regulatory_process_design_for_decarbonization_equity_and_innovation.pdf**.

2. Understanding How States Define Resource Planning Today

In many states, legislators and regulators have defined more prescriptive rules or guidelines that govern resource planning. IRP rules and guidelines typically consist of procedural requirements that govern how planning should be conducted, and content requirements for what should be included in a filed IRP. Utilities may still engage in planning without IRP requirements.

Most states with a set of prescriptive planning rules have sought to define the following procedural requirements governing how planning is conducted:

- **Which utilities submit IRPs** determines whether there is a recurring, formal planning process that provides regulators with visibility into utility plans. Where the IRP opens a contested case, plans are formally submitted in the public record.
- **How IRPs are reviewed, accepted, acknowledged, approved, or denied** determines how much of an influence the commission, staff, and other stakeholders engaged in IRPs have to provide input into or recommendations about planning.
- **To what extent IRP outcomes are tied to procurement decisions** can determine how influential the planning process is in specifying a portfolio for investment.

In this chapter, we map how 12 states have defined these three sets of procedural requirements in their resource planning rules. The 12 states we've chosen represent diverse geographic and regulatory contexts. Collectively, these examples highlight the range of resource planning requirements today and expose where and how legislators or regulators might consider providing more clarity or direction to improve the planning processes.

We do not cover the content requirements for what should be included in IRPs across states in this chapter. Although rules or guidelines typically require the basic information described in Chapter 1, the exact requirements and degree of detail vary significantly across states. In Chapters 4, 5, and 6, where we describe options to enhance resource planning, we highlight relevant examples of content rules or guidelines. For additional context and sources for the information included in this chapter, please see *Appendix: Resource Tables*.

Which Utilities Must Submit IRPs

Which utilities are required to submit IRPs varies by state rules and statutes. Most commonly, investor-owned utilities are required to submit IRPs. In a few states, IRP requirements extend beyond investor-owned utilities, such as in South Carolina, where electric cooperatives, municipally owned electric utilities, and the South Carolina Public Service Authority must prepare IRPs to submit to the state energy office (see Exhibit 9 on the next page for more examples). Some jurisdictions do not have specific requirements for which utilities are required to submit IRPs. For example, in Wyoming, only utilities filing IRPs in other jurisdictions must file their plans to the commission.

Municipal, cooperative, or federally owned utilities may have additional requirements for resource planning that are set by the city, the board, or the federal government. For example, some federal power marketing agencies, such as the Western Area Power Administration and Tennessee Valley Authority, require utilities that purchase federal power from them to submit IRPs.[11]

Exhibit 9 **Which utilities must file IRPs vary across 12 states**

No IRP requirement

Alabama: Alabama has no IRP requirements, but Alabama Power voluntarily submits a plan every three years for review.

Wyoming: Utilities filing IRPs in other jurisdictions must file one in Wyoming.

Some utilities

Utah: Applicable to Rocky Mountain Power.*

North Carolina: Applicable to Duke Energy Progress, Duke Energy Carolinas, Dominion every two years.

Georgia
- Each utility in the state whose rates are fixed by the Public Service Commission is required to file an integrated resource plan every three years.
- With the IRP, utilities also must file applications for building new plants, purchasing power, and demand-side expenditures.

Oregon: All investor-owned utilities are required to submit resource plans every two years after the previous IRP acknowledgment.

Michigan
- Each rate-regulated utility in the state is required to file an IRP at least every five years.
- Utilities with fewer than 1 million customers in the state can request a waiver for a portion of the requirements.
- Multistate utilities may file using other states' requirements, but the commission can request additional information.

New Mexico
- Public utilities supplying electric service to customers file an IRP, along with an action plan, with the commission every three years.
- Does not include distribution cooperatives.

All utilities

Minnesota
- Applicable to all utilities generating 100,000 kilowatts or more of electric power and serving, either directly or indirectly, 10,000+ retail customers in Minnesota every two years.
- The commission's order is advisory for cooperative and municipal utilities, rather than decisional.
- Some generation and transmission co-ops may file an optional IRP, and the commission can also make an advisory order.

Washington
- All utilities with more than 25,000 customers must develop IRPs.
- Investor-owned utilities submit plans to the commission.
- Consumer-owned utilities submit plans to the Department of Commerce.

Colorado
- Jurisdictional utilities, cooperative utilities, and transmission associations file resource plans to the commission every four years.
- Jurisdictional utilities and cooperative utilities have different sets of planning requirements.

South Carolina
- Electric utilities, electric cooperatives, municipally owned electric utilities, and the South Carolina Public Service Authority must each prepare an IRP.
- Each electric utility must submit its IRP to the commission.
- Electric cooperatives, municipally owned electric utilities, and the South Carolina Public Service Authority submit IRPs to the State Energy Office.**

* IRPs are most commonly applicable to investor-owned utilities (IOUs) and submitted to state PUCs.
** In some states, state energy offices review municipal and cooperative utility IRPs.

Source: RMI analysis; see *Appendix: Resource Tables* for additional context and sources

How IRPs Are Reviewed and Approved

In most states, the commission accepts, acknowledges, approves, or denies an IRP. The commission may acknowledge or approve the IRP with modifications and exceptions, as well as requirements for the next planning cycle. The terms "approval" and "acknowledgment" vary across states. "Approval" is more commonly used when the IRP is contested and the IRP decision authorizes a procurement outcome or tentative approval for cost recovery (see Exhibit 11, page 27). "Acknowledgment" typically defers the commission's judgment of the prudence of a proposed action to a certificate of public convenience and necessity (CPCN) or a rate case.

Many states require formal review of an IRP by the commission through a required hearing or along with an opportunity for public comment (see Exhibit 10, next page). For example, in South Carolina, the commission is required to open a proceeding to review the IRP and allow intervention from interested parties and reasonable discovery. Following this proceeding, the PUC must approve, modify, or deny the plan. In Oregon, the PUC considers public comments and recommendations in an established public meeting and then acknowledges the IRP through an order. In addition to the requirement for a public meeting, the proceeding includes rounds of review and comments among the utility, staff, and intervenors. In Utah, rules state that the public, state agencies, and other interested parties should have the opportunity to make formal comments.

Other states have fewer requirements for how the commission engages with filed IRPs. In North Carolina, the rules state that hearings are to be scheduled at the discretion of the commission, and the scope is explicitly limited to covering issues identified by the commission. In Wyoming, the commission's advisory staff is directed to review the IRP and draft a memo to report the findings to the commission in an open meeting or a technical conference. No further action is required, but the commission may accept the IRP as meeting the filing requirements.

Exhibit 10 **How the commission is required to review IRPs in 12 states**

Staff or the commission reviews and accepts

Alabama
- The IRP is reviewed with commission staff. The commission is not required to approve the resource plan.

Wyoming
- Commission advisory staff reviews the IRP as directed by the commission and drafts a memo to report its findings to the commission in an open meeting or technical conference.
- Review includes whether or not there was an opportunity for public comment.

North Carolina
- A hearing may be scheduled at the discretion of the commission, but an evidentiary hearing is not required.
- Public staff or intervenors may file comments or alternative plans.
- The commission typically issues an order to accept the plan as fit for future planning or request modifications.
- The commission has to report progress toward the plan to the state executive and legislative branches.

Commission acknowledges or requests modification, after seeking public input

Oregon
- The commission acknowledges IRP through an order after an uncontested proceeding and may request revisions before acknowledgment.
- The commission must consider comments and recommendations from a public meeting first.
- The public will be allowed significant involvement in the preparation of the IRP, including requests for information.

Utah
- The public, state agencies and other interested parties will have the opportunity to make formal comments. Formal hearings are not required but might be appropriate.
- The commission will review the plan and the merits of public comments and return the IRP for further work if needed.

New Mexico
- The commission reviews the IRP and accepts it or returns it with instructions for refiling, considering both the application and public comments in its review. It may open an investigation.
- A public comment period is required, and utilities are also required to respond to all public comments or explain why they were not addressed when the comment period concludes.
- Review and acceptance of the IRP is contingent not only on contents, but whether utilities followed public advisory process requirements including a yearlong series of meetings for public input.

Washington
- Utilities submit IRPs and clean energy action plans that are targeted toward 10-year progress for meeting state decarbonization targets.
- Public comment is required after draft IRPs are filed, and rules require IRP advisory groups.
- IRPs are acknowledged, with modifications that might affect the next clean energy implementation plan or action plan. Clean energy implementation plans are filed separately.
- Clean energy implementation plans are approved, rejected, or approved with conditions through a contested proceeding.

Minnesota
- The commission shall approve, reject, or modify the plan of a public utility consistent with the public interest.
- The case is conducted in an uncontested proceeding, allowing intervention, information requests, proposed. alternative plans, and written comments.
- The commission makes its decision based on the record, including response to information requests.

Commission approves, requests modification, or denies after a formal proceeding

Michigan
- The commission issues a final, appealable order approving or denying the plan.
- In a contested case proceeding, the commission shall review the IRP and allow intervention.
- The commission must seek an advisory opinion from the Department of Environment, Great Lakes, and Energy on whether the plan will increase air pollution and may invite other state agencies to provide testimony.

Georgia
- The commission will approve the utility's IRP, approve it subject to stated conditions, approve it with modifications, approve it in part and reject it in part, reject the utility's resource plan, as filed, or provide an alternative plan, upon determining, after a hearing is conducted, that this action is in the public interest.
- Must file an amendment if required before the next plan if there are impacts to a potential IRP or CPCN.

South Carolina
- The commission is required to open a proceeding to review IRPs, allowing intervention by interested parties and reasonable discovery.
- The commission needs to approve, modify, or deny the plan.

Colorado
- The commission may hold a hearing to review and render a decision.
- The commission will issue a written decision approving, disapproving, or ordering modification to the utility's plan, and the utility must implement modifications.

Source: RMI analysis; see *Appendix: Resource Tables* for additional context and sources

How Planning Relates to Procurement Decisions

IRP rules also typically define how influential IRPs are in resource procurement decisions.

In a few states, the acknowledgment or approval of an IRP directly authorizes resource procurement, meaning the utility can proceed with investments based on the outcome of the plan. In Georgia, if the commission approves an IRP, the utility is then required to issue a competitive solicitation for each type and quantity of supply-side resource in the approved plan.[12] In Minnesota, if the commission approves a proposed facility in a resource plan, a separate proceeding for certificate of public need and convenience may not be required.

In Washington and Colorado, approval of the IRP authorizes utilities to proceed with issuing an all-source solicitation for the identified need, rather than authorizing specific resources.

In other cases, acknowledgment of an IRP does not authorize procurement or guarantee any favorable ratemaking (i.e., all investments are still subject to an applicable prudence review) but is required to support the justification for new acquisitions. In Oregon, for example, requests for proposal must include "the alignment of the electric company's resource need addressed by the RFP with an identified need in an acknowledged IRP or subsequently identified need or change in circumstances with good cause shown."[13] Similarly, South Carolina and North Carolina also state in their rules that applications for new resources should reference a need determined in resource plans.

Exhibit 11 **How acknowledgment or approval of an IRP relates to procurement in 12 states**

Acknowledgment/ approval does not authorize procurement

Wyoming and Alabama: There is no formal approval or acknowledgment, and therefore no procurement implications.

Utah: Acknowledgment of an acceptable plan will not guarantee favorable ratemaking treatment of future resource acquisitions.

New Mexico: An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.

South Carolina

- The approval of a resource plan shall not be determinative of the reasonableness or prudence of the acquisition of any resource.
- Investment decisions may require demonstration that a facility is consistent with an approved resource plan.

North Carolina: Applications for resource acquisitions require reference to the need in an IRP.

Oregon

- Acknowledgment does not constitute guarantee of favorable ratemaking.
- Requests for proposals filed with the commission must be justified by a resource need in an acknowledged IRP.

Acknowlegment/ approval authorizes procurement of specific resources

Minnesota

- If a resource is to be built before the next resource plan, the IRP is treated as a CPCN for that resource.
- If the commission approves a proposed facility in the resource plan, a separate certificate of need proceeding is not required.

Michigan

- In approving an IRP, the commission specifies the costs approved for investment in new generation, power purchase agreements, or other investments.
- Utilities are required to conduct pre-RFP requests for proposals to source bids to consider in the planning process.

Georgia

- The utility is required to issue an RFP for each block of supply-side resources identified in the IRP.
- For the 2029–2031 time frame, the utility should use an all-source RFP to meet projected needs.

Acknowledgment/ approval authorizes all-source procurement

Washington: A utility must issue an all-source RFP if the IRP demonstrates that the utility has a resource need within four years.

Colorado

- The Phase I ERP (electric resource planning) decision requires approving an all-source RFP for the utility to issue.
- A commission decision approving the components of a utility's plan creates a presumption that utility actions consistent with that approval are prudent.

Source: RMI analysis; see *Appendix: Resource Tables* for additional context and sources

How States Are Evolving Requirements for Resource Planning

Resource planning rules are not static, and both regulators and legislators can revisit and update foundational, procedural resource planning requirements. This can make other content-based requirements more impactful. For example, states that require more extensive review of resource plans typically give regulators and stakeholders more opportunity to recommend content changes that better align utility resource plans with state policy objectives or that consider a wider range of resource options.

Updating resource planning rules can be ad hoc, prompted by legislation or an executive order, or planned for a regular cadence. For example, the Washington legislature prompted revisions to resource planning through the passage of the Clean Energy Transformation Act.[14] In Michigan, the statute that established resource planning requires the commission to open a proceeding to review the current regulations and revise the rules every five years.[15] The statute also requires the commission to consult with other government agencies and interested parties in this proceeding. The predetermined timeline for review creates an opportunity to continuously improve on the process and provides certainty around when planning requirements will shift.

3. How to Reimagine Resource Planning

Challenges of Planning for an Uncertain Future during a Period of Rapid Change

We observe that IRPs must maintain three core qualities to be effective tools for utilities and regulators to evaluate resource decisions, as outlined in Exhibit 12.

Exhibit 12 **Core IRP qualities and why they're important to utilities and regulators**

IRP quality	Definition	Why quality is important to regulators	Why quality is important to utilities
Trusted	The IRP is transparent and well vetted, with stakeholder input.	When resource plans are trusted, regulators can use them as evidence that future investments are prudent and in the public interest.	When utilities seek input from their customers and engender trust in their assumptions, they can develop an accurate plan that meets customer energy needs and leads to regulatory approval.
Comprehensive	The IRP can accurately represent the costs, capabilities, system impacts, and values of resources that might be available within the planning time horizon; the IRP can consider actions across the transmission and distribution systems as portfolio options.	When plans are comprehensive, regulators can ensure that options to best serve customers have been surfaced and tested.	When plans are comprehensive, utilities can adequately assess the value and risk of their potential future investments.
Aligned	It is clear how the plan evaluates options to meet traditional planning requirements such as reliability, affordability, and safety, as well as state and federal policies and customer priorities, such as reducing emissions and advancing environmental justice.	When plans are aligned, regulators can assess whether the recommended portfolio can perform across the range of performance outcomes within their mandate.	When utilities demonstrate that plans are aligned with policy objectives, they can avoid future disallowance of investments and under- or over-procurement of resources.

Source: RMI

A few major trends are challenging utilities and regulators to maintain these qualities in planning processes, including but not limited to:

- Rapid technology change and shifting resource costs[16]
- A range of new state and federal policies that expand objectives beyond affordability, reliability, and safety to include emissions reductions, advancing environmental justice, economic development, and supporting electrification of buildings, transportation, and industry[17]
- Increasing recognition that decisions made on the distribution and transmission systems have an impact on resource planning and vice versa[18]
- Increasing stakeholder awareness that resource planning decisions can affect local air quality, health, jobs, energy bills, and climate change[19]

Yet, if an IRP does not achieve these three qualities, its credibility, accuracy, and effectiveness may be eroded. The risks of unanticipated costs for ratepayers, disallowed future investments, dissatisfied customers, and failure to meet public policy objectives will increase.

Expanding Scope for Resource Planning

Making updates to the IRP process to ensure that it remains trusted, comprehensive, and aligned can make IRPs more complex. As such, making changes around the edges or simply adding new utility IRP requirements may no longer be what best serves a utility or regulator — especially with staff time and capacity constraints. To use a metaphor to guide our thinking, the opportunity is to avoid amassing incremental IRP expectations in a way that is like the straw that breaks the camel's back (see Exhibit 13, next page).

Exhibit 13 **How new expectations might challenge the IRP process**

To address these challenges more holistically, regulators have an opportunity to proactively and repeatedly refine the purpose, scope, roles, and tools — and to ask big questions about what the next generation of planning should look like — before making piecemeal enhancements.

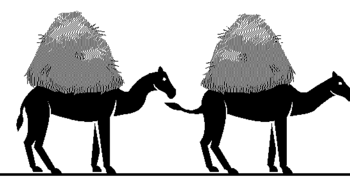
New IRP expectations

Purpose

Regulators and state policymakers have an opportunity to take a step back and clearly articulate goals for the electricity system over the next few decades and how the utility's options for future investment should be evaluated with respect to those goals. With clear goals and an updated framework for making decisions across multiple goals, the information that is needed to make decisions, which should be included in a plan, should become clearer.

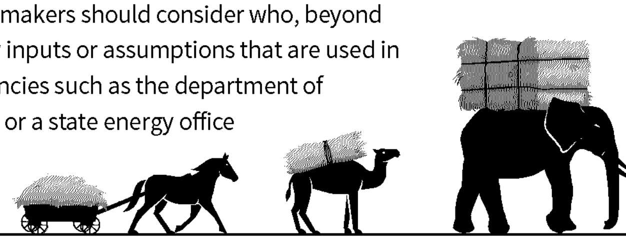
Scope

Once the information needed to make decisions is clear, regulators and state policymakers have an opportunity to reevaluate the specific scope of utility resource planning. Instead of adding more requirements to the IRP, there is an opportunity to define additional planning activities with their own objectives, and the links among them. Defining new, separate planning activities is a good option when specific decisions need to happen more or less frequently than an IRP or require more granular or more broad information. For example, regulators or policymakers may identify a need to create a separate distribution system planning process, an economy-wide decarbonization process, or an additional plan that tracks annual progress toward climate targets.



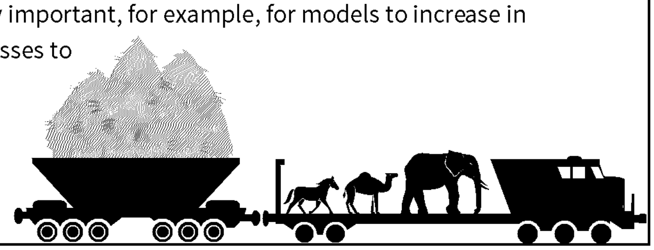
Roles

When clarifying the scope of IRP and other planning activities, state policymakers should consider who, beyond the utility or regulatory staff in the IRP process, might provide or verify key inputs or assumptions that are used in the IRP to maintain accuracy, credibility, and trust. For example, state agencies such as the department of transportation may be able to provide electric vehicle growth projections, or a state energy office might conduct a deep decarbonization study whose assumptions are used in an IRP.



Tools

Finally, the application of analytical tools and engagement processes that support resource planning need to be designed to be flexible, transparent, and continuously improved. It will be increasingly important, for example, for models to increase in computational ability and incorporate new technologies, and for processes to support utilities in meaningfully engaging stakeholders and in getting accurate market information (e.g., through consistent industry engagement and competitive solicitations). Effective tools and processes can reduce some of the friction in today's planning.



Source: RMI

The process of reassessing the purpose, scope, roles, and tools used to support planning before adding new IRP requirements should lead to a set of priority questions, for example as depicted in Exhibit 14:

Exhibit 14 **Examples of questions generated when reassessing purpose, scope, roles, and tools in planning**

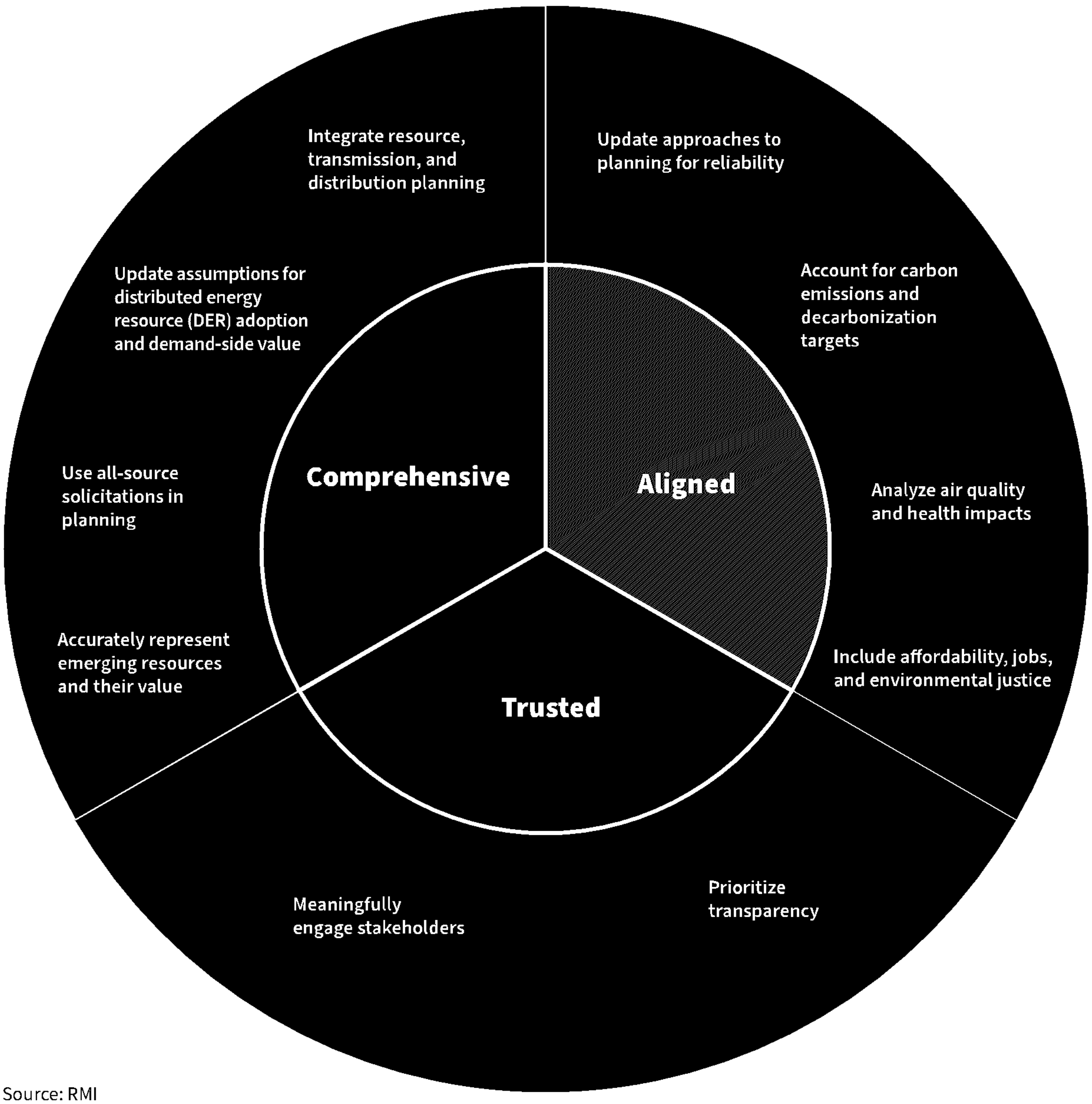
Category	Sample questions
Purpose	• What decisions will we make based on the outcomes of planning, and how might we design planning to support making those decisions? • How might we redesign planning to be able to evaluate decisions across multiple objectives?
Scope	• How should regional planning processes, statewide planning processes, and transmission planning processes interact with resource planning? • How can assumptions from other sectors' planning activities be integrated into the electricity system planning process (e.g., transportation plans, resilience plans, carbon plans)? • How should resource planning be integrated with distribution system planning? • How do planning and rate cases interact? • What are the links among planning, procurement, and siting? • How should benefit-cost analysis frameworks be used in planning?
Roles	• Can entities outside the utility or regulator provide or help evaluate assumptions, for example, the department of transportation providing EV forecasts, or environmental regulators assessing health impacts or the likelihood of meeting emissions reduction targets? • How might utilities collaborate with other utilities and states to assess regional needs and opportunities? • How should communities or customers' own energy planning processes be reflected in planning? • How might engaging with DER and emerging technology providers be structured to get critical inputs on how to characterize emerging technologies and their capabilities?
Tools	• Can modeling tools handle the spatial and temporal granularity required to assess value across resources? • Do modeling tools have accurate representations of the capabilities of emerging resources? • Do processes leverage stakeholder knowledge and input to improve assumptions and inputs? • Is data sufficiently transparent to enable thorough review by stakeholders and the commission?

Source: RMI

Overview of Planning Enhancements

When seeking to address these questions, utilities and regulators can look to approaches that have been tested in IRPs across the country that can "enhance" plans to be more trusted, comprehensive, and aligned. These enhancements are summarized in Exhibit 15:

Exhibit 15 **Summary of options to enhance resource planning**



Source: RMI

To build **trust** in resource plans, regulators and utilities are:

- **Prioritizing transparency,** by updating rules that assess what information may be held as confidential or proprietary — and applying those rules to ensure that stakeholders have the information they need to engage effectively in the IRP process

- **Meaningfully engaging stakeholders**, with an inclusive and substantive process for input before and during the plan's development

To make plans more **comprehensive**, regulators and utilities are:

- **Integrating resource, transmission, and distribution system planning,** to better understand how decisions at one level of the grid might affect others

- **Using all-source solicitations in the planning process,** to bring in timely market data as a basis for making procurement decisions

- **Updating assumptions and modeling tools for DER adoption and value,** to more accurately forecast DER growth patterns and impacts and assess DERs' costs and benefits

- **Accurately representing emerging resources and their value,** by including all options that may be commercially available in the planning horizon and using models with a level of spatial and temporal granularity needed to reveal values

To **align** resource plans with evolving objectives and understand the impacts of plans on people, regulators and utilities are:

- **Updating approaches to planning for reliability,** to better understand the risks, vulnerabilities, and types of solutions that can contribute to reliability, including resource adequacy and resilience

- **Accounting for carbon emissions and decarbonization targets,** to assess progress and alignment toward climate goals or better understand the risk of future climate policy

- **Analyzing health and air quality impacts** across resource options and portfolios

- **Including affordability, jobs, and environmental justice,** to make the human impacts of planning clearer

In the next three chapters, we walk through examples of enhancements that have already been tested in IRPs across the country: *Chapter 4 — Trusted*, *Chapter 5 — Comprehensive*, and *Chapter 6 — Aligned*.

4. Trusted

IRPs are most useful to utilities, regulators, and stakeholders when the processes and outputs are trusted. If regulators trust plans, they can use them as evidence in evaluating future resource decisions. When utilities use processes that build trust in plans, they can better meet their customers' needs, get more accurate information, and build support for regulatory approval of the plan and future investments. A trusted planning process may also increase stakeholders' satisfaction and improve the quality of engagement. However, planning today faces several challenges that impede trust, such as information gaps among utilities, stakeholders, and regulators, the perception of bias, the complexity of the system being modeled, and the number of unknowns when planning under uncertainty.

In this section, we highlight how regulators and utilities have increased trust in the planning process and outcomes through efforts that increase transparency and meaningfully engage stakeholders. With enhancements that address data transparency, expose modeling assumptions, and support stakeholder input, plans are more likely to have buy-in and can be used as support in future investment or cost recovery decisions.

Exhibit 16 **Summary of enhancements to make planning more trusted**

Enhancement	Leading practices and examples
Prioritizing transparency	• Establish rules or guidelines that maximize data transparency • Use a consistent set of assumptions or scenarios • Increase stakeholder access to modeling assumptions • Make plans accessible and relevant to a broad range of stakeholders • Develop and track metrics across IRPs
Meaningfully engaging stakeholders	• Define how to engage stakeholders before and during plan development • Create a dedicated IRP advisory group • Document how stakeholders influenced the plan • Reduce barriers to participation

Source: RMI

Prioritizing Transparency

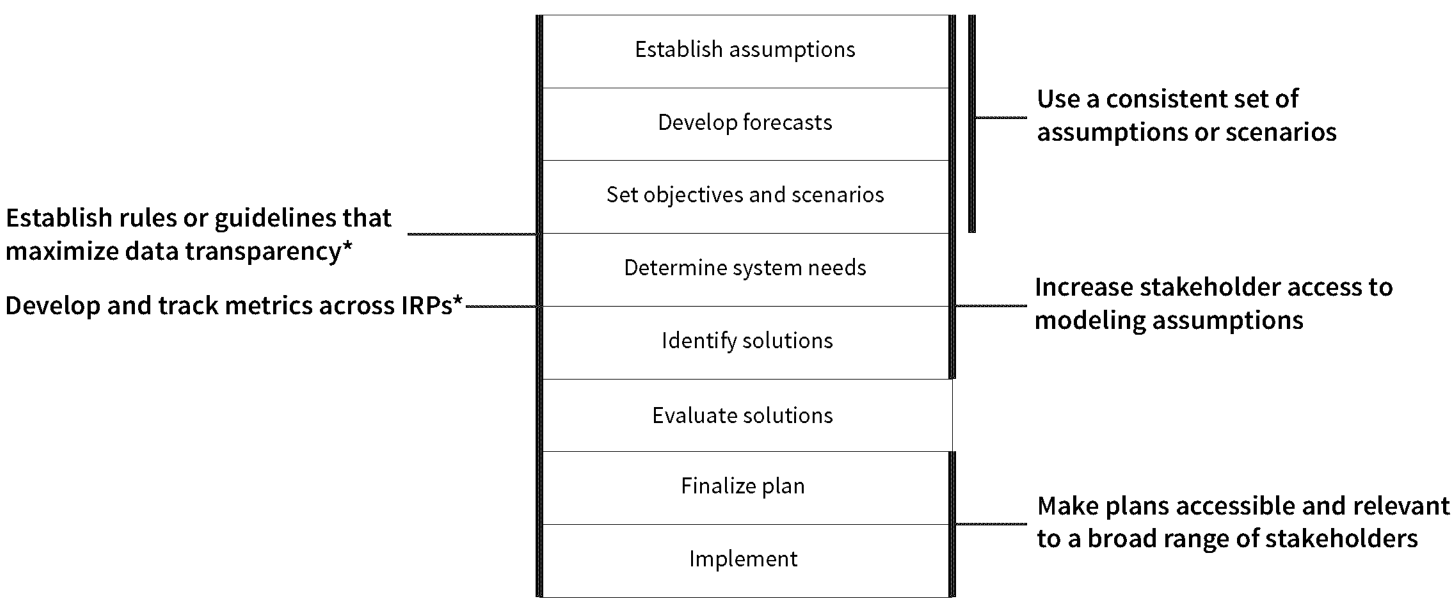
Visibility into data, key assumptions, analytical processes, and decision-making allows regulators and stakeholders to understand and interpret the resource plan results, which can increase trust in the outcomes. With an evolving generation mix and rapidly changing assumptions and modeling capabilities, transparency is even more important. Plans that withhold critical data require stakeholders and regulators to consider the outputs as valid or dismiss the outputs as untrustworthy without being able to understand and verify the underlying assumptions. This lack of transparency can also limit stakeholders' ability to meaningfully contribute solutions to resource planning challenges and can make it more difficult and time-consuming for regulators to compare findings.

Most utilities make their resource planning processes and outcomes public and transparent to some degree. Typically, stakeholders can access final plans on utility websites or through the state commission. However, only some states outline specific data transparency rules or guidelines for resource plans, which leaves the decision of what to share and how to share it up to the discretion of the utility.

Leading Practices and Examples

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 17.

Exhibit 17 **Where options for prioritizing transparency might be applied in the IRP process**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Establish rules or guidelines that maximize data transparency. In some states, regulators detail specific data that must be shared. New Mexico, for example, requires utilities to include the specific cost data used in portfolio development, including "capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs."[20] Thus, Xcel Energy Southwestern Public Service Company includes unit-specific cost data and capacity factors for all generation units in its IRP.[21] This allowed stakeholders to understand the utility's assumptions, like how thermal units operate within the model, without running the model themselves.

Other states require transparency without detailing specific requirements. For example, the Oregon PUC's IRP guidelines promote general data transparency, outlining, "While confidential information must be protected, the utility should make public in its plan any nonconfidential information that is relevant to its resource evaluation and action plan."[22]

Use a consistent set of assumptions or scenarios. Regulators can provide additional guidance on critical assumptions or scenarios that must be included in an IRP. In Michigan, the commission opens a proceeding, with stakeholder participation, to establish specific modeling scenarios and assumptions for planning that utilities must include in addition to the utility's own scenarios and assumptions.[23] The Michigan Department of Environment, Great Lakes, and Energy and other interested parties can provide input into assumptions including, but not limited to, projected costs of different fuels, planning reserve margins and local clearing requirements, and applicable state and federal regulations, laws, and rules.[24]

Increase stakeholder access to modeling assumptions. In addition to data transparency, utilities can provide visibility into their modeling process so that regulators and stakeholders better understand the decisions influencing resource portfolios. In response to their 2021 Integrated Grid Plan, the Hawaii PUC outlined specific directives for Hawaiian Electric to improve the access and quality of their modeling assumptions.[25] These included directing the utility to provide narrative explanations in plain language for all workbooks and other quantitative data sets, to share live and unlocked spreadsheets to allow users to understand the formulas, and to notify parties via email when there are updates to key documents.[26]

In some cases, stakeholders have developed their own alternative portfolios in response to a utility's plan. Alternative, stakeholder-driven portfolios can be an effective way to challenge assumptions and expose portfolio options the utility may not have originally considered that perform better on reliability, cost, or other policy objectives. If utility assumptions are not transparent and accessible to stakeholders, it may be more difficult for commissions to make an "apples to apples" comparison of utility and stakeholder-driven portfolios.

Utilities or regulators can reduce information asymmetry and support consistency by providing access to utility models so that stakeholders can accurately baseline their results against the utility's modeling. The Michigan Public Service Commission (MPSC), for example, requires that "modeling inputs and outputs in the model-dependent binary format should be made available to parties that obtain a license."[27]

Increasing stakeholder access to modeling means that more portfolio options may be generated and regulators must have the technical capacity and a clear approach to adjudicating different results. In a New Mexico proceeding to replace the retiring coal-fired San Juan Generating Station, utilities were ordered to provide access to modeling and stakeholders proposed alternative portfolios. As a result, stakeholders were able to provide evidence that their own portfolios met the same standards of reliability, with the same underlying assumptions. In the hearing examiner's recommendation, which the commission ultimately adopted, the hearing examiner described the factors for making decisions across cost, reliability, community benefits, environmental impacts, and meeting the policy objectives of the Energy Transition Act. The hearing examiner also identified where portfolios had consistent actions that should be implemented without regret (e.g., signing contracts for several solar projects) and where the differences in portfolios were (e.g., using battery storage or gas to meet reliability) that required further judgment.[28]

Open-access modeling

Open-access modeling is an emerging practice that has potential to enable stakeholders to provide meaningful input into modeling with fewer cost and access barriers than proprietary software. The term "open access" includes a wide array of modeling practices, ranging from models that are free and publicly accessible, to models that provide access to source code but may still require additional purchases or licensing to run.

The national labs, universities, and other organizations have developed and continue to improve open-access planning models. Some advocates are already using the open-source-and-access capacity expansion model GenX to model alternative pathways to utility plans.[29] Other examples include Switch 2.0, an open-source platform designed for resource plan modeling that has been used to model Hawaiian Electric's 100% renewable power system, and Breakthrough Energy's open-source production cost model.[30]

Although there are no known examples of utilities using open-access modeling in resource planning to date, this is likely to change soon. Notably, PGE Oregon plans to use GridPath, an open-source model, for its flexibility analysis in its next resource plan.[31]

Make plans accessible and relevant to a broad range of stakeholders. To achieve the benefits of increasing transparency, resource planning must also be understandable. Regulators and utilities can promote practices that ensure that objectives, process, data, and outputs are clear, organized, and useful. Several utilities have incorporated practices that improve the accessibility of their reports. These practices include:

- Summarizing key takeaways in accessible language at the beginning of each section and in executive summaries
- Incorporating simple and meaningful charts
- Embedding internal links to ease navigation
- Developing IRP websites or data clearinghouses to share additional information
- Hiring writers who can translate technical information for nontechnical audiences

Develop and track metrics across IRPs. Consistent metrics can be useful for tracking changes between IRPs or progress toward plans since the previous IRP. Every four years, utilities in Washington are required to develop clean energy implementation plans, in addition to their IRPs, that track the progress utilities are making toward state goals. Statute and administrative rules outline a detailed process to identify, develop, and track "customer benefit indicators" in partnership with highly affected communities and vulnerable populations. These include indicators that track "energy benefits, non-energy benefits, reductions of burdens, public health, environment, reduction in cost, reduction in risk, energy security, and resiliency."[32]

Outside of state requirements, utilities, regulators, or stakeholders can voluntarily report data to the Resource Planning Portal, maintained by Lawrence Berkeley National Laboratory, which seeks to make IRP information comparable across utilities and years with standard inputs.[33]

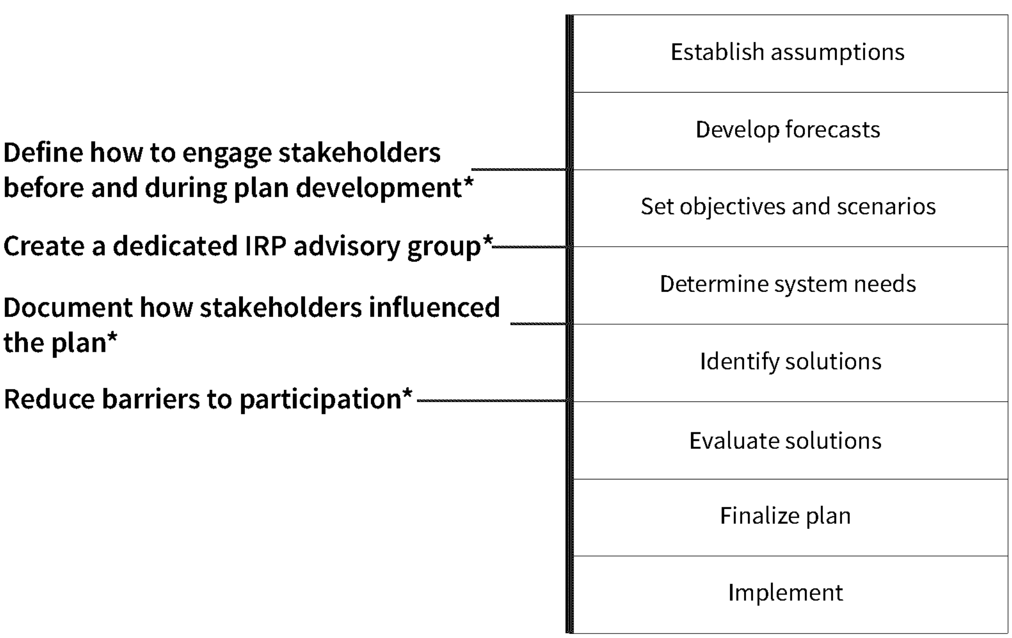
Meaningfully Engaging Stakeholders

Meaningful stakeholder engagement throughout the IRP process can improve planning outcomes. Stakeholders can provide a foundational understanding of what communities, businesses, and households need out of their future electricity system; data and information that result in more accurate cost and capability assumptions; and support for utilities and commissions in assessing whether the plan is aligned with the objectives in the jurisdiction.

Leading Practices and Examples

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 18.

Exhibit 18 **Where options for meaningfully engaging stakeholders might be applied in the IRP process**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Define how to engage stakeholders before and during plan development. Engaging stakeholders can require a significant time investment from the utility, commission, and interested parties. In some states, regulators provide specific guidance about what IRP engagement needs to entail. The New Mexico Public Regulation Commission (PRC), for example, requires utilities to run a public advisory process and meet requirements for minimum outreach, such as notifying intervenors that participated in recent related proceedings (e.g., a previous IRP proceeding or general rate case), providing notice in a newspaper in each county it serves, and including billing inserts.[34]

Create a dedicated IRP advisory group. Creating an advisory group that meets consistently can lead to better feedback and more robust discussions as participants become familiar with the content and processes over time. Advisory groups can be especially valuable when there will not be a proceeding with the opportunity for comment or testimony before the plan is finalized or when seeking input from stakeholders that have been historically underrepresented in the IRP process.

The Arkansas Commission requires utilities to organize and facilitate a Stakeholder Committee that consists of retail and wholesale customers, independent power suppliers, marketers, and others who are interested.[35] Austin Energy, a municipal utility, works closely with a consistent advisory working group to inform its Energy Resource, Generation, and Climate Protection plan. The group ensures that the plan meets the city's environmental, efficiency, and affordability goals and includes traditional voices, such as commercial and industrial customers, as well as people who represent low-income communities.[36]

Utilities and regulators are also establishing advisory groups with the explicit goal of advancing energy equity, including in resource planning. The utilities in Oregon are setting up Utility Community Benefits and Impacts Advisory Groups, prompted by the enacted HB 2021, a major state climate law. The advisory groups are required to include representation from environmental justice communities and low-income ratepayers, and the commission is tasked with figuring out how utilities can compensate members for their participation.[37] While the groups are still being formed and guidelines are being finalized, commission staff see a future role for the advisory group in helping define metrics to quantify community impacts, which will be used to compare portfolios in the IRP.[38]

Document how stakeholders influenced the plan. Many utilities publish the number of stakeholder meetings hosted and track how many stakeholders attended, but these quantitative metrics are limited in capturing the impact stakeholders had on the final plan. In Washington, utilities are required to take a more comprehensive, qualitative approach to capturing stakeholder influence. Resource planning rules state that the utility must demonstrate how stakeholder input was used in the development of the IRP, including an explanation of how input was incorporated or why it was not.[39] This documentation can be seen, for example, in Appendix A of Puget Sound Energy's most recent IRP.[40]

Reduce barriers to participation. Resource plans and processes are complex and require stakeholders to invest significant time and resources to contribute meaningfully. Some states have adopted formal or informal practices to support wider engagement. Although these examples are not specific, in all cases, to IRPs, utilities and regulators may be able to adopt similar practices to support more diverse engagement in planning. These include but are not limited to:

- Compensating intervenors for their time[41]

- Identifying and defining communities that have been historically underserved and inviting members of those communities to advisory groups[42]

- Creating a linguistically and culturally accessible engagement strategy, including translating the IRP summary[43]
- Allowing sufficient time for stakeholders to plan and prepare for meaningful engagement (e.g., sharing materials with sufficient time for review before meetings and allowing sufficient time for additional stakeholder input after meetings)
- Selecting a neutral facilitator to develop workshops that support diverse engagement[44]

Exhibit 19 **Additional resources that support trusted resource planning**

Resource, authoring organization, when published	Overview
Access to Data, Advanced Energy Economy, September 2017	This report presents a case for data access to drive innovation for DERs and other utility programs, and provides recommendations for utilities and regulators for improving data access.
Advancing Equity in Utility Regulation, Berkeley Lab, November 2021	This report offers the perspectives of four authors on how to incorporate energy equity into utility regulation. The authors cover topics that are relevant to resource planning, such as intervenor funding and program design.
Equity in Evergy Kansas IRP Report, Synapse, September 2021	This report reviews Evergy's IRP and offers recommendations to the utility and the commission for better integrating energy equity.
Participating in Power: How to Read and Respond to Integrated Resource Plans, Regulatory Assistance Project (RAP), Institute for Market Transformation (IMT), October 2021	This report outlines specific strategies for local governments and other advocates to engage in IRPs and advance equity and social justice priorities and clean energy.
Public Utility Commission Stakeholder Engagement: A Decision-Making Framework, NARUC, January 2021	This report provides a framework to guide commissions in designing an effective approach to stakeholder engagement. The framework covers scope, facilitation approach, engagement approach, meeting format, timeline, engagement outcomes, and follow-up. It also profiles 11 examples.
"**Resource Planning Portal,**" Berkeley Lab	This online resource organizes key data from utility resource plans in a standardized way, making data more comparable across utilities and plan years.

Resource, authoring organization, when published	Overview
Reforming Energy System Planning for Equity and Climate Transformation (RESPECT), Acadia Center, November 2021	This report outlines two solutions — comprehensive planning, and separating planners and owners — to address challenges in utility planning processes.
"**Stakeholder Engagement in Integrated Resource Planning**," Berkeley Lab, presented to the Michigan Professional Standards Commission, August 2017	This presentation provides an overview of eight states' rules and guidelines for stakeholder engagement in planning.

Source: RMI

5. Comprehensive

One of the core purposes of integrated resource planning is identifying a portfolio of resources and actions that can maintain desired utility performance under a range of possible futures. Striving to be comprehensive in the resources and actions considered within the plan can help utilities identify unforeseen risks and opportunities to save costs and prepare for major shifts.

In this section, we define comprehensive to mean that plans can accurately represent the costs, capabilities, system impacts, and values of the resources that might be available within the planning time horizon; and that plans can consider actions across transmission and distribution as portfolio options. We highlight several approaches (summarized in Exhibit 20) that utilities and regulators have used to make plans more comprehensive — from integrating planning across transmission and distribution, to implementing all-source procurement and adopting new approaches to better understand the capabilities of demand-side resources and emerging technologies.

Exhibit 20 **Summary of enhancements to make planning more comprehensive**

Enhancement	Leading practices and examples
Integrating resource, transmission, and distribution planning	• Implement a distribution-system planning process to complement resource planning • Establish clearer touchpoints between transmission planning and resource planning
Using all-source solicitations in planning	• Use all-source solicitation results to inform planning • Use the planning process to structure an all-source solicitation
Updating approaches for analyzing DER adoption, electrification, and demand-side value	• Model DER adoption and electrification forecasts more granularly • Model interactions among DERs, and integrate those into planning scenarios • Treat DERs, including energy efficiency, as a resource in planning • Value the reliability contribution of DERs in planning
Using models that can accurately represent emerging resources and their value	• Select models and use features that enable more spatial and temporal granularity • Include resource options that are expected to be available in the market within the planning horizon

Source: RMI

Integrating Resource, Transmission, and Distribution Planning

Many utilities and regulators have updated resource planning practices to better understand needs and options for investment across the transmission and distribution system and the impact those investments might have on resource portfolios.

Within the distribution system, utilities have historically scaled down load projections to the circuit level to understand the need for grid investment. As the adoption of DERs and electrified end uses increases, utilities and commissions are seeing a need to transition toward a planning framework that can characterize their impacts with additional complexity. Regulators and stakeholders are increasingly asking utilities to use well-vetted assumptions about DER adoption and analyze the opportunity to avoid supply-side resources with demand-side solutions.

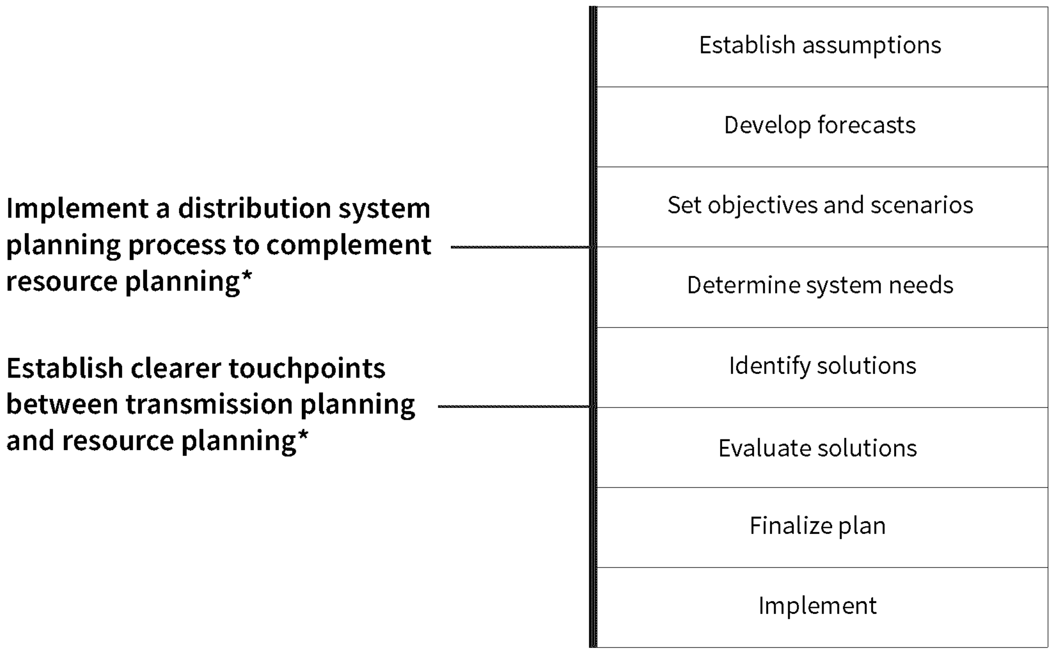
Transmission planning has largely taken place in regional planning processes at the regional transmission organization level. Yet transmission can be a key constraint or enabler in bringing new supply-side resources online. State commissions and FERC recognize that state and federal coordination on transmission planning is required to improve how projects are planned and paid for and kicked off a joint task force in 2021 to ensure cooperation.[45]

Leading Practices and Examples

Commissions are taking action on integrated planning, from opening proceedings that holistically reexamine the range of planning activities, to defining new distribution planning processes.[46] From 2019 to 2021, NARUC and NASEO facilitated a task force to develop visions and resources for comprehensive electricity planning with commissioners and state energy offices across the country. The task force resulted in five roadmaps with different options for integrating resource, distribution, and transmission planning in different utility and regulatory contexts.[47]

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 21 (next page).

Exhibit 21 **Integrating resource, transmission, and distribution planning might occur before or throughout the IRP process**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Implement a distribution system planning process to complement resource planning. In at least 21 states, utilities are required to develop distribution system plans.[48] Distribution system planning has become a venue for understanding grid modernization needs by conducting analyses such as quantifying hosting capacity (how much DER can be added to a distribution circuit without upgrades while maintaining reliability), forecasting DER adoption, updating interconnection studies and process, and understanding the opportunity for non-wires alternatives. In some of these states, such as Oregon, distribution system planning has also become a venue for exploring local benefits and impacts, opportunities for new programs, community needs and customer preferences, and planning for resilience.[49]

In states that also have an IRP process, regulators and utilities are striving to make sure that inputs and scenarios are consistent. In Minnesota, current integrated distribution planning (IDP) requirements ask utilities to describe how IDP and IRP are coordinated.[50] In its most recent IDP, Xcel Minnesota reported that its EV and DER forecasts are now coordinated across the planning processes and that its consideration of non-wires alternatives is coordinated across the IRP and IDP.[51]

Rather than implement a separate planning process, some jurisdictions are creating an integrated planning process. Hawaii, for example, has developed an integrated grid planning process that characterizes grid needs at the distribution, transmission, and generation levels; analyzes those needs in conjunction with behind-the-meter forecast customer needs and resources; and recommends customer-sited programs and utility-scale projects for procurement.[52]

Establish clearer touchpoints between transmission planning and resource planning. There are also examples of how utilities consider the costs of new and necessary transmission in resource planning. In Colorado, utilities are required to evaluate current transmission capabilities and future needs as part of resource planning. The utility is tasked with estimating the cost of new transmission for any proposed resource acquisitions in the resource plan and considering the transmission costs and benefits provided by resources as part of the bid evaluation criteria.[53]

Similarly in Oregon, utilities are required to include fuel transportation and transmission costs for each resource considered in planning and to model existing and future transmission associated with proposed portfolios.[54] The Oregon PUC also requires utilities to consider transmission as a resource option on a "consistent and comparable basis" with other resources.[55] In outlining how transmission should be considered, the commission highlights traditional and nontraditional benefits, explicitly including the opportunity to make purchases and sales, the potential to reach less costly resources in remote locations, and improvements to reliability.[56] In its 2019 and 2021 IRPs, PacifiCorp used models that could endogenously consider costs and transmission capabilities associated with new resource additions within its six-state territory.[57] There is an opportunity to further explore ways to more fully integrate resource planning with regional and interregional transmission planning processes.

Using All-Source Solicitations in the Planning Process

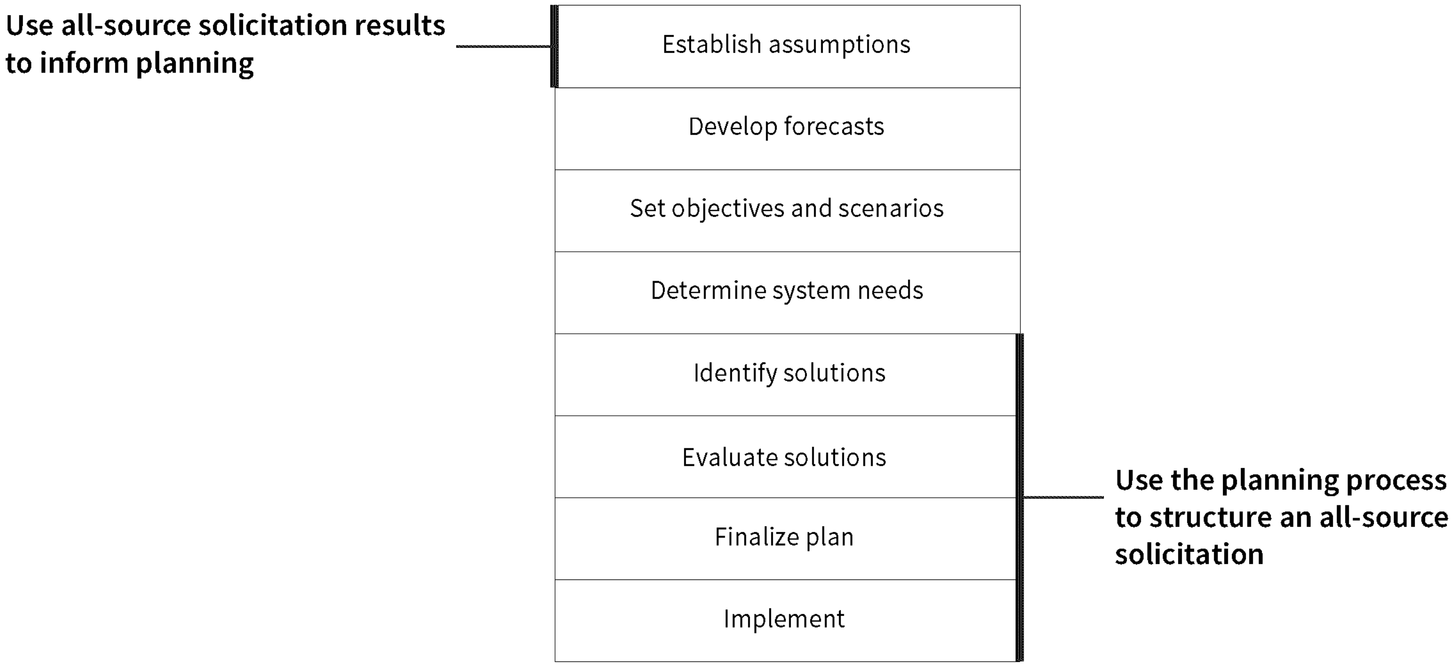
Traditionally, IRPs analyze the performance of portfolios with assumed resource costs and capabilities, and develop an action plan for procuring a set of near-term resources, if needed. In most states, procurement is an entirely separate process from planning, with utilities seeking approval to procure specific resources (e.g., solar or a gas plant) outside of the IRP (see Exhibit 11: How acknowledgment or approval of an IRP relates to procurement in 12 states, page 27). Utilities are often asked to justify the need for a new resource when seeking approval for procurement of a resource, referencing analysis in the IRP.

In contrast to the traditional approach of procuring a specific resource, all-source solicitations are requests for proposals that define the utility's need (e.g., in terms of energy, capacity, or flexibility services) and allow all resources to submit bids to meet the need. Effective all-source solicitations evaluate combinations of bids as portfolios to understand which combination of bids can meet the described need and perform best across solicitation evaluation criteria. The process of evaluating bid options as a portfolio is very similar in concept to portfolio analysis in an IRP, which has led utilities and regulators to seek out processes that can effectively combine them.

Leading Practices and Examples

Leading jurisdictions have updated rules or guidelines that redefine the relationship between planning and procurement and have required all-source solicitations as part of a planning process, as summarized in Exhibit 22 (next page). All-source solicitations are being used to support planning processes in two key ways: as the intended and integrated outcome of a planning process, or as a source of up-to-date and local inputs and assumptions.

Exhibit 22 **Options for building all-source procurement into the IRP process**



Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Use all-source solicitation results to inform planning. Michigan's statute requires utilities to issue a request for proposals for supply-side resources before beginning a planning process. The results of the request for proposals are intended to inform resource costs and capabilities used in planning, and the utilities are not required to adopt any proposals. If the plan identifies a need for new resources and is approved by the commission, the utility is required to finalize costs through an additional competitive bidding process before final approval.[58] Utilities in Indiana, including the Northern Indiana Public Service Company (NIPSCO), have also been using this approach of releasing all-source solicitations to inform their planning process over their past few planning cycles.[59]

Use the planning process to structure an all-source solicitation. In Colorado, resource planning rules require that an all-source, competitive solicitation be filed as a component of a utility's resource plan.[60] In Phase I of the Electric Resource Planning process, utilities establish assumptions, load forecasts, and test scenarios to identify system needs with a range of uncertainty and then develop the structure and evaluation criteria for an all-source solicitation that can seek resources to fill those needs. After the commission approves the Phase I resource plan, including the solicitation and its evaluation criteria, the utility will issue the all-source solicitation and receive bids. Bids are analyzed together during Phase II, as a portfolio, to determine the final cost-effective resource plan and approved portfolio for procurement.

Updating Assumptions for DER Adoption and Demand-Side Value

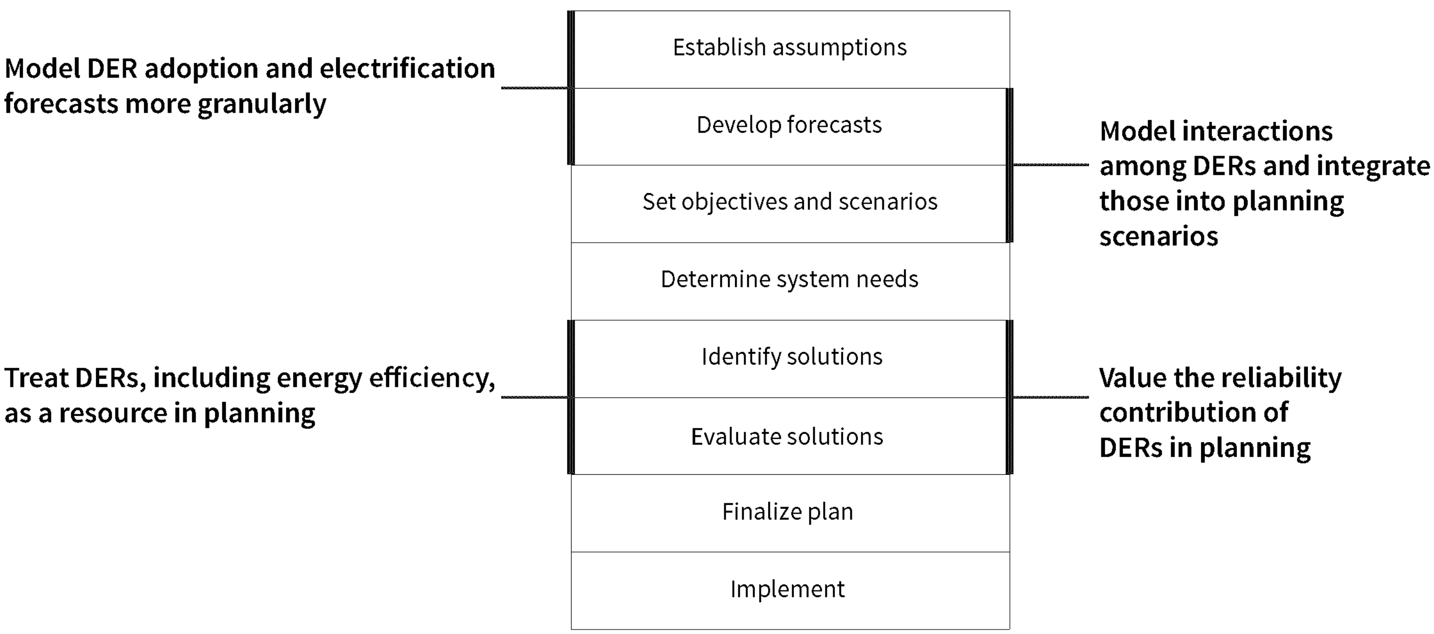
Distributed energy resources — including distributed generation, behind-the-meter storage, electric vehicles, and electrified building end uses such as heat pumps and heat pump water heaters — have long been a small component of utility load forecasts. Energy efficiency, which has been included in IRPs, has historically been applied as a reduction in load.

Today, utilities are seeing a need to proactively plan for distributed generation and electrification, and to update treatment of energy efficiency. Traditional methods may be insufficient in capturing locational value, impacts, and interactive effects among DERs.[61] Similarly, utilities and regulators are applying new methods that allow DERs, including energy efficiency, to be selected as a supply-side resource.

Leading Practices and Examples

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 23.

Exhibit 23 **Options for improving DER adoption and value in the IRP process**



Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Model DER adoption and electrification forecasts more granularly. Utilities are developing new models or engaging with consultants to model adoption rates and patterns for DERs such as electric vehicles and distributed solar and storage. For states with economy-wide decarbonization targets or specific sectoral targets that may affect electrification rates such as an EV sales target, IRPs should reflect meeting those targets. In addition to modeling adoption, some of these tools are helping utilities understand potential system impacts and opportunities — ranging from avoiding building supply-side resources to deploying non-wires solutions to avoid grid upgrades.

DER forecasting and impact assessment tools are emerging in utility planning processes. Sacramento Municipal Utility District in California, for example, has worked with Clean Power Research to deploy WattPlan Grid in its IRP process.[62] Utilities in California and Minnesota have used a model called

LoadSEER from Integral Analytics.[63] PGE Oregon has developed its own in-house model called AdopDER.[64] NREL also has its own adoption model called dGen, which it used to model adoption in its decarbonization planning study for Los Angeles.[65]

Model interactions among DERs and integrate those into planning scenarios. Utilities are combining DER adoption and electrification forecasts to understand their interactive effects on net load. Utilities are combining adoption trajectories for individual DERs into scenarios that represent different levels and shapes of load growth. Hawaiian Electric, for example, has used low, base, and high scenarios for DER adoption, where the high scenario actually expands the market beyond what is addressable by current programs (such as for multifamily properties that are challenging to reach with DER programming). It then combines these various technology adoption scenarios into several load forecasts and sensitivities — including to create “bookend” scenarios that represent maximum or minimum load growth. The high bookend, for example, includes high EV adoption with unmanaged charging.[66]

Treat DERs, including energy efficiency, as a resource in planning. Utilities and regulators are reassessing how they account for costs of DERs, so that they can be selected as a resource in planning. One approach is to create a “supply curve” of DERs that can be selected by capacity expansion models, typically used to optimize portfolios in planning. The Indiana utilities, for example, are required by the commission to model demand-side resources in a way that is consistent and comparable to supply-side resources.[67] In IPL’s 2019 IRP, for example, the utility (now known as AES Indiana) created demand-side management cost bundles that were selectable by their planning model.[68]

In addition to updating resource costs, utilities and regulators are reassessing the benefits and potential of demand-side resources and DERs. This includes updating cost-benefit tests, which are often used to determine the potential of demand-side resources or DERs that can be selected in an IRP.[69]

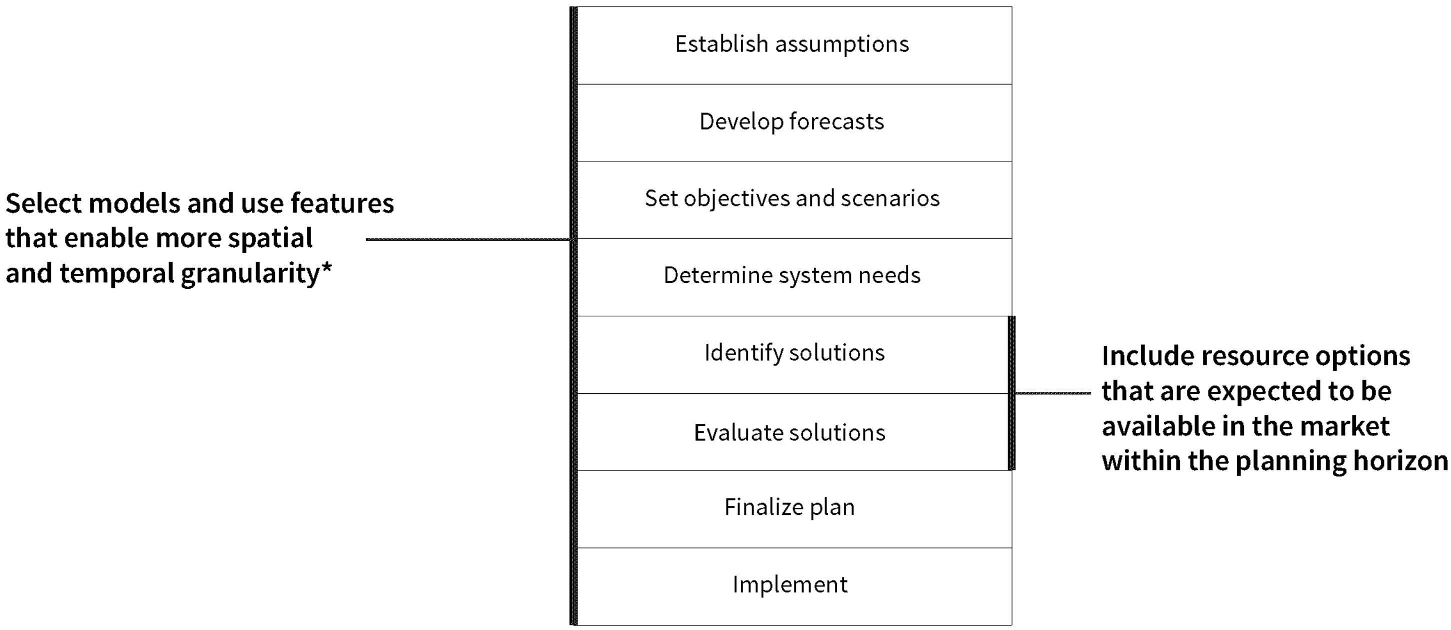
Value the reliability contribution of DERs in planning. DERs, including energy efficiency, can provide reliability services. California requires regulated utilities to include demand response in long-term procurement plans and in meeting resource adequacy requirements.[70] The California Public Utilities Commission (CPUC), in coordination with the California Independent System Operator (CAISO), establishes how demand response’s resource adequacy contribution should be valued so that it can receive capacity credit or count toward utility resource adequacy requirements.[71]

Accurately Representing Emerging Resources and Their Value

A suite of emerging, low-carbon resource options such as hydrogen, carbon capture and storage, and long-duration energy storage, accelerated by incentives in the Inflation Reduction Act, will become commercially viable and economically competitive within utilities’ planning horizons.[72] Utilities and regulators are updating modeling approaches and processes to consider, accurately value, and assess the opportunities and trade-offs of these emerging options.

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 24 (next page).

Exhibit 24 **Options for representing emerging resources and their value**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Select models and use features that enable more spatial and temporal granularity. Many resource planning models today are capable of more temporally granular analysis than previously because of continuous improvement and advanced computing. Resources such as battery energy storage and demand flexibility can provide services sub-hourly in specific locations, and those values are often not captured by planning models.[73] Similarly, models that are able to optimize over the full year, rather than on sample days or other smaller periods, can make the value clearer for resources such as long-duration storage that provides several-day or even seasonal services.[74]

Sufficient spatial granularity can properly capture the benefits of diverse variable renewable resources spread out over a region. Furthermore, models should consider interactions between neighboring balancing areas or market regions, such as the availability of interregional power transfers.

Include resource options that are expected to be available in the market within the planning horizon. The long planning horizon for resource planning means that some resources that will be viable within the planning period are not commercially ready today. As such, utilities and regulators are are challenged with determining fair and informative ways to incorporate these potential technologies. Entergy shared draft IRP assumptions with stakeholders in advance of its anticipated 2023 filing. The assumptions included a comprehensive assessment of the technology maturity levels of all options the company might consider in its IRP. Entergy retained several options that were designated at the demonstration phase maturity for portfolio modeling, including hydrogen for co-firing in gas turbines, though it is not clear why it did not retain other emerging options, such as flow batteries or tidal energy, that were designated at the same level of maturity.[75] Conducting an all-source solicitation can also help discover the full range of resource options that may be available within the period of a need identified in an IRP.

Exhibit 25 **Additional resources that support comprehensive resource planning**

Resource, authoring organization, when published	Overview
All-Source Competitive Solicitations: State and Electric Utility Practices, Berkeley Lab, March 2021	This report provides a comprehensive overview of all-source competitive solicitations and details various design and implementation options and associated issues.
Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, Berkeley Lab, April 2020	This report evaluates common and enhanced methods for valuing the economic benefits that flexible loads in buildings can provide the electric utility system to be used in resource planning.
Electric Distribution System Planning with DERs — High-Level Assessment of Tools and Methods, Pacific Northwest National Laboratory (PNNL), March 2020	This report outlines tools and methods that enable distribution planning with DERs and evaluates their capabilities and where advancements are needed.
How to Build Clean Energy Portfolios, RMI, RAP, September 2017	This online resource and accompanying report highlight best practices in procurement. They include stakeholder-specific recommendations, case studies of procurement processes, and a state-by-state review of procurement today.
"**Integrated Distribution System Planning**" web page, Berkeley Lab	This online resource has resources and presentations from past state, regional, and national trainings on integrated distribution system planning, and links to related publications.
"**The Integrated Energy Network**," Electric Power Research Institute	This online resource introduces the concept of an integrated energy network and aggregates a growing body of research to enable this pathway.
Making the Most of the Power Plant Market, Energy Innovation, April 2020	This report, geared toward regulators, recommends best practices for all-source electric generation procurement and reviews several case studies in depth.
Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets, Berkeley Lab, January 2021	This report covers how utilities and markets can move beyond reducing load forecasts to represent efficiency, and toward analytical methods that consider energy efficiency as a resource that can compete with supply-side options.

Resource, authoring organization, when published	Overview
Methods, Tools and Resources: A Handbook for Quantifying DER Impacts for Benefit-Cost Analysis, National Energy Screening Project, March 2022	This handbook provides guidance on quantifying the benefits and costs of DER investments.
"**NARUC-NASEO Task Force on Comprehensive Electricity Planning,**" 2018–20	This online resource is the product of a two-year collaborative initiative in which commissioners and state energy office participants explored options to better align distribution system planning and resource planning processes. It has additional context on the task force and a comprehensive resource library for planning. It includes resources such as a blueprint for state action and task force cohort roadmaps.
Opportunities to Improve Analytical Capabilities towards Comprehensive Electricity System Planning, NARUC-NASEO, February 2021	This working paper shares analytical gaps to comprehensive planning identified by the NARUC and NASEO task force.

Source: RMI

6. Aligned

Utilities and regulators across the country have demonstrated that planning can meet traditional objectives, such as maintaining system reliability under new risks, and analyze a variety of new objectives driven by state policy or customer needs, including emissions reductions and community impacts.

Exhibit 26 **Summary of enhancements to make planning more aligned**

Enhancement	Leading practices and examples
Updating approaches to planning for reliability	• Redefine the goals and metrics for assessing reliability in an IRP • Integrate resilience into planning • Improve alignment between portfolio optimization models and reliability analysis • Analyze the impacts of reliability-threatening scenarios, including those exacerbated by climate change • Understand regional reliability needs
Accounting for carbon emissions and decarbonization targets	• Develop capped emissions scenarios that constrain resource portfolio choices based on targets • Estimate the emissions of each portfolio over time to assess the likelihood of compliance with targets • Use economy-wide deep decarbonization studies to inform planning scenarios • Establish a default preference for renewable energy resources
Analyzing air quality and health impacts	• Publish pollutant values for existing assets and new resource options • Develop environmental and health cost scenarios, and analyze portfolio impacts • Work with environmental regulators to assess likelihood of compliance and impacts
Including affordability, jobs, and environmental justice	• Plan for community transition associated with asset retirements • Estimate comparative rate impacts of portfolios • Define and map disadvantaged communities to assess impacts • Factor community acceptance into resource availability and feasibility of plans

Source: RMI

Updating Approaches to Planning for Reliability

Demonstrating that a portfolio of future resources can operate reliably under expected future conditions has long been a core priority for resource planners.

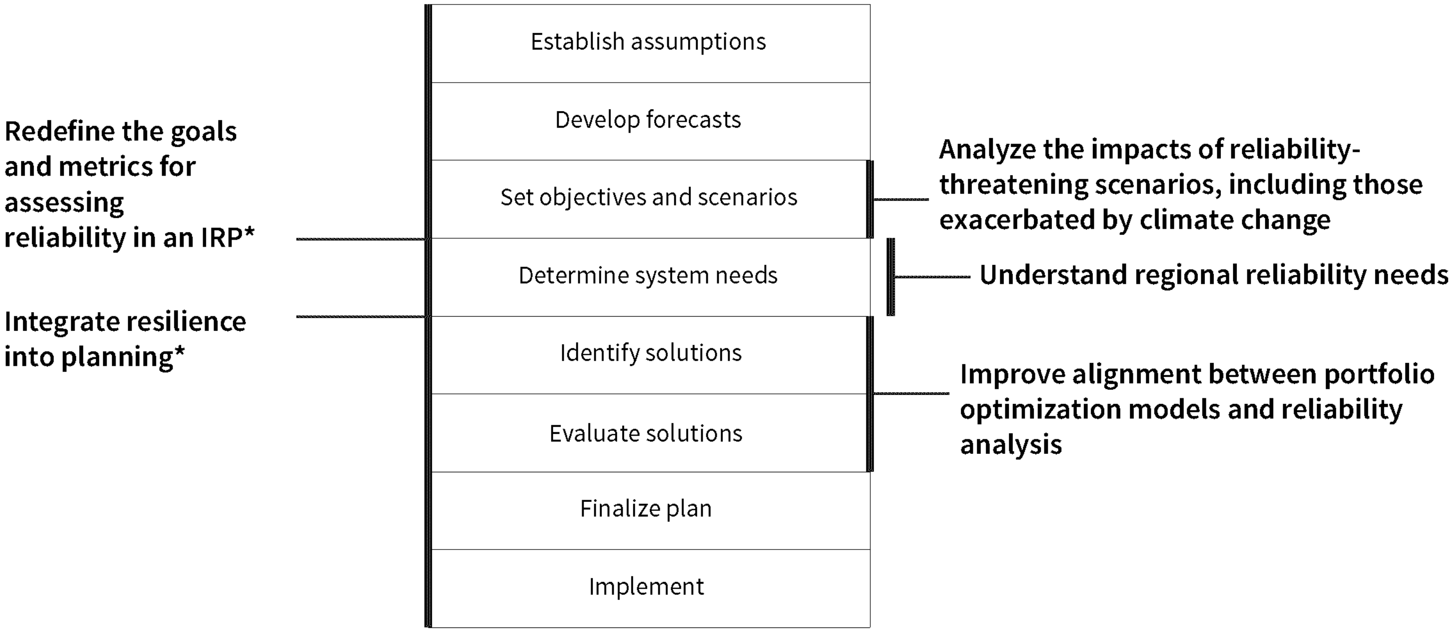
Although there are many components of reliability, resource adequacy has been the central focus within IRPs. Resource adequacy — having sufficient resources to meet projected load over a specified time and granularity and given a range of uncertainty for supply and load — typically determines whether a utility identifies a need to build new resources in an IRP. Many utilities today assess resource adequacy in IRPs by calculating whether the total capacity of their portfolio can meet peak demand plus an established reserve margin that accounts for uncertainties. Most commonly, the total peak capacity and reserve margin for planning are designed to meet a standard of 1-day-in-10-years loss of load, and future portfolios must demonstrate they can meet this standard.

Yet there is mounting evidence that when, why, and how reliability events occur are changing.[76] These changes in reliability threats — and the options for solutions that can mitigate them — are requiring resource planners to rethink traditional approaches to assessing reliability in planning processes.[77] In addition to updating approaches to resource adequacy, utilities and regulators are defining new ways of analyzing resilience in IRPs — another element of grid reliability.

Leading Practices and Examples

Utilities and regulators have updated reliability objectives and modeling approaches in resource plans to ensure that risks are more accurately characterized, quantified, and mitigated, and to assess how resource portfolios perform under a range of possible future conditions. In addition to more accurately characterizing risks, changes to how resource adequacy and resilience are assessed within an IRP can create the opportunity for a broader set of low-carbon technologies — such as long-duration storage and demand flexibility — to compete. These approaches, and where they might be applied in the planning process, are summarized in Exhibit 27 (next page).

Exhibit 27 **Options for updating reliability modeling throughout the IRP process**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Redefine the goals and metrics for assessing reliability in an IRP. Utilities and commissions have used a number of metrics quantify reliability-driven needs and characterize the reliability performance of portfolios across different scenarios. Oregon planning guidelines, for example, require utilities to assess expected and worst-case unserved energy in addition to loss of load probability and planning reserve margin.[78] These metrics are reported for each of the top-performing resource portfolios in PGE Oregon's 2019 IRP, for example.[79] Per a commission order on its prior IRP, PGE Oregon also conducted a "flexibility adequacy" study to understand the need for additional resources to meet ramping periods or to compensate for short-term forecasting errors.[80]

Integrate resilience into planning. Resilience, the ability to "anticipate, absorb, adapt to and/or rapidly recover from a potentially disruptive event," is a component of reliability that grid planners are increasingly integrating into IRPs.[81] In IRPs, utilities have identified threats and characteristics that support or hinder resilience in their jurisdictions and created methods to assess the resilience benefits of different resource options. In Green Mountain Power's (GMP) 2021 IRP, system resiliency was included as a core functional area within the implementation and action plan. GMP provided updates on four high-priority communities it is working with to improve resilience and set a goal for developing six "resiliency zones." Communities were identified based on reliability data and vulnerability, which included uncertain access to broadband and cellular service. GMP will work with the communities in the resiliency zones to deploy DERs and storage to improve reliability.[82]

Improve alignment between portfolio optimization models and reliability analysis. Capacity expansion models, which utilities use in resource planning to develop portfolio options, may not have the ability to test the reliability of portfolios across a large range of probabilistic weather and operational conditions.[vi] Thus, some utilities use production cost models or reliability-specific models to refine capacity needs and understand the reliability contribution of each resource type in planning. To harmonize these assumptions across its resource adequacy assessments and IRPs, CPUC provides a unified list of modeling inputs — load, generation, import, and transmission profiles. The inputs were developed using SERVM, a production cost model that includes probabilistic reliability assessment.[83]

Analyze the impacts of reliability-threatening scenarios, including those exacerbated by climate change. To comply with a 2020 update to the Washington Utilities and Transportation Commission's planning rules, PacifiCorp introduced a climate change scenario in its 2021 IRP and assessed the many impacts that climate change could have on planning assumptions.[84] To develop climate change data and scenarios, the company collaborated with the regional planning body, the Northwest Power and Conservation Council, and identified the impact of temperature to load and availability of hydro resources. The climate change scenario increased near-term summer peak by less than 1%, rising to nearly 3% by 2040. There was also a large impact on energy generation (decline of 7%) from declining hydro, pointing to potential future cost and risk.[85]

Con Edison in New York has developed approaches to assessing the impacts of climate change on system planning in response to requirements from the commission and legislature.[86] The utility downscaled global climate modeling results for its territory to look at impacts from flooding, heat, and extreme events. In addition to load impacts, the company found that the frequency and severity of reliability-threatening events would increase and sought to identify strategies that could improve resilience and adaptation in its service territory.[87]

Understand regional reliability needs. Understanding the regional reliability context can be key to identifying additional risks or mitigation opportunities in an IRP. Regional reliability studies can be useful for utilities to assess the total scope of investment across the region to avoid overbuilding or overbuying new resources. In the Southwest, for example, E3 recently conducted a study that was funded by several utilities demonstrating that utility IRPs in aggregate would be able to maintain resource adequacy in the region and that no further investment beyond what current IRPs specified was required.[88] The study also modeled increased loads due to climate change.

For vertically integrated utilities in regions with centrally organized wholesale electricity markets, regional approaches to assessing reliability adequacy are being incorporated into utility IRPs. For example, Midcontinent Independent System Operator's (MISO) resource adequacy planning process determines utility and local requirements, which utilities are required to demonstrate they can meet through their plans. This is done by assigning each resource that might be considered in utility portfolios an annual effective load carrying capacity, which is a probabilistic measure of its ability to perform on peak. MISO is also evolving its own reliability planning approach in ways that will affect utility resource plans — such as considering how to provide resource adequacy targets on a seasonal basis.[89]

vi Probabilistic, in this context, means incorporating an assessment of the likelihood of a weather or operational condition to occur. Probabilistic in the IRP context, more broadly, means attaching a probability or likelihood of occurrence to factors with uncertainty.

Accounting for Carbon Emissions and Decarbonization Targets

Utilities and regulators have developed a variety of approaches to accounting for carbon emissions in resource planning. For many utilities and regulators, this is driven by the need to meet mandatory state policy targets. Beyond mandatory carbon reduction targets, many utilities have set their own voluntary carbon reduction goals or are facing pressure to help meet the goals of the local jurisdictions and companies in their service territory.

Many utilities have historically accounted for emissions and climate policy risk in their resource plans by analyzing scenarios that include a cost of carbon or the federally defined social cost of carbon. The value and impact of carbon prices on how portfolios are selected have varied widely by jurisdiction. As examples:

- Duke Carolinas analyzed a base case portfolio in its 2020 IRP with and without a carbon price. The plan assumes a carbon price of $5 per ton starting in 2025 and increasing $5 each year afterward but does not detail how that cost was determined.[90]

- In New Mexico, a standardized cost of carbon must be included as an operating cost; low, medium, and high price sensitives were determined starting in 2010 and increase each year by 2.5% ($8, $20, and $40, respectively).[91] Utilities may also propose other carbon price sensitivities or approaches.

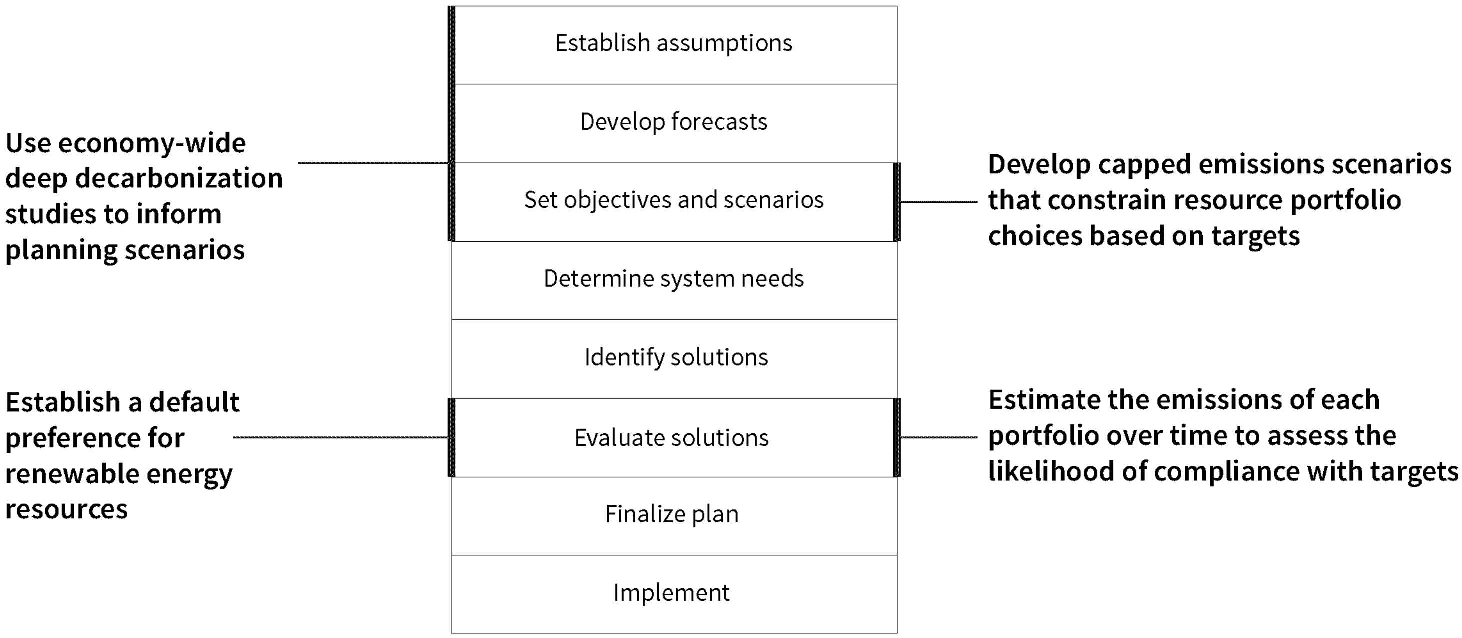
- PacifiCorp developed five "price-policy" scenarios with varying assumptions for carbon prices in its 2021 IRP. In these scenarios, carbon prices start at $10 per ton and approximately $21 per ton for medium and high cases, respectively. The utility developed an additional policy scenario to evaluate performance with a social cost of carbon, which started at about $45 per ton.[92]

- In Oregon, utilities are required to include at least one "trigger point" CO_2 price, defined as a price that would lead to choosing a substantially different resource portfolio.[93] IRPs in Oregon also have included a carbon price in their reference case scenarios, which can have a significant impact on the plans.

Leading Practices and Examples

To further account for emissions targets and climate policy risk of resource portfolios, utilities and regulators have evolved approaches within IRPs. Some states now require separate processes and documentation adjacent to IRPs, as is the case with CEIPs in Washington, which are filed in addition to IRPs and detail how the utility will meet interim targets, including deployment of renewables, energy efficiency, and demand response.[94] The following examples, and where they might be applied in the planning process, are summarized in Exhibit 28 (next page).

Exhibit 28 **Options for accounting for emissions and decarbonization targets throughout the IRP process**



Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Develop capped emissions scenarios that constrain resource portfolio choices based on targets. In California, a statewide planning process ensures that plans for the electricity sector's greenhouse gas (GHG) emissions are aligned with state policy. First, the California Air Resources Board develops a scoping plan that considers options for the state to meet economy-wide carbon targets and outputs a range of emissions targets for the electric sector. Then, the CPUC determines a system-wide GHG emissions target and models a reference system plan, which represents the full system and performs within the set targets. Utilities then file their own resource plans that align with the emissions caps. If the preferred portfolio does not align with the utility's portion of the emissions targets, written justification must be provided.[95]

Estimate the emissions of each portfolio over time to assess the likelihood of compliance with targets. Utilities with decarbonization targets are working with their environmental regulators to assess the likelihood of compliance given utility actions in IRPs and to establish emissions accounting methodologies. In Colorado, the commission has established a process to evaluate whether utility resource plans are aligned with the statewide GHG emissions reduction targets set by statute. The utilities are required to include projected emissions of owned and planned resources and assess the costs and benefits of a resource portfolio that is aligned with reducing CO_2 emissions by 80% of 2005 levels by 2030, a sectoral target suggested in the state's Greenhouse Gas Pollution Reduction Roadmap.[96]

Use economy-wide deep decarbonization studies to inform planning scenarios. Some utilities are incorporating deep decarbonization planning models, which analyze impacts of decarbonization across multiple sectors of the economy, into their plans to understand how their resource planning fits into the larger state decarbonization roadmap. As one example, PGE Oregon engaged with energy consultants to run a decarbonization study. The study explored how decarbonization of the local economy would affect electricity demand under three scenarios: high electrification, low electrification, and high DER penetration.[97] PGE Oregon then incorporated the modeled impacts of EV adoption, energy efficiency, and electrification into a load profile for a "decarbonization scenario" and tested IRP portfolios against this modified demand.[98]

Establish a default preference for renewable energy resources. In pursuit of effectuating state policy, some states require utilities to provide explicit justification when proposing new fossil fuel resources in their resource planning. In Minnesota, a 2022 statute prevents the commission from approving either new or refurbished nonrenewable generation in resource plans unless it's demonstrated that the renewables option is not in the public interest.[99] In determining "public interest," the commission must consider factors such as whether the resource plan is aligned with prior established GHG reduction goals, whether there are reliability impacts, and any utility and ratepayer impacts.[100] Similarly, in California, utilities must demonstrate why a lower-emitting or zero-emitting resource could not "reasonably" meet the identified need in order to propose a new or re-contracted natural gas plant.[101]

Analyzing Air Quality and Health Impacts

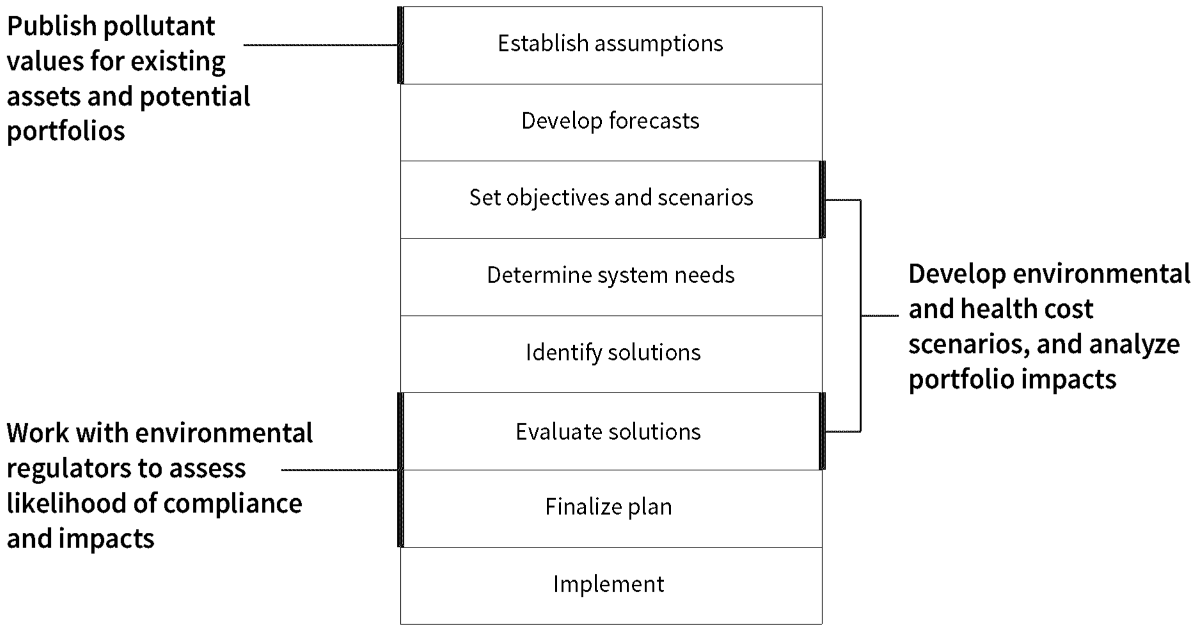
In addition to accounting for CO_2 emissions, leading states and utilities are developing more robust approaches to characterize the health trade-offs of different resource plan options. These approaches have most commonly been in response to state climate laws that prioritize environmental justice, reduce harm to historically disadvantaged communities, and move toward energy equity.

Most states that have resource planning requirements include language around assessing the environmental impact or compliance of existing resources and new resource options, such as demonstrating they can meet national or state air quality standards.

Leading Practices and Examples

Leading states and utilities are adding specificity to the requirements for assessing air quality impacts within resource plans, as summarized in Exhibit 29 (next page).

Exhibit 29 **Options for analyzing air pollution and health impacts within the IRP process**



Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Publish pollutant values for existing assets and potential portfolios. In New Mexico, resource planning rules require utilities to file with their IRP a description of existing resources, which includes emissions rates of criteria pollutants (NO_x, SO_x, CO, CO_2, and PM2.5) and mercury where possible.[102] Additionally, utilities are required to identify emissions assumptions for potential supply-side resource options.[103] Public Service Company of New Mexico's (PNM) 2021 IRP, for example, includes these values for each asset.[104] In addition to requiring that these values be provided, the New Mexico's IRP rules also state that "for resources whose costs and service quality is equivalent, the utility should prefer resources that minimize environmental impacts."[105]

Develop environmental and health cost scenarios, and analyze portfolio impacts. In Minnesota, the state statute applicable to resource planning requires the commission to, "to the extent practicable, quantify and establish a range of environmental costs associated with each method of electric generation."[106] Utilities are required to use these commission-defined values in evaluating and selecting options in their resource plans. In Xcel's Upper Midwest Energy Plan, for example, the utility includes values for "externalities," broken out by where impacts would occur (e.g., urban versus rural). In addition to including externality costs as sensitivities calculated across portfolios, the utility ran scenarios in which externalities were included in the model's optimization.[107] One of the five factors that the commission must balance in its approval of resource plans in Minnesota is minimizing "adverse effects on the environment," and optimizing portfolios that include quantified externalities encourages the commission to weigh this factor in its decision.[108]

Work with environmental regulators to assess likelihood of compliance and impacts. Utility commissions and environmental regulators are working together to redefine air and environmental impact requirements for resource plans. Michigan's resource planning statute, implemented in 2017, requires the commission to update the planning rules every five years through collaboration with the Michigan Department of Environment, Great Lakes, and Energy (EGLE). The statute also directs the commission to seek an advisory opinion from EGLE to evaluate how the utility's proposed plan will affect criteria pollutants and whether the plan can reasonably achieve environmental compliance.[109] The commission and EGLE are currently working together and with stakeholders to update the resource planning rules and consider what additional analysis should be included in EGLE's advisory opinion and the utility's plans.[110] Proposed updates under discussion include providing asset- and portfolio-level emissions data, conducting an analysis of vulnerable community impacts from fossil fuel generators, and assessing health impact estimates for PM2.5.[111]

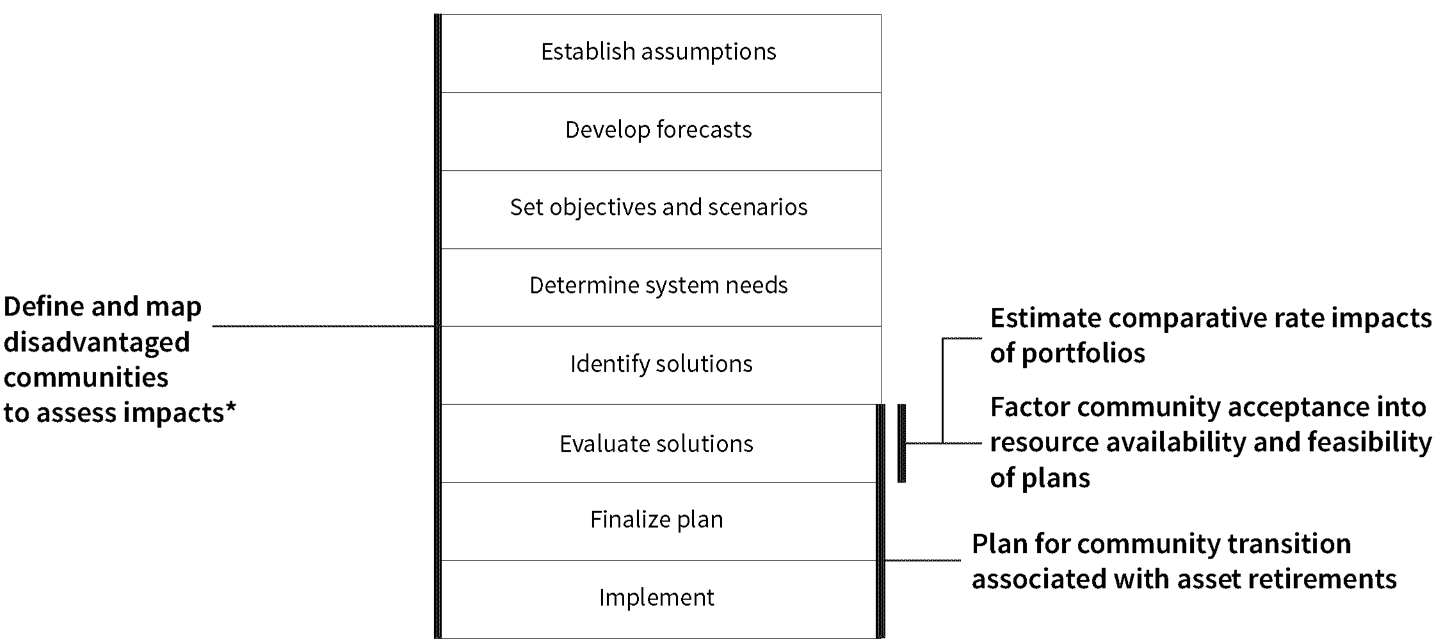
Including Affordability, Jobs, and Environmental Justice

Resource planning has, for the most part, focused on analyzing potential portfolios' ability to meet system needs. However, utilities and regulators are increasingly connecting the potential human impacts of utility plans to portfolio options within an IRP. Not only does this help utilities and regulators to understand and quantify potential human impacts, but it also outlines for people within a utility's service territory how different portfolios might affect them. Even if these impacts do not influence the development of the portfolios, understanding the impacts up-front can be a first step toward helping utilities, advocates, and regulators understand trade-offs and plan to mitigate some of the potential risks.

Leading Practices and Examples

The following examples, and where they might be applied in the planning process, are summarized in Exhibit 30.

Exhibit 30 **Options for including affordability, jobs, and environmental justice in resource planning**



*Applied before and throughout the process

Source: RMI additions to the "**Standard Building Blocks**" from the National Association of Regulatory Utility Commissioners-National Association of State Energy Officials (NARUC-NASEO) Task Force on Comprehensive Electricity Planning, 2019

Plan for community transition associated with asset retirements. IRPs model specific plant retirements and establish plans to address resulting system impacts. In Minnesota, utilities must also consider the human impacts of these plant closures in their IRPs. Specifically, a statute requires any utility that has scheduled an in-state retirement to collaborate with workers and worker representatives to create a plan to minimize the resulting employee dislocations.[112]

Estimate comparative rate impacts of portfolios. Changes to customer rates are determined in rate cases, separately from resource planning. However, estimating potential impacts of different scenarios or portfolios in an IRP can help regulators, customers, and consumer advocates interpret how planning decisions might affect energy affordability. PacifiCorp estimates several costs and risks across its portfolios, including rate impacts. In the 2021 IRP, PacifiCorp calculated nominal annual revenue requirements for each of its top portfolios and compared these with a benchmark portfolio.[113] This process does not calculate a specific bill impact but highlights the relative differences among potential plans.

Define and map disadvantaged communities to assess impacts.[vii] Before being able to evaluate whether and how utility services are serving disadvantaged communities, utilities must understand who and where these customers are. Several states require utilities to map disadvantaged communities in their planning processes, as a precursor to evaluating specific impacts of the plan on those communities. As one example, CPUC requires utilities to identify which disadvantaged communities they serve.[114] This information is then used to identify specific environmental justice issues that these communities face and to support compliance with the statutory requirements to minimize air pollution in disadvantaged communities.[115]

Factor community acceptance into resource availability and feasibility of plans. In its integrated grid planning process, Hawaiian Electric uses "renewable energy zones" to assess the potential for development and estimate transmission costs associated with resources that could be selected. Many stakeholders commented that the zones should be constrained in line with community acceptance. As a result, the commission has required Hawaiian Electric to propose a community engagement plan and to describe the impact of the community engagement on the constraints.[116]

vii Language differs by state. Disadvantaged communities are, as defined by the CPUC, "the areas throughout California which most suffer from a combination of economic, health, and environmental burdens. These burdens include poverty, high unemployment, air and water pollution, presence of hazardous wastes as well as high incidence of asthma and heart disease" (**https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/disadvantaged-communities**). This terminology is also used by the White House Council on Environmental Quality.

Exhibit 31 **Additional resources that support aligned resource planning**

Resource, authoring organization, when published	Overview
"**Climate Change and the 2021 Power Plan Workshop**," Northwest Power and Conservation Council, May 2019	This online resource shows the agenda from the System Integration Forum's Climate Change and 2021 Power Plan workshop with live links to resources that describe climate impacts on planning.
Considerations for Resilience Guidelines for Clean Energy Plans, for the Oregon PUC and Oregon Electricity Stakeholders, September 2022	This report, prepared for the Oregon PUC, provides an overview of approaches to incorporating resilience in planning.
"**Electricity Reliability & Resilience**" website, Berkeley Lab	This online resource has past projects and publications on electricity reliability analysis and includes such topics as improving reliability performance data and metrics, evaluating reliability trends, and assessing the economic value of reliability to customers.
Redefining Resource Adequacy for Modern Power Systems, Energy Systems Integration Group (ESIG), 2021	This report provides six guiding principles for practitioners to use when redefining resource adequacy to meet the needs of the grid under changing chronological grid operations and correlated events.
"**Integrated, Resilient Distribution Planning**," NARUC webinar, May 2020	This presentation has technical information, frameworks, and resources for improving resilience in distribution system planning.
"**Innovations in Electricity Modeling: Planning for Climate Variability,**" National Council on Electricity Planning (NCEP) and Berkeley Lab, October 2021	This online resource has a four-part series of virtual trainings, one of which covers planning for climate variability: • Load forecasting for transmission and distribution system planning • Resource, asset, and contingency planning
"**Interruption Cost Estimate (ICE) Calculator,**" Berkeley Lab	This online tool supports reliability planning and can be used to estimate interruption costs and the value of reliability improvement.
"**Multi-objective Decision Planning (MOD-Plan) for Equity, Resilience, and Decarbonization**," Sandia National Laboratories, US Department of Energy (DOE), and PNNL	This project is intended to develop a framework for multi-objective decision-making across traditional planning objectives and energy justice and equity, resilience, and decarbonization.

Resource, authoring organization, when published	Overview
Resource Adequacy Primer for State Regulators, NARUC, July 2021	This report outlines different state and market approaches to resource adequacy and concludes with two current and emerging issues: measuring resource adequacy with an evolving resource mix and changing demand characteristics and the interplay between regional and state planning.
Utility Investments in Resilience of Electricity Systems, Berkeley Lab and others, April 2019	This report is one of a series of DOE-funded reports that reflects different perspectives of electricity system stakeholders on critical questions; this report is on resilience investments and includes questions of cost, responsibility, planning strategies, and future opportunities from state regulators, utilities, and consumers.

7. Conclusion

Ultimately, we hope that utilities and regulators will use this opportunity — when their resource planning processes are being stretched and challenged — to consider how resource planning may need to be reimagined.

To ensure that IRPs can remain trusted, comprehensive, and aligned, utilities and regulators have an opportunity to take a step back and realign on the purpose, scope, roles, and tools used in planning before making many piecemeal enhancements.

After aligning on priority enhancements, look to examples across the country that other utilities and regulators have tested. Yet the list of questions that are coming up in the process of reimagining planning is constantly growing, and the list of examples we've shared is incomplete. Utilities and regulators should continue to ask big questions about the future of resource planning, try new approaches, and share their results.

Appendix: Resource Tables

State	Region	Sources
Alabama	South	• **State Guide to Utility Energy Efficiency Planning** • **Commission Order**: "Consideration of Sections 532 and 1307 of the Energy Independence and Security Act of 2007"
Colorado	West	• **Rules Regulating Electric Utilities**
Georgia	South	• **Rules and Regulations:** Integrated Resource Planning
Michigan	Midwest	• **Commission Opinion and Order** • **"Section 460.6t Integrated resource plan"**
Minnesota	Midwest	• **Minnesota Administrative Rules** • **2022 Minnesota Statutes**
New Mexico	Southwest	• **PRC Ruling**: "Integrated Resource Plans for Electric Utilities"
North Carolina	East	• **NCUC Rules**
Oregon	Pacific Northwest	• **IRP Guidelines** • **IRP Administrative Rules** • **Competitive Bidding Rules**
South Carolina	South	• **South Carolina Code of Laws**: "Energy Supply and Efficiency"
Utah	West	• **Utah Code**: "Resource Plans and Significant Energy Resource Approval"
Washington	Pacific Northwest	• **Washington Administrative Code:** "Content of an Integrated Resource Plan" • **Washington Clean Energy Transition Act**
Wyoming	West	• **Guidelines Regarding Electric IRP** • **Administrative Rules**

Endnotes

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EXHIBIT MDD-4

Docket No. 22-11032
Interwest Energy Alliance
Prefiled Direct Testimony of Mark Detsky, Esq.

Colorado Resource Plan Process

Process

Phase I:
- Establish resource need
- Set modeling assumptions
- RFP parameters and model PPAs

Phase II:
- Request for proposals
- Assemble portfolios
- Commission approval
- Contract and build

Repeat every ~4 years

Features

- Robust litigation of Phase I aspects
- All source solicitation process
- Expedited Phase II to move forward quickly on live bids
- Two PUC decision checkpoints; independent evaluator
- Encourages strong participation of both IPP and utility projects
- Fair playing field across ownership and technology types
- Adaptable to new policy objectives (e.g. climate, labor, just transition)

Results

2017 RFP
- >400 bids
- ~60 GW bids
- Record low bids

Total Clean Investment Today
- 4000 MW Wind
- 730 MW Solar*

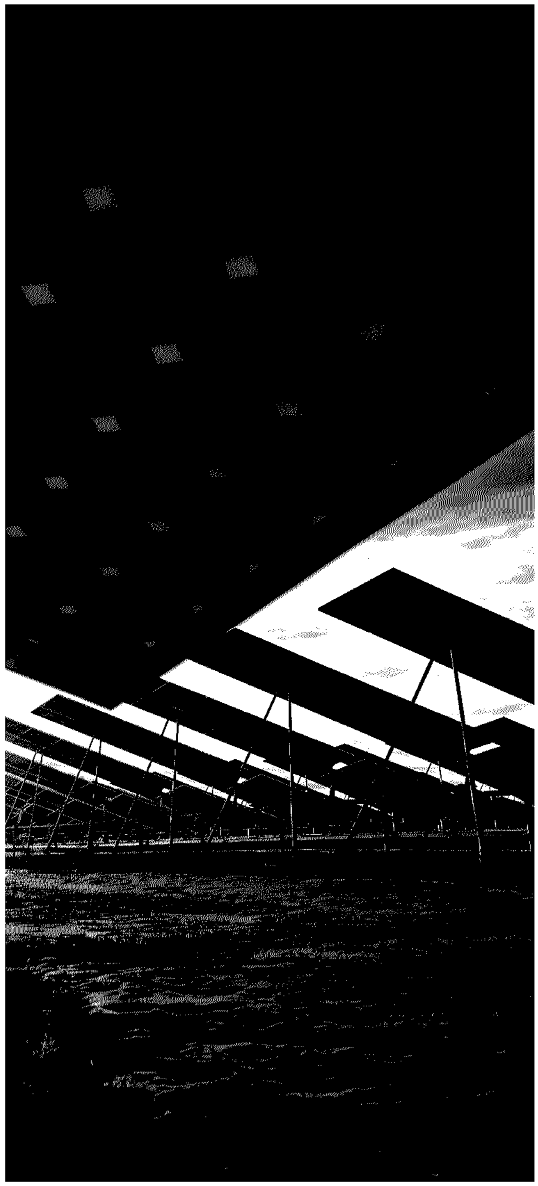
(*Not counting DG)

The Future: Clean Energy Plan
- ~85% CO_2 reduction
- ~80% RE gen

EXHIBIT MDD-5

Docket No. 22-11032
Interwest Energy Alliance
Prefiled Direct Testimony of Mark Detsky, Esq.

NOTICE OF CONFIDENTIALITY:
A portion of this document has been filed under seal.
Pages 23, 42, 47, 48, 52, and 67.



Public Service Company of Colorado

2016 Electric Resource Plan

120-Day Report

HIGHLY CONFIDENTIAL VERSION

(CPUC Proceeding No.16A-0396E)

June 6, 2018

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1.0 Executive Summary

Public Service Company of Colorado's ("Public Service" or the "Company") preferred Colorado Energy Plan Portfolio ("Preferred CEPP") provides an attractive path for our customers and the State of Colorado. This 120-Day Report presents an opportunity for the Commission to continue the transformation of the Public Service generation portfolio in a manner that simultaneously achieves economic and environmental benefits. Through approval of the cost-effective resource plan presented below, the Commission can harness Colorado's natural resources to dramatically reduce carbon and other emissions, and deliver value for Coloradans in the form of economic development and long-term savings to customers on their electric bills. The benefits of the Preferred CEPP are substantial and include:

- Customer savings of more than $200 million on a net present value basis relative to the business as usual Preferred ERP plan (filling 450 MW need and continuing operations of Comanche 1 and Comanche 2);
- Statewide investment of $2.5 billion across eight different Colorado counties;
- Nearly 55% renewable energy by 2026 driven by over 1,800 MW of new wind and solar generation;
- Deep emissions reductions that, by 2026, include nearly 60 percent lower CO_2 emissions and 90 percent lower SO_2 and NO_X emissions than 2005 levels;
- Increased operational flexibility and reliability by pairing increased renewable generation with dispatchable battery storage and flexible gas generation; and,
- A beneficial path forward for Pueblo County, a long-time host community for the Comanche plant.

Our Preferred CEPP is the product of the Commission's oversight in developing a process and framework to allow for the robust evaluation of the Colorado Energy Plan as well as the work of sixteen diverse parties, each of whom worked to develop and ultimately coalesced around the possibility of a transformative plan – a plan that can now come to fruition and is presented in this 120-Day Report. Notably, the Plan produces greater savings than contemplated by the Stipulation. The Preferred CEPP consists of the following course of action:

- Accelerating the retirement of Comanche 1 and Comanche 2;
- Adding 1,100 MW of wind to our system;
- Adding 700 MW of solar to our system;

- Introducing 275 MW of battery storage to the system (all embedded in solar plus storage projects); and

- Ensuring system reliability by utilizing 380 MW of existing flexible gas resources.

Our Preferred CEPP was the beneficiary of a Phase II competitive solicitation that generated over 400 bids, including an unprecedented number of diverse and low-cost bids. After assessing thousands of bid combinations and working closely with the Independent Evaluator, the Company synthesized this information and developed two primary paths to help frame the decision at hand for the Commission and other interested parties – which portfolio should be selected as the final cost-effective resource plan. Path one is that of the Electric Resource Plan portfolio with its 450 MW resource need and the continued operations of Comanche 1 and Comanche 2. Path two is the Colorado Energy Plan that incorporates the early retirement of 660 MW of coal-fired generation at Comanche 1 and Comanche 2. These two paths result in the two foundational portfolios for this 120-Day Report: the Preferred ERP and the Preferred CEPP. While the economic benefits of both approaches are reasonable, the compelling aspect of the Preferred CEPP is that it delivers lower costs with substantial environmental and renewable energy gains that are greater than in the traditional ERP as presented here.

The 120-Day Report contains information and analysis to allow for a comprehensive evaluation of these two paths, consistent with Commission directives. In particular, this 120-Day Report provides a robust body of data and detailed information to allow the Commission a full record on which to identify a cost-effective portfolio that lays out a prudent path forward for Colorado. The suite of data to evaluate the portfolios includes various sensitivities including gas price, discount rate, and carbon price along with other portfolios including least-cost portfolios, and other relevant data points. The 120-Day Report also provides the Commission with the information it needs to evaluate different sizes of portfolios based on the level of resource need that can be satisfied with bids submitted in this competitive solicitation.

After extensive evaluation using the criteria established by the Commission, the Company is excited to present the Preferred CEPP as the recommended path forward. The Preferred ERP provides a reasonable and cost-effective path forward for the Public Service system and State of Colorado, but the Preferred CEPP does much more. The Preferred CEPP continues the cost-effective transition of our generation fleet to cleaner more diverse resources while delivering tangible benefits to our customers and state and local communities. The Preferred CEPP includes a strong commitment to new wind and solar resources, takes a large step into the utilization of battery storage, and leverages the use of existing gas generation.

Moreover, the Preferred CEPP provides a wide range of benefits including customer savings, beneficial environmental impacts, generation technology and geographic diversity, balanced ownership between utility and IPPs (and among several different

IPPs), system operational benefits, economic development benefits, and host community benefits. All of these factors support our recommendation, and we believe further support a finding from the Commission that the Preferred CEPP is "a designated combination of new resources that the Commission determines can be acquired at a reasonable cost and rate impact" and therefore a cost-effective resource plan.[1]

While the benefits of the Preferred CEPP are described in more detail in the following section and supported throughout this 120-Day Report, below is a brief summary of the plan and related benefits:

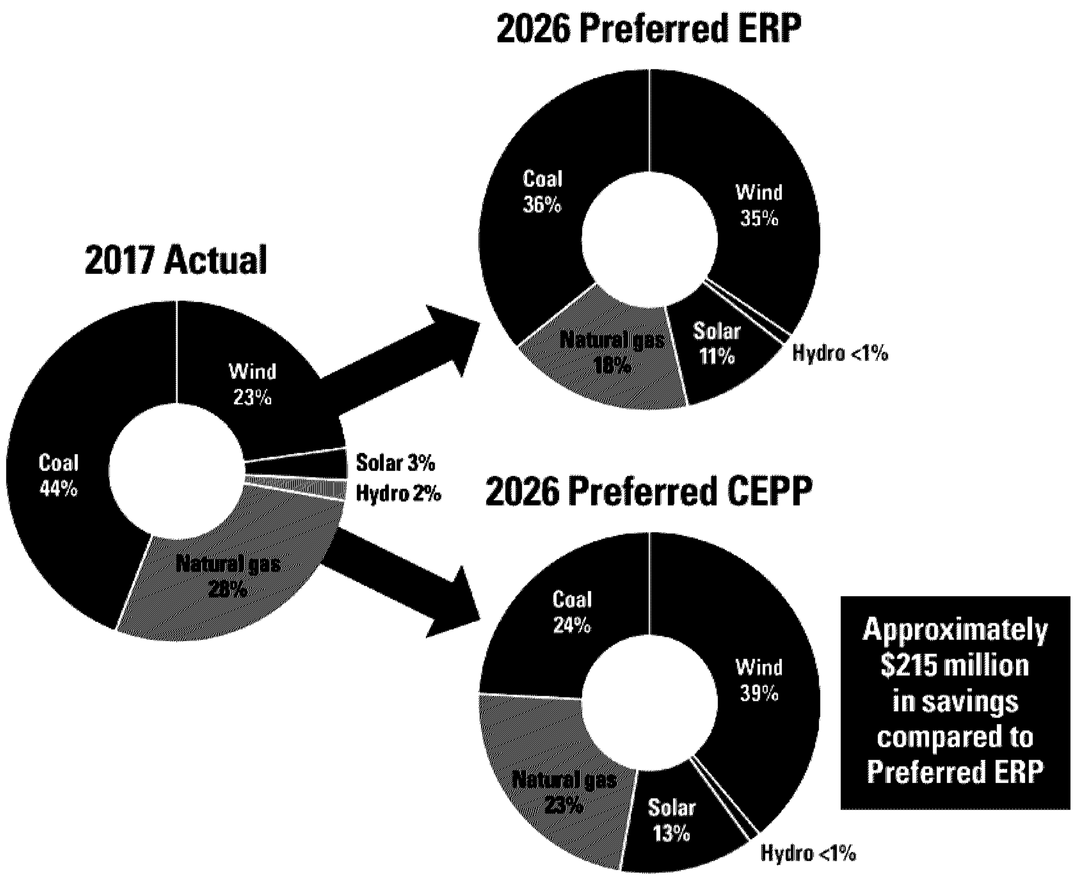
- Preferred CEPP Summary. The Preferred CEPP offers diversity of technologies, with approximately 1,100 MW of wind, 700 MW of solar, 275 MW of storage (all embedded in solar plus storage projects), and 380 MW of existing gas resources. The Preferred CEPP provides balance in generation ownership. The Company will own 27% of the renewable resources (500 MW of wind) and 58% of dispatchable and semi-dispatchable resources (380 MW of gas generation). While less than the ownership targets contemplated in the Stipulation, the Company believes that moving forward with a transition to clean energy is preferred. We believe the Preferred CEPP achieves the "value of maintaining both robust utility and IPP ownership," as acknowledged by the Commission as an important resource planning goal.[2]

- Customer savings. The Preferred CEPP is projected to save approximately $215 million on a present value basis as compared to the Preferred ERP.[3] Further, as set forth in this document, the Company believes there are additional opportunities that could drive further savings for customers. The approximately $215 million in savings is a reasonable yet conservative figure for the Commission to use in determining a cost-effective resource plan in this proceeding.

- Clean energy benefits. Many customers and communities are seeking more renewable energy. Under the Preferred CEPP, we would achieve nearly 55% renewable energy by 2026. The energy mix would include a diverse blend of generation, and also add flexible battery resources to the system.

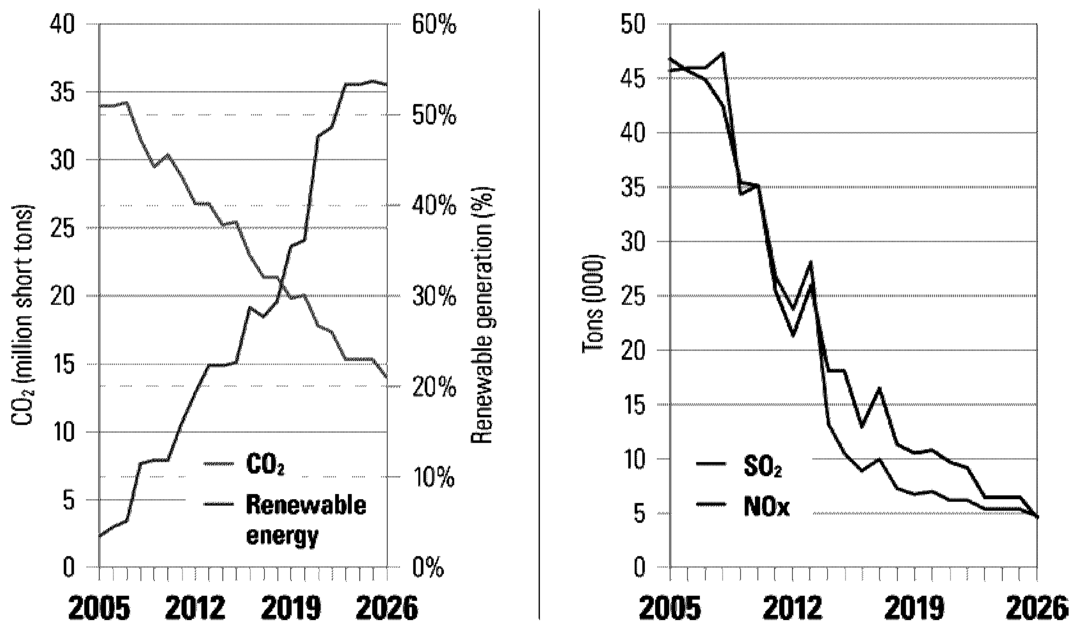
[1] Rule 3602(c).
[2] Decision No. C18-0191, at ¶ 50 (mailed Mar. 22, 2018).
[3] Projected savings over the Planning Period are $213 million on a present value basis using the replacement backfilling method and $374 million on a present value basis using the annuity backfilling method. These savings were calculated without any carbon cost adders.

Estimated Energy Mix Under the Preferred CEPP



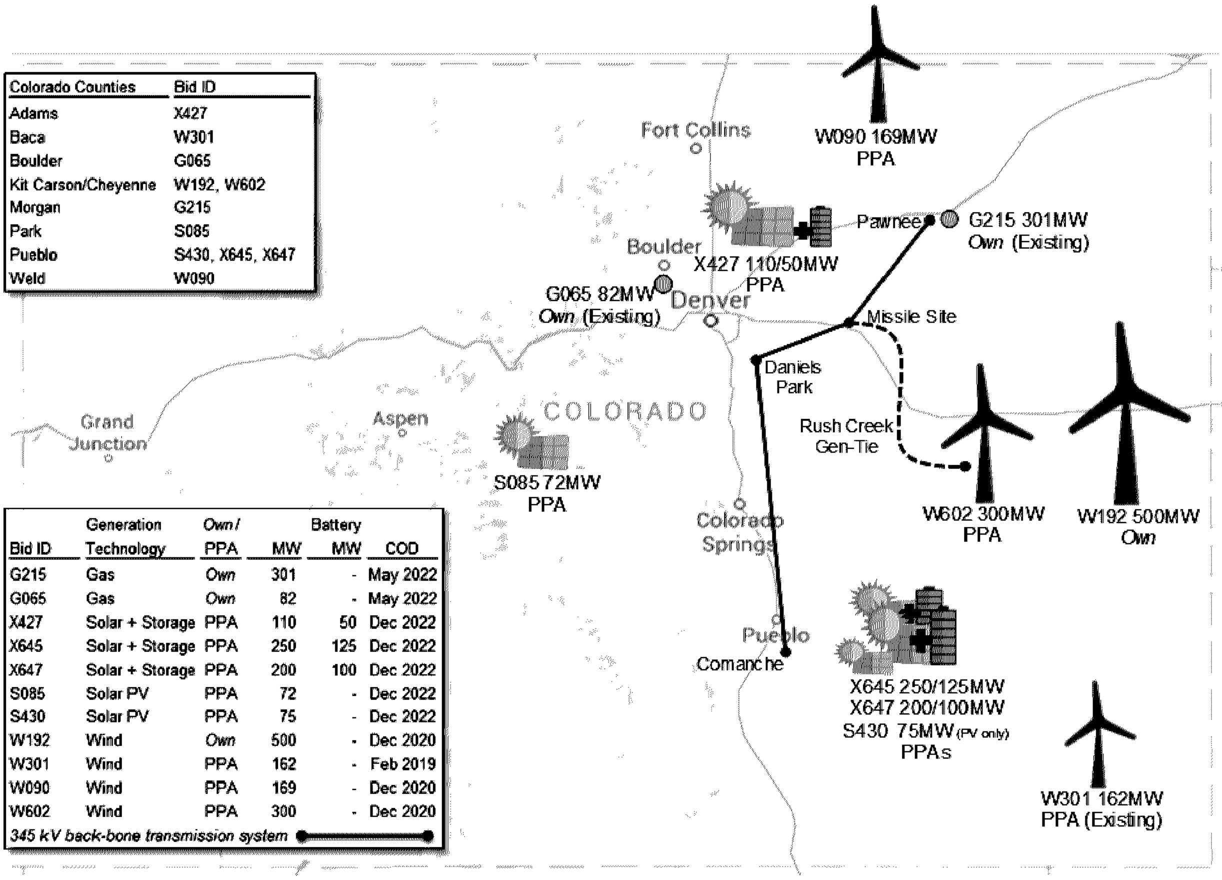
- Environmental benefits. The Preferred CEPP can deliver significant cost savings while making deep cuts in the Company's CO_2, SO_2, and NO_X emissions. With the implementation of the Preferred CEPP, we estimate Public Service's CO_2 emissions will be approximately 60% lower in 2026 than in 2005, and we also anticipate that SO_2 and NOx emissions would be 90% lower than 2005 by 2026.

Energy Transition: CO_2, SO_2 and NO_X Reduction and Renewable Energy Growth Under the Preferred CEPP



- Geographic diversity. The Preferred CEPP offers substantial geographic diversity, with selected generation resources in eight different Colorado counties. The plan includes approximately 1,100 MW of new wind resources in the northern and eastern part of the State of Colorado and over 500 MW of new solar and 225 MW of battery storage resources in the southern half of the State (with the balance of solar in the northern and western part of the State). The Figure below shows a map depicting the dispersion of the Preferred CEPP resources across different regions of Colorado.

Preferred CEPP Generation Locations



Colorado Counties	Bid ID
Adams	X427
Baca	W301
Boulder	G065
Kit Carson/Cheyenne	W192, W602
Morgan	G215
Park	S085
Pueblo	S430, X645, X647
Weld	W090

Bid ID	Generation Technology	Own / PPA	MW	Battery MW	COD
G215	Gas	Own	301	-	May 2022
G065	Gas	Own	82	-	May 2022
X427	Solar + Storage	PPA	110	50	Dec 2022
X645	Solar + Storage	PPA	250	125	Dec 2022
X647	Solar + Storage	PPA	200	100	Dec 2022
S085	Solar PV	PPA	72	-	Dec 2022
S430	Solar PV	PPA	75	-	Dec 2022
W192	Wind	Own	500	-	Dec 2020
W301	Wind	PPA	162	-	Feb 2019
W090	Wind	PPA	169	-	Dec 2020
W602	Wind	PPA	300	-	Dec 2020

345 kV back-bone transmission system

- Use of existing and new infrastructure. Geographic and technological diversity combine with the use of existing infrastructure and development of necessary new transmission infrastructure to provide the reliability customers know and expect from Public Service.

- Economic development benefits. The Preferred CEPP supports the economic vitality of our state and local communities. It provides economic development benefits across Colorado with approximately 2,500 MW of generation assets (including battery storage) developed or acquired in different regions of Colorado, totaling approximately $2.5 billion in generation investment alone.

- Host community benefits. The Preferred CEPP is a catalyst for benefits to Pueblo, the long-time host community for Comanche 1 and Comanche 2. It would result in the development of high levels of new solar and battery storage and other supporting infrastructure in the Pueblo area, benefit the Pueblo County "1A Community Improvement Program," and provide the ability for the Company to enable an EVRAZ contract to help keep this anchor of the Pueblo business community in Colorado. The contract and net metered on-site solar facility (between approximately 200 MW and 240 MW), combined with other incentives provided to EVRAZ by state and local government authorities, could enable substantial investments in new production facilities at the EVRAZ steel mill in Pueblo as well as on-site solar, which will increase the overall economic impact of our plan.

Recognizing the importance of providing the Commission with good alternatives to consider, and that the Preferred CEPP would add resources in this Resource Acquisition Period ("RAP") that are not needed until the early retirement of Comanche 2 at the end of 2025, the Company is receptive to the Commission's consideration of a slightly different CEPP that would effectively defer one solar with battery storage project for acquisition to the next ERP. We fully expect that this approach would achieve the same environmental benefits outlined above, but it would provide greater economic benefits and allow a staged introduction of new battery storage technology. This "Alternative CEPP" would capitalize on and maximize acquisition of 100% PTC wind, which we do not anticipate being available in the next ERP cycle. However, it would implement a phased, but still progressive approach to the acquisition of solar and solar with battery storage projects, which we anticipate will continue to be available at even lower prices in the next ERP cycle with the full 30% Investment Tax Credit ("ITC"). While this last solar with battery storage project is cost-effective, it results in the acquisition of capacity before it is needed by the system. Even assuming the price of solar and storage remain flat through the next ERP, delaying this last contract until the next ERP cycle would save customers approximately $20 million. As noted above, we expect these prices to continue their decline so this savings estimate is conservative. This Alternative CEPP would result in the acquisition of 250 MW less of solar and 125 MW less of battery storage than the Preferred CEPP, but would still result in the addition of 1,100 MW of wind, 450 MW of solar, 150 MW of battery storage (again embedded in solar plus battery storage projects), and 380 MW of existing gas resources in this ERP.

There are many reasons, outlined above and throughout this 120-Day Report, that the Commission *should* approve the Preferred CEPP or its alternative. Here we note that the Commission *can*, consistent with Colorado law, approve the Preferred CEPP. The State of Colorado prioritizes economics and environment in its energy mix and employs a cost-effectiveness standard in resource planning. The Preferred CEPP is undoubtedly a cost-effective resource plan—and one that delivers economic and environmental benefits that can transform the energy landscape of Colorado.

Accordingly, the Company requests the Commission find the Preferred CEPP to be a cost-effective resource plan and approve it by the Commission's Phase II Decision in this proceeding. This 120-Day Report provides extensive detail and support for the conclusion that the Preferred CEPP is the right plan for our customers, our stakeholders, the Company, and the State.

The remainder of the Report proceeds as follows:

- **Section 2.0** provides an overview of the preferred portfolios;
- **Section 3.0** describes how the Company coordinated with the Independent Evaluator through the solicitation process;
- **Section 4.0** sets forth the analysis supporting the preferred portfolios;
- **Section 5.0** details the key modeling inputs, assumptions and methodologies;
- **Section 6.0** provides an overview of the Phase II process; and
- **Section 7.0** includes a conclusion and proposal for next steps.

2.0 Overview of Preferred Portfolios

This section of the 120-Day Report provides an overview of and background on key characteristics associated with the Preferred CEPP, the Alternative CEPP described in the Executive Summary, and the Preferred ERP.

2.1 The Preferred Colorado Energy Plan Portfolio

The Preferred CEPP provides an attractive path for our customers and the State of Colorado. It is an opportunity for this Commission to continue the transition of the Public Service generation fleet, bolster economic development across Colorado, *and* lower customer bills. The extensive body of information provided in this report demonstrates that the Preferred CEPP portfolio is a cost-effective resource plan. The Commission can approve the CEPP, and it should. It can because Colorado law gives the Commission flexibility and discretion to look beyond the narrow parameters of "least cost" to the broader picture of what is good for customers, stakeholders, the Company, and the State of Colorado. The Preferred CEPP is good for customers, stakeholders, and the State of Colorado. It will result in approximately $2.5 billion of generation investment and $200 million of transmission investment across the State, with Public Service's investment at approximately $1 billion, and attendant economic development benefits across numerous Colorado counties and the State generally. It is projected to save customers over $200 million relative to the Preferred ERP. And it will also dramatically reduce emissions by 2026.

The Preferred CEPP delivers economic and environmental benefits by adding 1,838 MW of renewable generation, paired with 275 MW of battery storage, and 383 MW of existing gas assets, all while retiring 660 MW of coal-fired generation (approximately one-third of the Company's remaining coal fleet). This approach furthers the development of a flexible system that takes advantage of intermittent renewable resources while adding battery storage and existing gas generation to our existing fleet of dispatchable resources that includes pumped hydro storage, natural gas combined cycle, and gas combustion turbine peaking resources. Beyond bolstering reliability and environmental performance, this increasingly diverse fuel mix serves as a customer protection by acting as a natural hedge against commodity prices. Public Service also forecasts that implementation of the Preferred CEPP can be accomplished at an annualized rate of less than 1% through 2030.

This section provides further detail regarding the benefits associated with the Preferred CEPP, and these benefits show the Company has identified a "cost-effective resource plan" for Commission consideration — the stated goal of the ERP process. Below we identify the customer savings, environmental benefits, clean energy benefits, diversity benefits, economic development benefits, and host community benefits that illustrate what the Preferred CEPP can provide to customers, communities, and the State of Colorado. These benefits are central to the Commission's charge to evaluate cost-effectiveness based on quantitative and qualitative factors. Indeed, the Commission reinforced the scope of the cost-effectiveness evaluation used in the ERP process in its order allowing the CEPP to be brought forward, confirming that "[t]he Phase II process is designed to consider both quantitative (i.e., modeled PVRR cost comparison between portfolios) and qualitative factors such as jobs or certain environmental benefits." The quantitative and qualitative factors outlined below support a finding by the Commission that the Preferred CEPP is cost-effective and merits approval.

Customer Savings of the Preferred CEPP

The Preferred CEPP saves money for customers. Indeed, it is projected to save between $213 million and $374 million on a present value basis as compared to the preferred ERP 450 MW portfolio.[4] These two portfolios are the foundational portfolios for this 120-Day Report, and the key metrics of each are set forth in the table below.

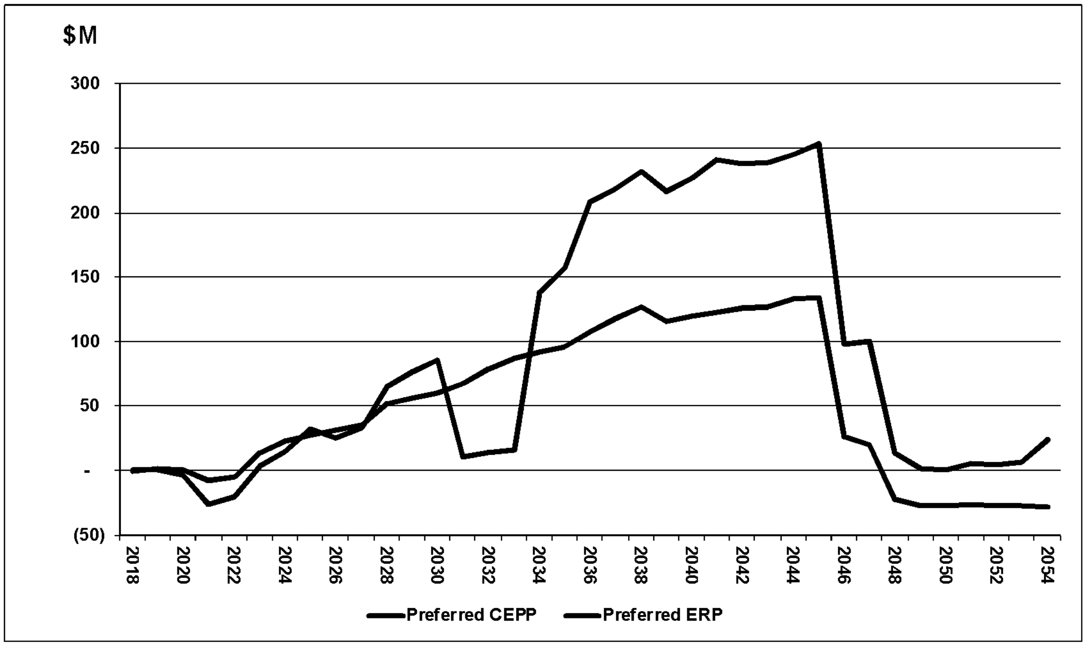
Table 1 - Preferred CEPP and Preferred ERP Portfolio

	Preferred ERP	Preferred CEPP
Comanche 1 & 2 Retire Year	2033/2035	2022/2025
Targeted Resource Acquisition (MW)	450	1,110
Portfolio Generation		
Wind (MW)	789	1,131
Solar (MW)	322	707
Battery Storage (MW)	50	275
Gas (MW)	301	383
Portfolio Firm Capacity (MW)	554	993
Total Generation Investment ($M)	$1,460	$2,550
Company Ownership (% of Nameplate)		
Eligible Energy Resources (%)	0%	27%
Dispatchable/Semi-Dispatchable (%)	86%	58%
Total Transmission Investment ($M)	$175	$204
2016 – 2054 Planning Period PVRR	$34,901	$34,687
PVRR Savings vs. Preferred ERP ($M)	**-**	**$213**
Total Investment ($M)	$1,636	$2,754
2026 CO_2 Reduction (%)	47%	59%

Another key comparison illustrating the savings to customers of our Preferred CEPP is as against the costs of the All Thermal ERP portfolio – a portfolio that meets the 450 MW need solely with gas-fired projects. The comparison chart below shows savings to customers on an annual basis associated with the Preferred ERP and Preferred CEPP as compared to the All Thermal ERP portfolio.

[4] Projected savings over the Planning Period are $213 million on a present value basis using the replacement backfilling method and $374 million on a present value basis using the annuity backfilling method.

Figure 1 - Annual Savings (Cost) of Preferred ERP and Preferred CEPP to All Thermal ERP



On a present value basis the Preferred ERP saves $510 million as compared to the All Thermal ERP portfolio. The savings of the Preferred CEPP against the All Thermal ERP portfolio are even more substantial, saving customers $723 million on a present value basis over the Planning Period.

<u>Clean Energy Benefits</u>

Our Colorado customers want clean energy at a reasonable price. In fact, we have surveyed individual customers, and a majority of the Company's customers and citizens of Colorado surveyed support clean energy progress and emissions reduction — a trend seen in statewide surveys as summarized in the graphic below. The Preferred CEPP supports exactly that outcome: transitioning to clean energy while lowering customer costs and continuing our unwavering commitment to system reliability.

Figure 2 - Results From Colorado Statewide Voter Survey: Percentage of Survey Respondents Supporting These Statements, June 2017

57%
Coal use should be decreased

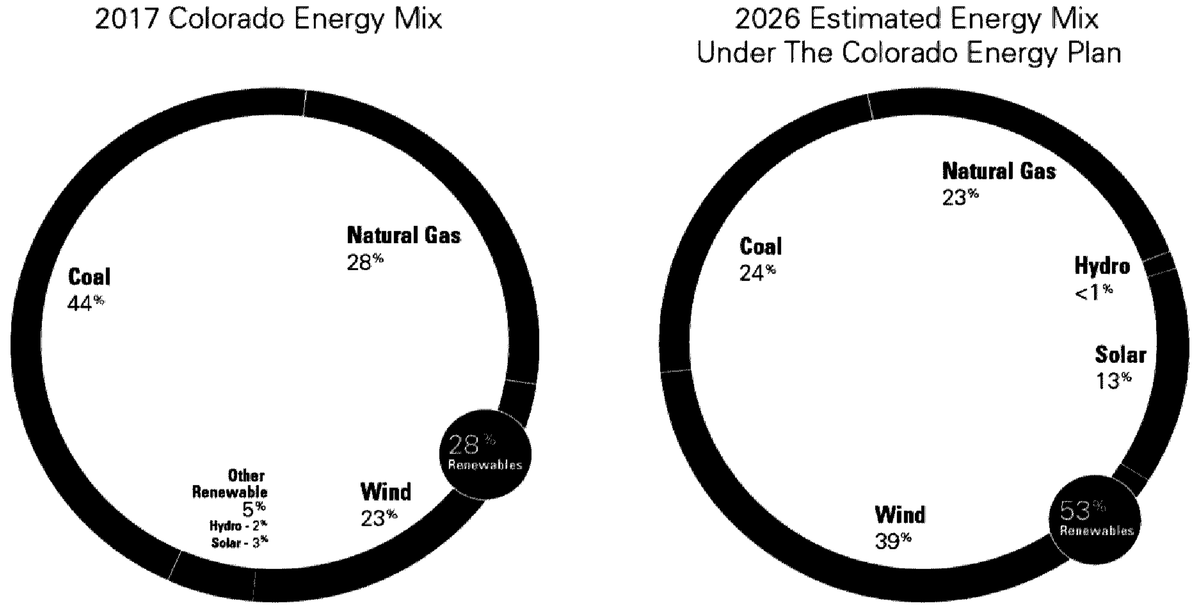
83%
Colorado utilities should increase clean renewable energy if it means no increase in energy costs

89%
The state of Colorado and utilities should reduce carbon emissions while providing reliable and affordable energy

95%
The state of Colorado and utilities should work together to achieve the most significant increases in the use of clean renewable energy that can be accomplished while providing reliable and affordable energy

The Preferred CEPP would transform the energy mix we use to provide electric service to our customers. The figure below shows the Company's projected energy mix in 2026 with the Preferred CEPP as compared to the 2017 energy mix. By 2026, we will serve customers with an energy mix that includes nearly 55% renewable energy, up from 28% in 2017. Natural gas remains relatively steady in the fuel mix, going from 28% in 2017 to 23% in 2026. Coal would decrease substantially from 44% in 2017 to 24% in 2026. Our energy mix would remain balanced and diverse, while at the same time continuing its transformation into one of the most progressive energy portfolios in the country.

Figure 3 - Current Energy Mix Versus Preferred CEPP 2026 Energy Mix



<u>Environmental Benefits of the Preferred CEPP</u>

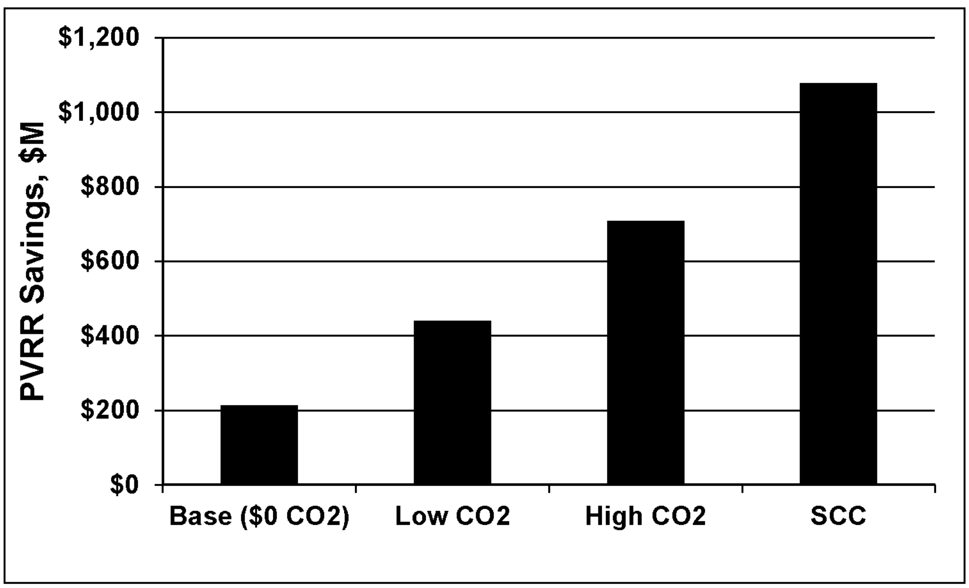
The environmental benefits of the Preferred CEPP are as compelling as its economic benefits. The Preferred CEPP can deliver significant cost savings while simultaneously making deep cuts in our CO_2, SO_2, and NO_X emissions. With the implementation of the Preferred CEPP, we estimate Public Service's CO_2 emissions will be approximately 60% lower in 2026 than in 2005, and we also anticipate that SO_2 and NOx emissions could be about 90% lower than 2005 by 2026. These reductions surpass the goals set forth in Executive Order D 2017-015, Supporting Colorado's Clean Energy Transition, issued by Governor John Hickenlooper on July 11, 2017, as set forth in Table 2 below.

Table 2 - Preferred CEPP and Executive Order D 2017-015 Emission Targets

Exec. Order Target		Colorado Energy Plan Portfolio Estimated Result
Economy-wide multi-sector GHG target	26% below 2005 by 2025	Public Service's emissions reductions would achieve about half of the total state economy's reduction need as expressed in tons by 2025. The Company would achieve 18 million short tons of reduction against a goal that requires 35 million short tons of reduction by 2025.
Electric sector CO_2 target	25% below 2012 by 2025	42% below 2012 by 2025
Electric sector CO_2 target	35% below 2012 by 2030	48% below 2012 by 2026.

The Preferred CEPP also acts as a hedge against future environmental regulation — an express concern of this Commission. To help quantify that risk, the Commission ordered the Company to run sensitivities based on varying levels of future CO_2 costs. These sensitivities included a low CO_2 cost case, high CO_2 cost case, and social cost of carbon case.[5] Taken together, the results show that under all scenarios, the Preferred CEPP has significant value as a hedge against future environmental regulations.

Figure 4 - Preferred CEPP Savings Compared to Preferred ERP Under Future CO_2 Costs



[5] See Appendix E, Modeling Assumptions Update, for more detail on the low CO_2, high CO_2, and social cost of carbon sensitivity cases.

Diversity of the Preferred CEPP

While the Preferred CEPP delivers significant customer savings and environmental benefits, it also introduces additional geographically diverse generators to the system and, with it, reliability benefits to the system. The table below identifies the generation diversity of the Preferred CEPP by county.

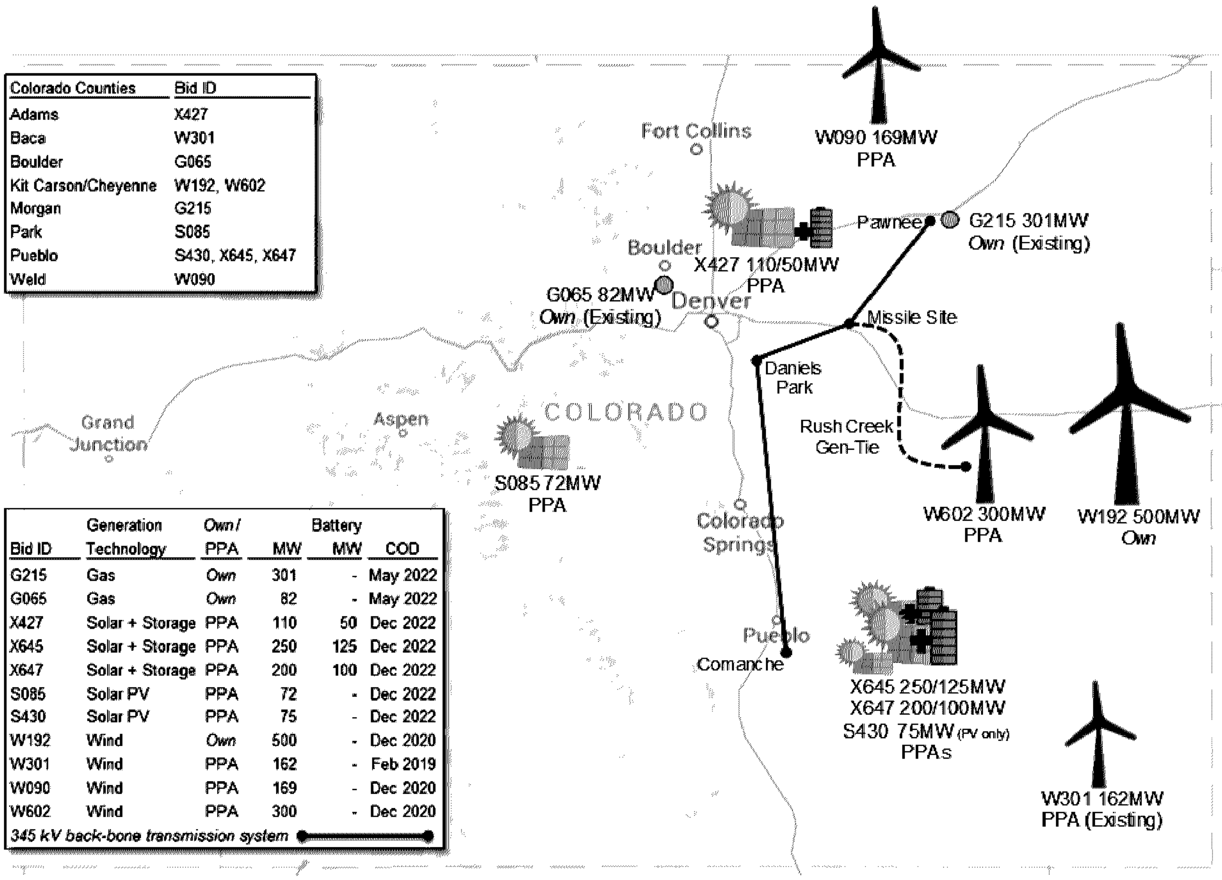
Table 3 - Preferred CEPP Generation Diversity

County	MW
Adams	110 MW (solar), 50 MW (storage)
Baca	162 MW (wind repower of existing)
Boulder	82 MW (existing gas)
Kit Carson/Cheyenne[6]	800 MW (wind)
Morgan	301 MW (existing gas)
Park	72 MW (solar)
Pueblo	525 MW (solar), 225 MW (storage)
Weld	169 MW (wind)

The figure below provides a map showing the dispersion of the Preferred CEPP resources across different regions of Colorado.

[6] The two wind projects in this area of Colorado cover territory in both Kit Carson and Cheyenne counties; therefore, these counties are grouped together.

Figure 5 - Preferred CEPP Generation Locations



Colorado Counties	Bid ID
Adams	X427
Baca	W301
Boulder	G065
Kit Carson/Cheyenne	W192, W602
Morgan	G215
Park	S085
Pueblo	S430, X645, X647
Weld	W090

Bid ID	Generation Technology	Own / PPA	MW	Battery MW	COD
G215	Gas	Own	301	-	May 2022
G065	Gas	Own	82	-	May 2022
X427	Solar + Storage	PPA	110	50	Dec 2022
X645	Solar + Storage	PPA	250	125	Dec 2022
X647	Solar + Storage	PPA	200	100	Dec 2022
S085	Solar PV	PPA	72	-	Dec 2022
S430	Solar PV	PPA	75	-	Dec 2022
W192	Wind	Own	500	-	Dec 2020
W301	Wind	PPA	162	-	Feb 2019
W090	Wind	PPA	169	-	Dec 2020
W602	Wind	PPA	300	-	Dec 2020

345 kV back-bone transmission system

The Preferred CEPP also provides balance in generation ownership. The Company will own 27% of the renewable resources (all wind) and 58% of dispatchable and semi-dispatchable resources (all gas). While the Preferred CEPP results in utility ownership levels short of ownership targets envisioned in our Stipulation (i.e., a target of 50% of eligible energy resources and 75% of dispatchable and semi-dispatchable resources), we believe this represents an appropriate path forward for the Commission that preserves diversity of ownership. With these additions, the Company would own approximately 20% of the overall renewable resources on the Public Service system.

The Commission recognizes the value of balanced ownership, and the Preferred CEPP provides that balance. The Commission's Decision No. C18-0191 at Paragraph 50 hit this point directly, where the Commission held:

> We agree with past Commission statements raised by Public Service recognizing the value of maintaining both robust utility and IPP ownership.

The Commission further noted that utility ownership is particularly important where, as here, the Company has brought forward a "voluntary proposal to retire Comanche 1 and 2" and advanced a plan that included "other concessions from Public Service such as restricted utility-builds, deferral of utility construction under Rule 4 CCR 723-3-3660(h), a requirement for cost neutrality or savings of the CEP Portfolio, and the presenting of the CEP Portfolio within an ERP proceeding." The geographic, resource and ownership diversity is yet another reason why the Preferred CEPP warrants approval.

Use of Existing and New Infrastructure

The Preferred CEPP leverages the existing or already planned transmission network and contemplates additional transmission investments to deliver these resources to load. As we continue the transition of the Company's generation fleet and replace aging coal-fired generation with significant amounts of low-cost renewables, maintaining the reliability of our system is critical—and, for our customers, non-negotiable. Transmission takes on an increasingly important role in both enabling access to very cost-effective resources located in the most beneficial renewable areas of the state and supporting the ongoing reliability needs of the system. Notably, the cost savings analysis includes the transmission investments—meaning, we have accounted for those investments in our modeling and still show significant customer savings from the Preferred CEPP.

And while new infrastructure investments are required, our approach also utilizes existing infrastructure to the maximum extent practicable. For example, existing gas generation is acquired to maximize the use of existing electric interconnection and natural gas supply infrastructure, as well as minimize the environmental impacts and permitting associated with new gas construction. While the Preferred CEPP contains no new gas generation and utilizes only existing, low-cost gas projects, the use of existing infrastructure is not limited to gas delivery and generation only. Indeed, the Preferred CEPP also contains the repowering of an existing wind project in southeastern Colorado. This collective use of existing infrastructure and generation helps to create a Preferred CEPP that is cost-effective and saves money for customers.

Economic Development Benefits of the Preferred CEPP

Adding geographic diversity to the system not only supports reliability, but it also benefits the State of Colorado through dispersed investments supporting the economic vitality of communities in numerous regions of Colorado. The statewide economic attributes of the Preferred CEPP are significant — and, for some areas of our State, critical. The table below identifies the dispersed generation investment of the Preferred CEPP by county.

Table 4 - Preferred CEPP Generation Investment Location

County	Investment ($M)[7]
Adams	$140
Baca	$240
Boulder	$20
Kit Carson/Cheyenne[8]	$1,110
Morgan	$50
Park	$90
Pueblo	$670
Weld	$230

These projects will help to create construction jobs in the development of new projects and necessary delivery infrastructure. There will also be on-going jobs and employment opportunities at new and existing generators. This investment and these opportunities will help drive both short- and long-term economic development benefits for these counties and communities in Colorado.[9] The Company also stands behind its commitments in the Stipulation, including its commitments to use union labor for any conversion of the generators at Comanche 1 and Comanche 2 to synchronous condensers. In addition, the acquisition of existing gas generation by the Company through this plan will expand the opportunity for union labor to operate and maintain these plants.

Host Community Benefits of the Preferred CEPP

In evaluating the Preferred CEPP, the Commission considers qualitative factors.[10] One of the critical qualitative benefits delivered by the Preferred CEPP is a renewed commitment to our long-time host community of Pueblo. The Preferred CEPP is a catalyst for qualitative benefits because it can enable certain actions from the Company that should be integral to the Commission's evaluation of the proposal.

For over 40 years, Pueblo has acted as a host for Comanche 1 (commercial operation in 1973) and Comanche 2 (commercial operation in 1975). We value that partnership and we place significant value on a plan — like the Preferred CEPP — that reinforces our commitment to a long-time host community — like Pueblo — by providing construction jobs, property taxes, and solidifying a continued presence in Southern Colorado.

[7] For counties with only single projects the total investment is provided as Highly Confidential information.
[8] The two wind projects in this area of Colorado cover territory in both Kit Carson and Cheyenne counties; therefore, these counties are grouped together.
[9] The best value employment metrics provided by bidders in Appendix M also show some of the benefits associated with these projects.
[10] Decision No. C18-0191, at ¶ 27 (mailed Mar. 22, 2018) ("The Phase II process is designed to consider both quantitative (*i.e.,* modeled NPVRR cost comparisons between portfolios) and qualitative factors such as jobs or certain environmental factors.")

These local benefits are realized in several ways. First, the development of substantial amounts of solar and battery storage and other supporting infrastructure in the Pueblo area has a beneficial property tax impact that more than offsets for the loss of property tax income from the early retirement of Comanche 1 and Comanche 2. Stated simply, under the Preferred CEPP, local taxing authorities are projected to receive *more* revenue than they do today with Comanche 1 and Comanche 2 operating in Southern Colorado.

Table 5 - Preferred CEPP Impacts on Pueblo Taxing Authorities[11]

	Pueblo County	School District 60	Library District
Tax Without Units 1 and 2	$6,599,340	$7,325,783	$1,129,287
Loss From Units 1 and 2 Retirement	$(252,264)	$(280,032)	$(43,168)
Additional Tax From Switching Station(s)	$204,093	$234,012	$34,925
Additional Tax from 525 MW Solar + 225 MW Storage	$1,385,928	$1,589,101	$237,162
Tax position after retirements with Switching Station(s) 525 MW Solar + 225 MW Storage	***$7,985,268***	***$9,148,896***	***$1,401,374***

Second, the Company and Pueblo County have reached agreement regarding an amendment to an existing Property Tax Incentive Agreement. This agreement is conditioned on the approval of the Company's Preferred CEPP in this proceeding and would help further Pueblo County's economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program."

Third, approval of the Preferred CEPP and the investments for the Company included as part of this plan puts Public Service in a position to be able to move forward with its EVRAZ contract. EVRAZ employs approximately 1,000 people in Pueblo and is the largest customer on the Public Service system but has expressed its intention to move its facilities out of Colorado. Assuming Public Service and EVRAZ can reach agreement on terms, the contract enabled by the Preferred CEPP would result in the installation of an on-site 200 to 240 MW solar facility that can help EVRAZ to stabilize its energy costs — a key component of keeping EVRAZ in Pueblo. The State of Colorado and local economic development authorities are similarly motivated to keep EVRAZ in Colorado and have stepped up to provide incentives to retain EVRAZ. The contract enabled by the Preferred CEPP is Public Service's contribution to the team approach to retain EVRAZ, reflecting its importance as a matter of statewide concern. As discussed

[11] This assumes that battery storage is treated as renewable energy property for property tax purposes. If it is treated as non-renewable energy property, then there are additional revenues beyond those reflected in the table to each taxing authority. These estimates are therefore conservative.

above, the contract and net metered on-site solar facility, combined with other incentives provided to EVRAZ by state and local government authorities, create favorable conditions for substantial investments in new production facilities at the EVRAZ steel mill in Pueblo as well as on-site solar, which will increase the overall economic impact of our plan. This effort represents an unprecedented attempt by the Company to retain a large customer whose presence in Pueblo either directly or indirectly impacts the economic welfare of so many in the community. The Company and EVRAZ have structured the contract in a manner that can be (1) cost-justified to the Commission and our other customers and (2) economically justified to EVRAZ and the Company's investors, recognizing the investment opportunity represented by the Preferred CEPP. Moreover, retaining EVRAZ ultimately benefits all Public Service customers as remaining customers avoid cost increases associated with the departure of the largest customer on the Public Service system.

If the Preferred CEPP is approved, the Company will also carry out a workforce management plan for Comanche 1 and Comanche 2. As the Commission knows from this and prior proceedings, the Company has deep experience with developing and implementing successful, low impact workforce transition plans. With Cameo, Arapahoe, Valmont, and Cherokee retirements in Colorado, we did not implement an official layoff or forced workforce reduction. We intend to achieve the same result here for Comanche employees.

<u>The Cost-Effectiveness Standard</u>

There are many reasons, outlined above and throughout this 120-Day Report, that the Commission *should* approve the Preferred CEPP. It provides customer savings, environmental benefits, clean energy benefits, diversity and system operation benefits, economic development benefits, and host community benefits. Here we note the Commission *can*, consistent with Colorado law, approve the Preferred CEPP. The State of Colorado prioritizes economics and environment in its energy mix and employs a cost-effectiveness standard in resource planning. The Preferred CEPP is a cost-effective resource plan.

Rule 3601 embodies the Commission's shift from least-cost planning to cost-effective planning in response to legislative directives from the General Assembly in 2006 and 2007. The Commission explained "our new ERP Rules establish a framework for the Commission to approve a plan for resource acquisition in Phase I, similar to the previous LCP Rules, but adds a Phase II process wherein the Commission weighs the various risks and benefits of proposed resources to establish a preferred resource portfolio." Rule 3601 defines the purpose and goals of an ERP, which include minimizing the present value of revenue requirements while giving "the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies." The Commission reinforced the scope of the cost-effectiveness evaluation used in the ERP process in its order allowing the Preferred CEPP to be brought forward, providing that "[t]he Phase II process is designed to consider both quantitative (i.e., modeled NPVRR cost comparison between portfolios) and qualitative factors such as jobs or certain environmental benefits."

Cost-effectiveness, as opposed to least-cost, therefore guides the Company's development of its preferred portfolio in this proceeding. To assist in the evaluation of the cost-effectiveness of the Preferred CEPP under Rule 3601, the Commission ordered the Company to develop other portfolios and run numerous sensitivities to further the evaluation. These additional portfolios are included throughout this 120-Day Report, but the table below provides comparisons across select portfolios and key metrics.

Table 6 - Preferred CEPP and Select Other Portfolios

Portfolio ID		3	6	5	10
Portfolio Name		**Preferred ERP**	**Preferred CEPP**	**CEP LCP**	**CEP 775 500 Owned**
Comanche 1 & 2 Retire Year		2033/2035	2022/2025	2022/2025	2022/2035
RAP Resource Need (MW)		450	775	775	775
Targeted Resource Acquisition (MW)		450	1,110	1,110	775
Portfolio Generation	(1)				
Wind (MW)		789	1,131	830	1,131
Solar (MW)		322	707	982	457
Battery Storage (MW)		50	275	275	150
Gas (MW)		301	383	448	383
Portfolio Firm Capacity (MW)	(2)	554	993	1,143	780
Total Generation Investment ($M)	(3)	$1,460	$2,550	$2,300	$2,220
Company Ownership (% of Nameplate)	(4)				
Eligible Energy Resources (%)		0%	27%	0%	31%
Dispatchable/Semi-Dispatchable (%)		86%	58%	42%	72%
Portfolio Transmission	(5)				
Badger Hills Switching Station ($M)		$0	$12	$0	$12
Pueblo Area Reliability ($M)		$0	$10	$10	$10
Transmission Upgrades ($M)		$132	$100	$100	$132
Total Transmission Investment ($M)		$175	$204	$201	$221
2016 – 2054 Planning Period PVRR ($M)	(6)	$34,901	$34,687	$34,573	$34,794
PVRR Savings vs. Preferred ERP ($M)		**-**	**$213**	**$328**	**$106**
PVRR Costs vs. CEP LCP ($M)		$328	$114	-	$222
Total Investment ($M)		$1,636	$2,754	$2,499	$2,439
2026 CO_2 Reduction (%)	(7)	47%	59%	58%	54%

Notes:

(1) MW Nameplate by Technology
(2) MW of firm capacity added within the Resource Acquisition Period (RAP)
(3) Total portfolio generation investment is estimated based on industry averages of costs by size and technology type of the resource types within each portfolio. Estimates are rounded to the nearest $10M.
(4) % of Portfolio nameplate generation owned by PSCo for Eligible Energy (as defined by CO Rev Stat § 40-2-124 (2016)) and Dispatchable/Semi-Dispatchable resources (as defined in Section 1.3 of the Dispatchable and Semi-Dispatchable RFPs)
(5) Total Transmission related capital costs (interconnection and delivery)
(6) Present Value of Revenue Requirements, discounted at 6.78%
(7) Year 2026 CO_2 percent reduction from 2005 levels

As in the last ERP process, the least-cost resource portfolio in this ERP is not the preferred portfolio for either the ERP 450 MW case or the CEPP - as the qualitative benefits substantively outweigh the incremental cost. As noted above, the Company's Preferred CEPP is cost-effective. On a quantitative level, it utilizes diverse and low-cost renewable and battery storage projects to drive hundreds of millions in savings for customers as compared to a future where Comanche 1 and Comanche 2 each remain online for an additional decade. It satisfies the cost test of providing savings on a present value basis as compared to the Preferred ERP to the tune of over $200 million.

The Preferred CEPP is more expensive than the CEP LCP, in this instance by $114 million on an NPV basis. The $114 million difference between the CEP LCP and the Preferred CEPP is based on reasonable assumptions and modeling. However, they are also conservative. This 120-Day Report lays out two additional approaches that, if adopted, will provide additional savings to the Preferred CEPP and, in turn, bring the two portfolios closer together in cost. First, the DTA associated with Company-owned wind for unused PTCs and its revenue requirement comprise $82 million of the $114 million difference between the CEP LCP and the Preferred CEPP. As outlined in Section 4, the Company has taken steps to mitigate DTA impacts, and is also evaluating the alternative approach to the treatment of unused PTCs that could result in approximately $20 million in customer savings. Second, as discussed later in this section, the Company estimates that pursuing the Alternative CEPP as opposed to the Preferred CEPP and deferring filling the Comanche 2 resource need to the next ERP could yield an additional $20 million in savings over and above the savings of the Preferred CEPP. This potential for additional savings illustrates that the $114 million difference between the CEP LCP and Preferred CEPP, while reasonable, is conservative and a boundary analysis for the Commission to evaluate the cost-effectiveness of the Preferred CEPP (or the Alternative CEPP if that path is preferable to the Commission).

Equally as important, the CEP LCP — a portfolio provided as a comparative benchmark — does not confer the benefits delivered by the Preferred CEPP. In particular, the Preferred CEPP delivers significant value in three important ways. First, the Preferred CEPP and the associated renewable ownership financially positions the Company to move forward with the EVRAZ contract and amendment to the Property Tax Incentive Agreement in Pueblo. Second, the Preferred CEPP keeps an anchor employer in Pueblo while simultaneously plotting a new energy and economic future for that community. Third, it encourages companies in Colorado to come forward with innovative ways to transform their environmental performance. In that way, the Commission could acknowledge (as it has before) the voluntary nature of the Comanche 1 and Comanche 2 early retirements and the significant concessions made by Public Service in order to develop and advance the Colorado Energy Plan.[12] For these and many other reasons, the Preferred CEPP represents a unique and transformative opportunity that will set Colorado on a course that will benefit Public Service customers, local communities, and the State of Colorado as a whole.

[12] Decision No. C18-0191, at ¶ 50 ("[W]e recognize the particular importance of utility ownership in the voluntary proposal to retire Comanche 1 and 2, which includes other concessions from Public Service such as restricted utility-builds, deferral of utility construction under Rule 4 CCR 723-3-3660(h), a requirement for cost neutrality or savings of the CEP Portfolio, and the presenting of the CEP Portfolio within an ERP proceeding.")

2.2 Alternative Colorado Energy Plan Portfolio

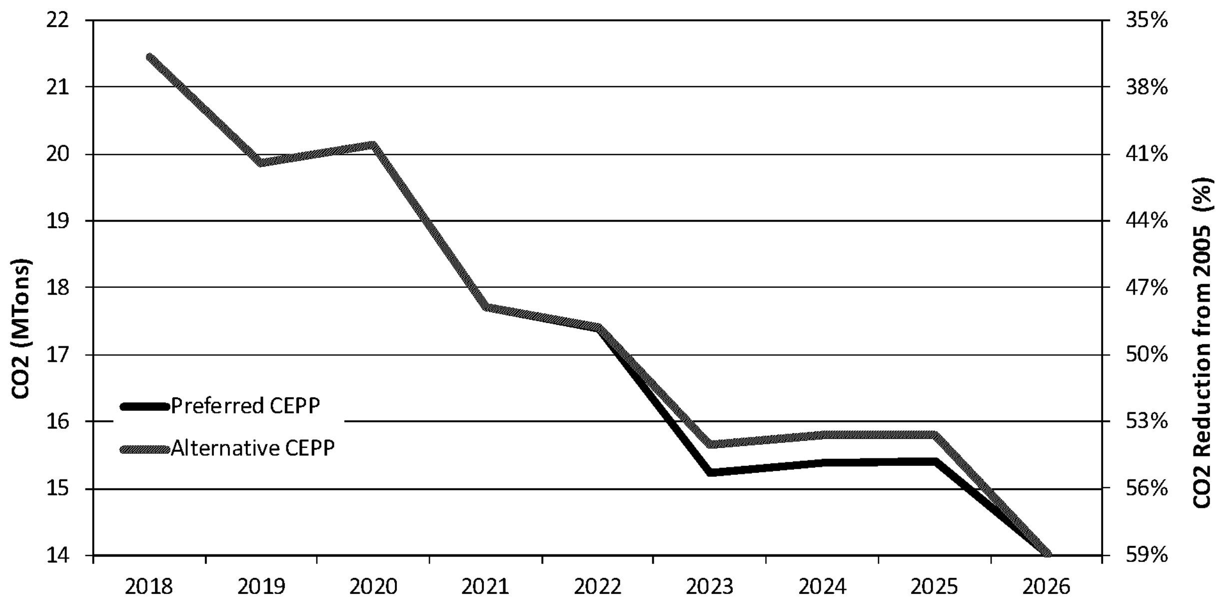
The Alternative CEPP is also an opportunity for this Commission to continue the transition of the Public Service generation fleet, bolster economic development across Colorado and lower customer bills. As discussed above, this portfolio offers a moderately different path for the Commission if it prefers to defer the resource acquisition opportunities created by the retirement of Comanche 2 to the next ERP cycle. This approach notably provides many of the same benefits as the Preferred CEPP and therefore the Company believes this represents a slightly modified plan that is still a cost-effective resource plan, which - as discussed above is - the goal of the ERP Rules. This slightly different CEPP would result in the addition of 1,131 MW of wind, 457 MW of solar, 150 MW of storage (again embedded in solar plus battery storage projects), and 383 MW of existing gas resources in this ERP. In sum, it results in the acquisition of 250 MW less solar and 125 MW less battery storage in this ERP cycle as compared to the Preferred CEPP.

The Company is receptive to this approach if the Commission believes it represents a more measured and appropriate path for customers. The Company has selected a solar with storage project to eliminate in the Alternative CEPP. This modification is appropriate given that solar projects can still benefit from the full ITC into the next ERP cycle. Deferring new construction as opposed to selecting an existing project to defer avoids stranding an existing asset and, by selecting a project located in Southern Colorado to defer, it defers a project from an area that will still see substantial renewable development through the Alternative CEPP. In doing so, the Alternative CEPP also maintains geographic and supplier diversity in its generation mix. The plan still would bring on substantial amounts of solar and storage, with 457 MW of solar coming online during the RAP and an additional 150 MW of battery storage embedded in solar projects. From a firm capacity standpoint, the Alternative CEPP would fill the entirety of the 450 MW resource need and Comanche 1 replacement capacity, while deferring the Comanche 2 replacement capacity to the next ERP.

The Alternative CEPP was assembled based on the full suite of information developed as a result of the Commission decisions addressing both Phase I of this proceeding and the Stipulation that outlines the framework for the CEPP. The Company decided to bring the Alternative CEPP forward given the magnitude of resource acquisitions contemplated in the Preferred CEPP, which would result in the acquisition of nearly 2.5 GW of new generation resources based on nameplate capacity. First and foremost, this portfolio would still result in the voluntary early retirement of Comanche 1 no later than the end of 2022 and Comanche 2 no later than the end of 2025, consistent with the Stipulation. This has not changed and the Company remains committed to the voluntary retirement of both units if either the Preferred CEPP, or this variation on it, is approved by the Commission.

In fact, the Alternative CEPP bears far more similarities to the Preferred CEPP than differences. The voluntary early retirements are the same under this plan and this plan would still achieve customer savings, clean energy benefits, environmental benefits, geographic diversity and system operation benefits, economic development benefits, and host community benefits. For example, the Company's energy mix in 2023 would feature approximately 51% renewable energy in 2023 with the Alternative CEPP and 53% renewable energy by 2026. Further, if this plan were chosen by the Commission in lieu of the Preferred CEPP, emissions reductions would still be achieved through the early retirement of the coal-fired generation, with approximately 60% reduction in CO_2 emissions by 2026 (from 2005 levels), as reflected below.

Figure 6 - Preferred CEPP / Alternative CEPP CO_2 Emissions



Given the geographic diversity of the resource in the portfolio, it would also allow for the development of and investment in communities in different regions of Colorado. In addition, approval of this portfolio would still put the Company in a position to move forward with the EVRAZ contract and amendment to the Property Tax Incentive Agreement in Pueblo. Accordingly, it would still retain EVRAZ in Pueblo and free up funds for Pueblo County to use on economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program." These host community benefits do not change with this portfolio.

The only difference between this approach and the Preferred CEPP lies in the procurement of new and existing generation resources to fill the resource need inclusive of the retirements of Comanche 1 and Comanche 2. While it would result in the acquisition of less solar and battery storage in Southern Colorado, Pueblo County would still see 275 MW of solar and 100 MW of storage developed in the county with corresponding economic benefits. To the extent the Commission prefers this approach, it could achieve additional savings in the future by better aligning the timing for acquiring the last tranche of resources to fill the need created by the early retirement of Comanche 2 with the timing of the actual retirement of Comanche 2 at the end of 2025. By aligning new low-cost solar resources and storage (or any other low-cost resources available at that time) with the Comanche 2 retirement date in the next ERP we anticipate that we could achieve approximately $20 million in additional savings on a present value basis – above and beyond the savings of the Preferred CEPP as compared to the Preferred ERP. This assumes that these resources see no decline in price and is, in that way, a conservative assumption given that we anticipate solar and storage will continue to be available at low, if not lower, prices in the next ERP cycle, and the next ERP will still be timed to take advantage of the full 30% ITC. Moreover, the Alternative CEPP would maximize the acquisition of 100% PTC wind and stay at the 1,131 MW level in the Preferred CEPP. Capitalizing on this low-cost wind now is a feature of both the Preferred CEPP and this portfolio. As the PTC is already beginning to step down to lower amounts, we believe moderating the solar and associated storage is the most appropriate moderation path for this smaller portfolio.

This portfolio offers a slightly different path than the Preferred CEPP but is progressive and transformative in its own right. It simply fills the resource need from Comanche 1 and Comanche 2 across both this ERP and the next ERP as opposed to filling all of the resource need in this ERP. And it does so while still taking advantage of low-cost renewable and battery storage resources available now for customers. In addition, assuming the continued availability of low-cost solar and storage into the next ERP – a reasonable assumption in our estimation – the Alternative CEPP creates an opportunity for additional savings above and beyond that of the Preferred CEPP by deferring resource acquisitions into our next ERP cycle.

2.3 Preferred ERP Portfolio

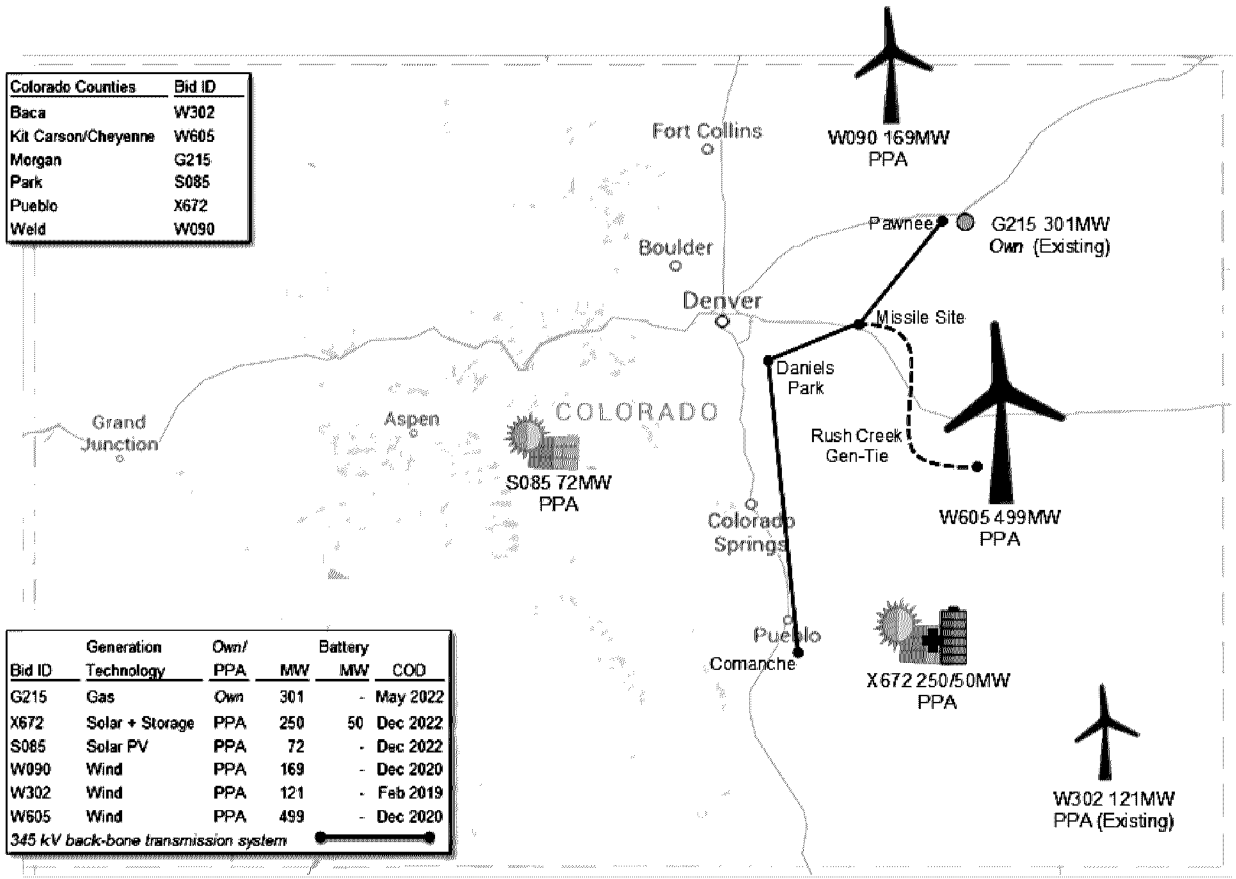
The Company's Preferred ERP is identified consistent with the Commission's Phase I Decision (Decision No. C17-0316, "Phase I Decision"). While the Preferred ERP Portfolio fills the 450 MW resource need, it looks very different than the Preferred CEPP in that Comanche 1 and Comanche 2 remain online until 2033 and 2035, respectively. And although the Preferred ERP Portfolio still results in the addition of renewable resources, some storage, and acquisition of existing gas generators, it does not deliver the same level of emissions reduction benefits, customer savings, and economic development benefits of either the Preferred CEPP or the Alternative CEPP.

That said, the Preferred ERP would represent a step forward for the Public Service generation fleet by providing an incremental shift in the Company's generation fleet toward a cleaner energy future, although at a greater cost to customers. With respect to resource additions, the Preferred ERP would add 789 MW of wind, 322 MW of solar, 50 MW of storage, and 301 MW of gas. As with the Preferred CEPP, the Preferred ERP is not the least-cost portfolio to fill the 450 MW need. The primary difference between the Preferred ERP and the least-cost ERP portfolio is that the Preferred ERP takes less battery storage and instead acquires an existing gas generator. This results in a Preferred ERP that is $14 million more expensive on a present value basis than the least-cost ERP portfolio over the Planning Period. Notwithstanding the relatively small cost differential, the Company identified the Preferred ERP as preferable to the least-cost ERP portfolio for several reasons, including the reliability benefits of acquiring existing gas at a very favorable price for customers. Additionally, the Preferred ERP is a cost-effective resource plan if the Commission determines it is not appropriate to move forward with the early retirement of Comanche 1 and Comanche 2 at this time.

A comparison between the Preferred ERP and the Preferred CEPP makes clear the basis for the Company's decision to advance the Preferred CEPP as the recommended path. The Preferred ERP is $213 million more expensive for customers on a present value basis than the Preferred CEPP. In addition, this portfolio does not achieve the CO_2, SO_2, and NO_X emission reductions of the Preferred CEPP because Comanche 1 and Comanche 2 would remain on the system for an additional decade. Moreover, because Comanche 1 and Comanche 2 remain online until their terminal retirement dates of 2033 and 2035, there are more limited opportunities for new low-cost renewable generation to come onto the system with the Preferred ERP.

Turning to diversity benefits, the Preferred ERP delivers some geographical diversity as reflected in the map below, but it falls short of delivering the balance of ownership that this Commission has rightly identified as an important customer protection. Specifically, the Preferred ERP would result in IPP ownership of 1,111 MW of renewable resources through PPAs (100% of all renewables in the Preferred ERP) and utility ownership of 301 MW of dispatchable and semi-dispatchable resources (86% of all dispatchable and semi-dispatchable resources in the Preferred ERP). This is inconsistent with past Commission statements regarding the importance of balanced ownership, which were reaffirmed in this proceeding in Decision No. C18-0191.

Figure 7 - Preferred ERP Generation Locations



Colorado Counties	Bid ID
Baca	W302
Kit Carson/Cheyenne	W605
Morgan	G215
Park	S085
Pueblo	X672
Weld	W090

Bid ID	Generation Technology	Own/ PPA	MW	Battery MW	COD
G215	Gas	Own	301	-	May 2022
X672	Solar + Storage	PPA	250	50	Dec 2022
S085	Solar PV	PPA	72	-	Dec 2022
W090	Wind	PPA	169	-	Dec 2020
W302	Wind	PPA	121	-	Feb 2019
W605	Wind	PPA	499	-	Dec 2020

In addition to diminished wind, solar and storage acquisitions generally, the Preferred ERP does not deliver the level of host community benefits of either the Preferred CEPP or the Alternative CEPP. For instance, the Preferred ERP does not enable the EVRAZ contract from an economic perspective. The Company would obtain very low levels of new investment from the Preferred ERP, which in turn makes it difficult to take on the shareholder risk that is necessary to enable the EVRAZ contract. Further, because Comanche 1 and Comanche 2 remain online under the Preferred ERP, the amendment to the Pueblo County Tax Incentive Agreement would also fall away.[13] And while Pueblo County would retain the property tax revenues tied to Comanche 1 and Comanche 2, the local government would not obtain the benefits of the amendment, which is designed to help further Pueblo County's economic development and community improvement objectives through the Pueblo County "1A Community Improvement Program." For all of these reasons, the Pueblo area and Southern Colorado generally stand to benefit less from the Preferred ERP as compared to the Preferred CEPP or Alternative CEPP.

[13] Approval of the Preferred CEPP or Alternative CEPP is a condition precedent to the amendment of the Pueblo County Tax Incentive Agreement. The amendment is premised on Comanche 1 and Comanche 2 retiring early and leaving only Comanche 3 in the Pueblo County tax base at the Comanche site.

If the Commission determines the early retirement of Comanche 1 and Comanche 2 is not appropriate or in the public interest, then the Company believes the Preferred ERP represents a cost-effective resource plan under the circumstances and should be approved by the Commission. When taking a broader view and comparing the Preferred ERP to the Preferred CEPP in a world where Comanche 1 and Comanche 2 retire early, the strength of the Preferred CEPP becomes apparent from all sides – namely, lower costs to customers and improved environmental benefits, diversity benefits, economic development benefits, and benefits to Pueblo and Southern Colorado. The Preferred CEPP saves customers money while delivering significantly more and varied benefits to a diverse set of stakeholders across the state.

3.0 Independent Evaluator Coordination

The Company has worked in close coordination with the Independent Evaluator ("IE") throughout the bid solicitation, bid receipt, and bid evaluation process to ensure the process was fair and in full alignment with conditions set out by the Commission. As described below, the Company consulted with the IE throughout the Phase II process consistent with ERP Rules and Commission decisions.

3.1 Role of the Independent Evaluator

In its Phase I Decision, the Commission determined that an IE was necessary for Phase II of this ERP "for the limited purposes of fulfilling certain roles contemplated under Rule 4 CCR 723-3-3613." Paragraph 176 of the Phase I Decision requires the IE to perform the following tasks:

> The IE shall provide a report to the Commission, pursuant to paragraph 3613(e) of the ERP Rules, containing an analysis of whether Public Service conducted a fair bid solicitation and bid evaluation process, with any deficiencies specified in the report.
>
> The IE shall include in the report how Public Service implemented the Commission's Phase I decision in the bid evaluation process. The IE shall independently review the inputs and outputs from the bid evaluation modeling, including in the report an assessment as to whether the resulting outputs are feasible, and alerting the Commission and parties through the report where there may be deficiencies in the outputs. The IE will not provide opinions regarding whether the public interest may be served through the acquisition of any particular resource. Also, the IE will not make any findings of fact or render legal conclusions, as those duties rest solely with the Commission.
>
> The IE shall also provide a log of contacts with the utility and other parties pursuant to paragraph 3612(d) of the ERP Rules.

The Commission further directed that the IE should be engaged before the release of the All-Source Solicitation Request for Proposals ("RFPs") and directed Public Service to provide the IE with full copies of each bid received and all information used in the bid evaluation process.

At the Phase I evidentiary hearing on February 6, 2017, the Company reported that the Company, Staff, and the Colorado Office of Consumer Counsel ("OCC") had conferred and agreed on an IE, Accion Group, LLC ("Accion"). The Commission subsequently approved Accion as the IE for Phase II of the proceeding and approved the contract between Accion and Public Service for IE services, pursuant to Rule 3612(b) (Decision No. C17-0494, mailed June 15, 2017).

In Paragraph 125 of the Commission's decision granting approval for the Company to present a Colorado Energy Plan Portfolio in Phase II (Decision No. C18-0191, the Commission required the IE to "assess the reasonableness of the modeling of the baseline and CEP Portfolios, and the resulting cost-effectiveness of the proposed early retirement of Comanche 1 and 2, consistent with the Phase I Decision and [Decision No. C18-0191]." The Company discussed this requirement with the IE and this assessment will be addressed in the IE's Report in addition to the requirements set forth in the Commission's Phase I Decision.

As required by Rule 3613(e), the IE will file a report with the Commission no later than 30 days after the filing of this 120-Day Report that includes its assessment and conclusions regarding the Company's bid solicitation and evaluation process, with any deficiencies specifically reported.

3.2 Summary of Independent Evaluator Coordination

Pre-RFP Issuance

Prior to issuing the 2017 All-Source Solicitation RFPs on August 30, 2017, the Company provided the IE with drafts of each of the RFP documents before their release, and a final copy of each, consistent with Volume III of the ERP as approved in the Phase I Decision.

Separation Protocol

Additionally, prior to issuing the 2017 All-Source Solicitation, the Company issued an internal Separation Protocol that went into effect with the issuance of the RFPs. The Separation Protocol divided Company personnel into three teams: (1) the Bid Evaluation Team, (2) the Company Self-Build Team, and (3) Specialized Technical Support Personnel. The protocol was designed to manage communications with bidders and avoid any improper communications with, between, or among members of the Company Self-Build Team and/or the Bid Evaluation Team. All impacted personnel were required to sign an acknowledgement stating they had read the Separation Protocol and agreed to abide by it. The Separation Protocol was reviewed with the IE prior to implementation.

Bidder Communications Protocol

The Company established a dedicated email address through which all communications between bidders and the Company occurred. The Company took this step in order to ensure that all bidders were similarly situated in how they sent and received information related to the RFP. Importantly, the IE had full access and visibility into all emails sent to or from the dedicated email address.

Pre-Bid Conference

On September 28, 2017, the IE participated in the Pre-Bid conference held at the Company's Denver offices and via webinar. The purpose of the Pre-Bid conference was to provide an overview of the solicitation process and allow potential bidders to ask questions and seek additional information about the Phase II process. During the Pre-Bid conference, the IE provided an overview of Accion's experience, its role as the IE in this process, and Accion's objective of keeping the bid evaluation process fair for all bidders. A copy of the IE's presentation and an audio recording of the presentation was posted to the 2017 All-Source Solicitation website located at this link:

https://www.xcelenergy.com/psco2017allsource

Model Lock-Down

The IE utilized a model "lock down" process to ensure the models used to evaluate bids and select portfolios were fair, unbiased and consistent with the approved Phase I assumptions. Prior to bid receipt, the Resource Planning Analytics group provided to the IE a "locked-down model," consisting of all of the various inputs to Strategist, a number of mock bids of varying resource types, and all of the outputs associated with running the Strategist model with those mock bids. The IE consulted on the design of these mock bids before they were run in Strategist and reviewed the model outputs with the Company for reasonableness.

The purpose of this process is to demonstrate the portfolio analysis tools remained unchanged throughout the bid evaluation process - the same mock bids are re-run in Strategist at the end of the process and the model outputs are compared to ensure no changes were made.

However, during the bid evaluation process, the model sometimes needed to be "re-locked" when changes or updates to the model needed to be made either to correct errors or to implement changed modeling processes. This un-locking and re-locking of the model is a normal part of the process[14] and each change was monitored by the IE. Moreover, prior to any adjustments, the change and the rationale for the change were discussed with the IE and the IE made the final determination on whether the change was valid and necessary. After the agreed upon change was made, the IE was provided a new version of the locked-down model and mock bid outputs incorporating the change.

[14] As an example, the original locked down model is done prior to bid receipt. Per the Phase I order, the costs of the "replacement CT" used to backfill bids in the replacement method are reset to match the lowest cost Company self-build CT proposal. To accomplish this in the model, a routine "re-lock" is necessary.

Bid Receipt

On November 29, 2017, the IE was present at the Company's Denver offices to oversee the Company taking possession of all bid packages received by the November 28, 2017 bid receipt deadline. The IE personally opened all bids from the Company self-build team. The IE remained on-site during the entire bid opening process, observing firsthand and working closely with the Bid Evaluation Team during the opening and logging of all bids received. The IE was provided with a hard copy and an electronic copy of all bids received.

Information Access and Procedures

The Company maintained a SharePoint site for the purposes of bid evaluation and disseminating information internally with Subject Matter Experts. The IE was granted full access to all materials pertaining to the bids and the Company's evaluation of those bids, including unrestricted access to the Company's internal 2017 All-Source SharePoint site and all supplemental data the Company requested from bidders during the bid review process.

Bid Affirmation and Refresh Process

On January 12, 2018, Public Service made a filing with the Commission that addressed the Company's need to implement a bid affirmation and refresh process that would require all bidders to either affirm or refresh bid prices based on the passage and signing into law of new federal tax legislation, the Tax Cuts and Jobs Act ("TCJA"), and a final decision from President Trump in the Suniva/SolarWorld trade case regarding solar equipment tariffs. By Decision No. C18-0051-I (mailed January 19, 2018), the Commission granted the Company's request for a partial waiver of Rule 3613(a) to accommodate the bid affirmation and refresh process. The bid affirmation and refresh process was closely coordinated with the IE prior to and following its implementation. Further details of the bid affirmation and refresh process are found in Section 6.0.

Bid Advancement to Computer-Based Modeling

Prior to advancing bids to computer-based modeling, the Company discussed with the IE the proposed criteria for bid advancement and how the Company intended to conduct the 45-day notifications pursuant to Rule 3613(a). The Company reviewed with the IE each bid it proposed to move forward to computer modeling, and received concurrence from the IE regarding the bid advancement determination and the bidder notification process. Similarly, the Company notified the IE of each bid that was not advancing to the computer-based modeling stage of the Phase II process.

Request to Renewable BOT Bidders to Identify Financing Related Costs

On April 6, 2018, following coordination and discussion with the IE, Public Service requested that developers who had proposed competitive wind and solar build-own transfer ("BOT") proposals provide construction payment-related information (i.e., engineering, procurement, and construction costs and other project payments) for their proposals based on the assumption that Public Service would provide financing for construction. This request was intended to explore whether additional customer cost savings could be realized as a result of Public Service financing the construction of renewable BOT projects in lieu of the developer financing these costs. Through this exercise it was determined that, for this set of projects, there were not material cost savings to customers as a result of having Public Service finance the construction. As a result, the pricing information provided in response to this request was not used in the evaluation of BOT bids. In its consultation with the IE, the IE agreed with the Company regarding the process and purpose of this additional information request.

Portfolio Selection and Results Review

The Company worked with the IE in the initial stages of the modeling process to jointly develop a methodology to evaluate bids and select portfolios and together created a modeling process "map" to document the process. This initial map was adhered to throughout the modeling phase. Periodically during the modeling process, including at each discrete step discussed in Section 6.0, the Company shared interim results with the IE and discussed current findings and conclusions. Extensive modeling data was delivered to the IE via electronic media so the IE could review and comment on the same data the Company was evaluating.

Following final completion of the computer modeling and selection of the portfolios presented in this report, the Company met with the IE, first via conference call and later in-person, to discuss the results and explain the rationale and methodology in the selection of the preferred ERP and CEPP portfolios. All modeling data and results were forwarded to the IE for inspection and validation

Ongoing Coordination Meetings

In addition to the key coordination described above, the IE regularly met with the Company's Resource Planning Analytics group to discuss modeling procedures and interim results and, separately, with the Company's Transmission Access group to discuss the interconnection and delivery requirements and costs of individual bids and bid combinations. These regular updates provided an opportunity for the Company to keep the IE updated throughout the process. As discussed in the modeling process narrative (Section 6.0), the IE provided valuable insight and suggestions that were utilized in the process to identify the top bids and sequentially re-focus the analysis to smaller subsets of optimal portfolios.

4.0 Analysis of Preferred Portfolios

Section 4.0 provides an overview of the suite of bid portfolios developed to comply with the Commission directives in the Phase I Decision and Decision No. C18-0191. This section has four discrete parts. First, it provides an overview of the eleven bid portfolios developed to meet differing levels of capacity need and satisfy Commission directives issued over the course of this ERP proceeding. Second, it focuses in on the Preferred ERP and Preferred CEPP, building on the discussion in Section 2.0 regarding these two portfolios and provides a more detailed comparison of key aspects of the Preferred ERP and Preferred CEPP, including a comparative analysis of generation mix, costs, ownership, and the level of firm capacity. Third, it addresses tax impacts associated with portfolio development, including the TCJA and DTA impacts for utility-owned wind projects. Fourth, and finally, Section 4.0 discusses the generation interconnection queue, explains the process for estimating potential transmission upgrades and describes how selected projects may advance through the interconnection queue.

4.1 General Overview of Portfolios

The Strategist model was used to construct a variety of bid portfolios that meet two distinct levels of RAP capacity need ordered for the ERP proceeding (0 MW and 450 MW). In addition, the model was used to develop bid portfolios involving aspects of the CEP that consider the early retirement of Comanche 1 and Comanche 2 and replacing the capacity of either one or two units within this ERP (775 MW and 1,110 MW).[15] The early retirement of the 325 MW Comanche 1 in 2022 increases the RAP capacity need for the CEP to 775 MW.[16] Consistent with Commission directives in this proceeding, eleven individual portfolios, summarized in Table 7 below, are presented for Commission evaluation in this 120-Day Report.

In Section 4.1.1, we begin by summarizing each portfolio and then in Section 4.1.2 discuss the results of applying the annuity method for backfilling bids versus the replacement method. Following that, we provide a comparative analysis of preferred portfolios and a discussion of the required sensitivity analyses that were applied to the portfolios.

[15] A portfolio that replaces the capacity of both Comanche 1 and Comanche 2 would include a total of 1,110 MW of firm capacity within the RAP which is 335 MW more than is needed to fill the RAP resource needs in this ERP.
[16] ERP need 450 MW + 325 MW = 775 MW CEP capacity need.

Table 7 - Bid Portfolio Analysis Summary Results (Replacement Method)

		ERP 0 MW Portfolio	ERP 450 MW Portfolios (Com 1 & 2 Continue Operation)			CEP 1110 MW Portfolios (Early Retire Com 1 & 2)				CEP 775 MW Portfolios (Early Retire Com 1)		
Portfolio #		1	2	3	4	5	6	7	8	9	10	11
Portfolio Name		LCP	LCP	Preferred	All Thermal	LCP	Preferred	Full Replacement	MLEP	LCP	500 Owned	MLEP
Nameplate Capacity (MW)	Notes:											
Solar		0	432	322	0	982	707	707	907	782	457	582
Wind		789	789	789	0	830	1131	1131	930	830	1131	889
Storage		0	175	50	0	275	275	275	225	175	150	200
Gas		0	82	301	583	448	383	530	501	301	383	383
Total Nameplate MW		789	1478	1462	583	2535	2496	2643	2563	2088	2121	2054
Owned EER MW	1	0	0	0	0	0	500	500	761	0	500	599
Owned D/SD MW	2	0	82	301	583	301	383	383	501	301	383	383
Owned EER %	3	0%	0%	0%	0%	0%	27%	27%	41%	0%	31%	41%
Owned D/SD %	4	0%	32%	86%	100%	42%	58%	48%	69%	63%	72%	66%
RAP Firm Capacity (MW)												
Total Firm Capacity	5	79	503	554	534	1143	993	1125	1137	856	780	859
Excess of 2023 Need	6	(375)	49	100	80	363	213	346	358	76	0	80
2023 Reserve Margin %	7	11.0%	17.0%	17.7%	17.4%	21.5%	19.3%	21.2%	21.4%	17.4%	16.3%	17.4%
Planning Period PVRR ($M)												
Base Portfolio	8	$34,709	$34,672	$34,691	$35,399	$34,339	$34,345	$34,363	$34,428	$34,352	$34,433	$34,475
Electric Interconnection	9	$14	$47	$42	$4	$97	$73	$73	$91	$83	$57	$58
Electric Delivery	10	$113	$149	$149	$1	$113	$113	$113	$113	$149	$149	$113
LCI and Voltage Control	11	$12	$12	$12	$6	$17	$44	$44	$23	$17	$44	$23
DTA	12	$0	$0	$0	$0	$0	$82	$82	$169	$0	$82	$103
Operating Reserves	13	$7	$7	$7	$0	$7	$30	$30	$13	$7	$30	$13
Total PVRR		$34,854	$34,887	$34,901	$35,410	$34,573	$34,687	$34,704	$34,836	$34,608	$34,794	$34,785
PVRR Delta vs Preferred ERP	14	($47)	($14)	$0	$510	($328)	($213)	($196)	($65)	($293)	($106)	($116)

Table notes:

(1) Nameplate MW of Eligible Energy Resources (EER) to be utility owned
(2) Nameplate MW of Dispatchable and Semi-dispatchable (D/SD) resources to be utility owned
(3) % of Eligible Energy Resources (EER) to be utility owned
(4) % of Dispatchable and Semi-dispatchable (D/SD) resources to be utility owned
(5) Total firm generation capacity added in RAP that serves to meet the resource need
(6) Amount of firm generation capacity within the RAP in excess of that required to meet 16.3 % reserve margin
(7) Level of reserve margin in summer 2023 that will result by adding the projects contained in the portfolio
(8) Baseline Strategist model with individual bids of portfolio added
(9) Costs to interconnect the portfolio projects to the Public Service electric transmission system
(10) Costs to deliver output of portfolio projects from the point of interconnection to customer load
(11) Costs for LCI equipment and equipment to ensure adequate transmission system voltages
(12) Costs associated with the DTA for deferred Production Tax Credits (see Section 4.3 for details)
(13) Costs associated with operating reserves carried to respond to contingency events
(14) Delta in Total PVRR compared to Portfolio 3 (Preferred ERP)

4.1.1 Brief Discussion of Bid Portfolios

The Commission directed the Company to present portfolios beyond the Preferred ERP and Preferred CEPP in this 120-Day Report. For ease of reference, we have included below a summary description of each such portfolio. Additional information as to the specific bids/projects contained within each of these portfolios and the characteristics of those projects can be found in Appendix B.

- Portfolio 1 (ERP 0 MW LCP): This portfolio is comprised of three wind facilities totaling 798 MW. The portfolio has a reserve margin of 11.0%, which is 5.3% lower than the 16.3% reserve margin approved by the Commission. As a result, it represents a Public Service system with a lower level of system reliability when compared against the other ten portfolios in Table 7. Given this difference in system reliability, we concluded that a comparison between the 0 MW LCP portfolio and other portfolios does not provide meaningful results and is therefore not included within the discussion of portfolio comparisons and sensitivity analyses. Moreover, this is not a portfolio the Company can recommend given the potential reliability issues associated with this reduced level of reserve margin.

- Portfolio 2 (ERP 450 MW LCP): This portfolio has the lowest cost PVRR of all 450 MW portfolios.

- Portfolio 3 (Preferred ERP): This portfolio is the Company's Preferred ERP—a detailed discussion of which can be found in Section 2.0 as well as in this section at 4.2.

- Portfolio 4 (All Thermal): This portfolio meets the 450 MW need solely with gas-fired projects. Presentation of this portfolio is intended to provide the Commission a PVRR benchmark for comparative purposes in analyzing the savings of the Preferred ERP against a future that fills the 450 MW ERP need entirely with gas-fired bids.

- Portfolio 5 (CEP LCP): The Commission required presentation of this portfolio by Paragraph 48 of Decision No. C18-0191, where it directed Public Service "to include in the 120-Day Report a least-cost portfolio to meet the 775 MW need and a least-cost portfolio to meet the 1,110 MW need." Consistent with Commission directives, this portfolio includes bids "based solely on the net present value of revenue requirements (PVRR) of the bids" and does "not have ownerships targets." The Commission also held in Paragraph 44 of Decision No. C18-0191 "that the presentation of a least-cost portfolio in Phase II is essential for our analysis of the cost-effectiveness of the CEP Portfolio, and is necessary to determine whether the early retirement of Comanche 1 and 2 is in the public interest." Portfolio 5 is provided for this purpose, i.e., to allow for the evaluation of whether the Preferred CEPP is cost-effective and whether the voluntary early retirement of Comanche 1 and Comanche 2 is in the public interest.

- Portfolio 6 (Preferred CEPP): This portfolio is the Company's Preferred CEPP. It is discussed in Section 2.0 of this 120-Day Report and in more detail later in this section at 4.2.

- Portfolio 7 (CEP Full Replacement): The full replacement portfolio is provided pursuant to Paragraph 47 of Decision No. C18-0191, which required Public Service "to include in the 120-Day Report both a 775 MW need CEP Portfolio (only the Comanche 1 capacity is replaced in this ERP) and an 1,110 MW need CEP Portfolio (capacity for Comanche 1 and 2 replaced in this ERP)." This portfolio deals with the latter scenario. It assumes both Comanche 1 and Comanche 2 are retired early and contains the same projects as the Preferred CEPP; however, it adds one additional gas project, the existing 147 MW Brush 4D unit (Bid ID C172). With the addition of this project, the full replacement portfolio fills the entire 335 MW of Comanche 2. Portfolio 7 results in $196 million in savings compared to the Preferred ERP.

- Portfolio 8 (CEP MLEP):[17] Presentation of this portfolio was required by Paragraph 49 of Decision No. C18-0191, where the Commission found "that the presentation of an MLEP, with reduced ownership percentages, will be useful to our analysis of the overall cost effectiveness of the CEP Portfolio" and therefore directed the Company "to include in the 120-Day Report an MLEP for the 775 MW level of need and an MLEP portfolio for the 1,110 MW level of need." Portfolio 8 represents the least cost combination of ownership projects that fall within the 40% to 60% band of ownership for eligible energy resources and the 60% to 75% band of ownership for dispatchable and semi-dispatchable resources. The MLEP provides higher levels of ownership than the Preferred CEPP given the Company's decision to bring forward a CEPP with ownership levels below the targets for eligible energy resources and dispatchable and semi-dispatchable resources established in the Stipulation. The Stipulation contemplated that a MLEP would need to be $50 million less expensive on a present value basis than the preferred plan. This MLEP does not satisfy this cost metric given that it is $149 million more expensive than the Preferred CEPP on a present value basis. However, it is important to note that the MLEP provides $65 million of savings relative to the Preferred ERP thus meeting the fundamental cost test of the Stipulation. This portfolio also has a considerably higher level of DTA costs. As discussed further below, this portfolio would have been strongly considered to be the Company's preferred plan, however, the decision to mitigate DTA impacts by taking the lower levels of wind ownership ultimately led the Company to the Preferred CEPP. Under Portfolio 8, the Company owns 761 MW of wind resources, representing 41% of the total eligible energy resources.

- Portfolio 9 (CEP 775 LCP): As with Portfolio 5, the Commission required presentation of this portfolio by Paragraph 48 of Decision No. C18-0191 because "the presentation of a least-cost portfolio in Phase II is essential for our analysis of the cost-effectiveness of the CEP Portfolio, and is necessary to determine whether the early retirement of Comanche 1 and 2 is in the public interest." Accordingly, the Company has developed this portfolio to support the Commission's analysis of the cost-effectiveness of the Preferred CEPP. The portfolio assumes the early retirement of Comanche 1 at the end of 2022 and continued operation of Comanche 2 until its terminal retirement date in 2035. The portfolio was developed based solely on the net present value of revenue requirements of the bids absent any ownership targets and fills a resource need of 775 MW.

- Portfolio 10 (CEP 775 500 Owned): As with Portfolio 7, this portfolio is provided pursuant to Paragraph 47 of Decision No. C18-0191, which required Public Service "to include in the 120-Day Report both a 775 MW need CEP Portfolio

[17] Materially Less Expensive Portfolio ("MLEP").

(only the Comanche 1 capacity is replaced in this ERP) and an 1,110 MW need CEP Portfolio (capacity for Comanche 1 and 2 replaced in this ERP)." The portfolio assumes the early retirement of Comanche 1 at the end of 2022 and continued operation of Comanche 2 until its terminal retirement date in 2035. This portfolio provides information as to the costs associated Company ownership of the same 500 MW wind project that is included in the Preferred CEPP.

- Portfolio 11 (CEP 775 MLEP): As with Portfolio 8, presentation of this portfolio was required by Paragraph 49 of Decision No. C18-0191, where the Commission found "that the presentation of an MLEP, with reduced ownership percentages, will be useful to our analysis of the overall cost effectiveness of the CEP Portfolio" and therefore directed the Company "to include in the 120-Day Report an MLEP for the 775 MW level of need and an MLEP portfolio for the 1,110 MW level of need." Similar to Portfolio 8, this MLEP provides higher levels of ownership than the Preferred CEPP given the Company's decision to bring forward a CEPP with ownership levels below the targets for eligible energy resources and dispatchable and semi-dispatchable resources established in the Stipulation. Moreover, the Stipulation contemplated that a MLEP would need to be $50 million less expensive on a present value basis than the preferred plan. This portfolio does not satisfy this cost metric, given that it is $97 million more expensive than the Preferred CEPP on a present value basis. Nevertheless, in compliance with the Commission decision, the Company presents this MLEP.

The Company has provided the best value employment metrics for each resource included in one of the eleven portfolios described in this section. This is provided consistent with Rule 3613(d), which provides in part that "[t]he utility's plan shall also provide the Commission with the best value employment metrics information provided by bidders under rule 3616 and by the utility pursuant to rule 3611."[18] This information is provided in Appendix C.

The Company has also provided projections of the RESA deferred account balance for three scenarios, including the Preferred ERP portfolio, Preferred CEPP, and CEP 775 500 Owned portfolio. The forecasted RESA deferred account balances are included as Appendix D.

4.1.2 Application of the Annuity Method to Bid Portfolios

The terms annuity method and replacement method represent different approaches for backfilling bids with lives that expire within the 2016-2054 Planning Period. In Paragraph 98 of Decision No. 18-0191, the Commission required the Company to

[18] Rule 3613(d) is not clear whether the best value employment metrics need to be provided for just the generation resources included in the preferred plan or all plans shown in the 120-Day Report. Public Service interprets Rule 3613(d) as requiring the Company to provide the best value employment metrics for generation resources included in all plans shown in the 120-Day Report, not just the "preferred plan," i.e., the Preferred CEPP.

present in the 120-Day Report portfolios developed using both backfilling methods. In compliance with that directive, the annuity method was applied in the development of bid portfolios that meet two distinct levels of RAP capacity need ordered for the ERP proceeding (0 MW and 450 MW). In addition, the model was used to develop bid portfolios involving aspects of the CEP that consider the early retirement of Comanche 1 and Comanche 2 and replacing the capacity of either one or two units within this ERP (775 MW and 1,110 MW). The resulting portfolios developed from that analysis are summarized in Table 8. The portfolios shown in Table 8 were selected using the same selection criteria used to develop the replacement method portfolios shown in Table 7 except that the portfolios were optimized using the annuity method. In some cases, applying the same selection criteria to the two sets of optimized portfolios resulted in the same portfolio of bids; in other cases, it did not.

Table 8 - Bid Portfolio Analysis Summary Results (Annuity Method)

		ERP 0 MW Portfolio	ERP 450 MW Portfolios (Com 1 & 2 Continue Operation)			CEP 1110 MW Portfolios (Early Retire Com 1 & 2)				CEP 775 MW Portfolios (Early Retire Com 1)		
Portfolio #		1	A2	3	4	A5	6	7	A8	A9	10	A11
Portfolio Name		LCP	LCP	Preferred	All Thermal	LCP	Preferred	Full Replacement	MLEP	LCP	500 Owned	MLEP
Nameplate Capacity (MW)	Notes:											
Solar		0	457	322	0	707	707	707	807	382	457	510
Wind		789	789	789	0	1131	1131	1131	1131	1131	1131	930
Storage		0	150	50	0	275	275	275	150	150	150	250
Gas		0	147	301	583	530	383	530	583	530	383	383
Total Nameplate MW		789	1543	1462	583	2643	2496	2643	2672	2193	2121	2073
Owned EER MW	1	0	0	0	0	0	500	500	800	0	500	599
Owned D/SD MW	2	0	0	301	583	383	383	383	583	383	383	383
Owned EER %	3	0%	0%	0%	0%	0%	27%	27%	41%	0%	31%	42%
Owned D/SD %	4	0%	0%	86%	100%	48%	58%	48%	80%	56%	72%	61%
RAP Firm Capacity (MW)												
Total Firm Capacity	5	79	547	554	534	1125	993	1125	1132	872	780	866
Excess of 2023 Need	6	(375)	93	100	80	346	213	346	353	93	0	87
2023 Reserve Margin %	7	11.0%	17.6%	17.7%	17.4%	21.2%	19.3%	21.2%	21.3%	17.6%	16.3%	17.5%
Planning Period PVRR ($M)												
Base Portfolio	8	$34,522	$34,394	$34,439	$35,366	$33,872	$33,934	$33,952	$33,966	$34,001	$34,056	$34,161
Electric Interconnection	9	$14	$57	$42	$4	$73	$73	$73	$97	$45	$57	$46
Electric Delivery	10	$113	$149	$149	$1	$113	$113	$113	$149	$113	$149	$113
LCI and Voltage Control	11	$12	$12	$12	$6	$44	$44	$44	$44	$44	$44	$23
DTA	12	$0	$0	$0	$0	$0	$82	$82	$203	$0	$82	$103
Operating Reserves	13	$7	$7	$7	$0	$30	$30	$30	$30	$30	$30	$13
Total PVRR		$34,667	$34,618	$34,649	$35,377	$34,133	$34,276	$34,294	$34,490	$34,232	$34,418	$34,458
PVRR Delta vs Preferred ERP	14	$17	($31)	$0	$727	($517)	($374)	($355)	($159)	($417)	($231)	($192)

Portfolios 1, 3, 4, 6, 7, and 10 in Table 8 are identical to those presented in Table 7 but with their Total PVRR calculated using the annuity method.[19] Portfolios A2, A5, A8, A9, and A11 contain variations of bid/projects different than those in Portfolios 2, 5, 8, and 9 of Table 8, as described above, and have therefore have been designated with the letter "A".

As discussed, Public Service has based its primary determination that the Preferred CEPP is cost-effective for customers through a comparison of portfolios that were

[19] Under the annuity method the lives of bids were extended to the end of the planning period at a price that equaled the annuity of the bidder proposed price (i.e., the levelized price) without any effects of inflation. For example, a 20 year PPA bid with a levelized cost of energy of $30/MWh and a 2020 in-service date, was extended under the annuity method at $30/MWh for each year from 2041-2054.

developed using the replacement method. Through that comparison, the Preferred CEPP shows $213 million in customer savings versus the Preferred ERP. Performing the same comparison using the portfolios developed with the annuity method shows the Preferred CEPP would provide $374 million in customer savings versus the Preferred ERP, which is $161 million higher than the level of savings derived using the replacement method.

In Decision No. C18-0191, the Commission noted "it is appropriate to give little weight to the annuity method applied to the CEP Portfolio for purposes of determining the cost-effectiveness of the early retirements of Comanche 1 and 2." For that reason, the Company's comparative analysis focuses on the replacement method for backfilling bids. Nevertheless, application of the annuity method as reflected above further reinforces the economic value the Preferred CEPP brings to customers as compared to the Preferred ERP.

Additional information regarding the development of bid portfolios analysis using both the annuity method and replacement methods for backfilling bids is included in Section 6 of this report.

4.2 The Preferred ERP and Preferred CEPP

This section compares the Preferred ERP and Preferred CEPP, the two foundational portfolios in this 120-Day Report, and builds on the discussion of these portfolios found in Section 2.0. This section first discusses how the Preferred ERP was developed and how it is different from the ERP LCP (Portfolio 2). Second, it goes into a more detailed comparison of the Preferred ERP and Preferred CEPP which, in turn, supports the Company's recommendation that the Preferred CEPP is a cost-effective resource plan.

4.2.1 Development of the Preferred ERP

Consistent with Rule 3601, the Company selected ERP Portfolio 3 to represent its preferred portfolio for meeting a 450 MW level of resource need. The Company started our selection process leading to the Preferred ERP by evaluating the results of modeling the least-cost ERP portfolio, which is reflected as Portfolio 2 in the table above. The Preferred ERP was determined as a result of the same extensive analysis that led to the development of all eleven portfolios discussed in detail in this section. The Company developed optimized portfolios using both the replacement method and the annuity method, as described above. This exercise resulted in many of the same bids being selected, illustrating the value of the bids under either approach. The analysis focused on the replacement method given Commission directives but all of this information was considered in evaluating the different portfolios and ultimately landing on Portfolio 3 as the Preferred ERP.

Another key part of this analysis, discussed in more detail below, was running the different portfolios through a suite of eleven sensitivities required by the Commission through both the Phase I Decision and Decision No. C18-0191. The results of these sensitivities are described below in Section 4.2.3 and all of the data associated with the analyses is provided in Appendix E. The sensitivity runs, as well as the annuity method optimizations, provided valuable stress-testing of the various portfolios using different modeling assumptions and under different futures. After evaluating this information, the Company ultimately determined that Portfolio 3 was the Preferred ERP. While Portfolio 3 carries a $14 million higher cost than the least-cost ERP portfolio, the Company believes Portfolio 3 contains attributes that make it a more balanced and more cost-effective ERP portfolio. These attributes include:

- Continued utilization of the existing 301 MW Manchief gas-fired facility. This facility provides fully dispatchable and flexible generation to the system at a very low cost.

- A balance of dispatchable/flexible gas and solar generation at 301 MW and 322 MW, respectively.

- 250 MW of solar with 50 MW of battery storage technology, which will enable the Company to advance understanding of this technology.

Portfolio 3 consists of the resources shown in Table 8 being added to fulfill the 450 MW need.

The Preferred ERP is used throughout this report as the benchmark against which the cost-effectiveness of the Preferred CEPP is measured. While the term "preferred" is used to describe Portfolio 3, the Company does so to comply with Commission directives to identify a preferred portfolio to meet the 450 MW RAP need. To be clear, the Company is not recommending Commission approval of the Preferred ERP; rather, Public Service recommends the Commission approve the Preferred CEPP.

4.2.2 Comparison of the Preferred CEPP and Preferred ERP

This section builds on the discussion of the Preferred CEPP in Section 2.0 and the discussion of the Preferred ERP in Section 2.0, as well as above. It provides additional comparative metrics between the Preferred CEPP and Preferred ERP.

<u>Specific Projects of the Preferred CEPP and Preferred ERP</u>

The Preferred CEPP is comprised of the eleven separate generating projects identified in Table 9.

Table 9 - Preferred CEPP Projects

Bid ID	Project Name	Technology	MW	Ownership	In-Service
X645	Neptune	Solar w/ Storage	250/125	IPP	2023
X647	Thunder Wolf	Solar w/ Storage	200/100	IPP	2023
X427	Picadilly	Solar w/ Storage	110/50	IPP	2023
S430	Owl Canyon	Solar	75	IPP	2023
S085	Hartsel	Solar	72	IPP	2023
W192	Cheyenne Ridge	Wind	500	Own	2021
W602	Bronco Plains	Wind	300	IPP	2021
W090	Mountain Breeze	Wind	169	IPP	2021
W301	Colorado Green	Wind (repower)	162	IPP	2019
G215	Manchief	Gas (existing)	301	Own	2022
G065	Valmont	Gas (existing)	82	Own	2022

Note: In-Service refers to the first summer the unit is available.

The Preferred CEPP strikes a balance of IPP and Company ownership of generation resources, though as discussed in Section 2.0 it does not result in the Company meeting the ownership targets established in the Stipulation of 50% for eligible energy resources and 75% for dispatchable and semi-dispatchable resources. The Preferred CEPP also contains a diverse mix of generation technologies including wind, solar, storage, and gas that in aggregate serve to replace 100% of the energy and 82% of the capacity provided from Comanche 1 and Comanche 2. As discussed below, the Preferred CEPP more than satisfies the 775 MW RAP firm capacity need resulting from the retirement of Comanche 1 in 2022.

The Preferred ERP is comprised of the six separate generating projects identified in Table 10.

Table 10 - Preferred ERP Projects

Bid ID	Project Name	Technology	MW	Ownership	In-Service
X672	Neptune	Solar w/ Storage	250/50	IPP	2023
S085	Hartsel	Solar	72	IPP	2023
W605	Bronco Plains	Wind	499	IPP	2021
W090	Mountain Breeze	Wind	169	IPP	2021
W302	Colorado Green	Wind (repower)	121	IPP	2019
G215	Manchief	Gas (existing)	301	Own	2022

Note: In-Service refers to the first summer the unit is available.

Generally speaking, all six of these projects are also contained within the Preferred CEPP. Three projects in the Preferred ERP (X672, W605 and W302) are variants (i.e., different sizes) of the projects included in the Preferred CEPP.

Portfolio Generation Mix Comparison

The Preferred CEPP includes four wind projects totaling 1,131 MW, three solar with battery storage projects totaling 560 MW, and two solar only projects totaling 147 MW. The Preferred CEPP also includes two existing gas-fired projects totaling 383 MW that provide both flexible generation to support overall operations and renewable integration as well as firm generation capacity to serve the peak needs of the system. Table 11 provides a summary comparison of the generation mix between the Preferred CEPP and the Preferred ERP portfolios.

Table 11 - Preferred CEPP and Preferred ERP Portfolio Generation Comparison

Generation Technology	Preferred CEPP (MW)	Preferred ERP (MW)	Delta MW
Wind	1131	789	+342
Solar	707	322	+385
Battery Storage	275	50	+225
Gas	383	301	+82
Comanche 1	0	325	(325)
Comanche 2[20]	0	335	(335)
Total	2496	2122	374

Portfolio Cost Comparison

The bid portfolio analysis captured both the costs and benefits of individual bid projects and the attendant system costs that arise when individual projects are combined into portfolios. The following costs were factored into the evaluation of bid portfolios:

1. _Base Portfolio:_ Baseline Phase II model costs inclusive of the costs and benefits resulting from the addition of the individual bids contained in a portfolio.

2. _Electric Interconnection:_ Costs associated with interconnecting projects to the Public Service electric transmission system (see Section 5 for details).

3. _Electric Delivery:_ Costs associated with delivering the power of each project from the point of interconnection to customer load (see Section 5 for details).

4. _LCI & Voltage Control:_ Costs associated with increasing the flexibility of existing Company-owned generation through installation of Load Commutated Inverter (LCI) equipment and costs associated with installation of additional equipment to maintain adequate transmission system voltages (see Section 5 for details).

5. _Deferred Tax Asset:_ Costs associated with the DTA for deferred Production Tax Credits (see Section 4.3 for details).

[20] Comanche 2 retires EOY 2025 which is outside the RAP for this ERP.

6. *Operating Reserves*: Costs associated with the level of operating reserves Public Service carries on its system to respond to contingency events (see Section 5 for details).

Table 12 provides a summary comparison of costs between the Preferred CEPP and Preferred ERP.

Table 12 - Preferred CEPP and Preferred ERP Portfolio Cost Comparison (PVRR $ Millions)

Cost Category	Preferred CEPP	Preferred ERP	Delta PVRR $M
Base Portfolio	$34,345	$34,691	($346)
Electric Interconnection	$73	$42	$31
Electric Delivery	$113	$149	($36)
LCI & Voltage Control	$44	$12	$32
Deferred Tax Asset	$82	$0	$82
Operating Reserves	$30	$7	$23
Total PVRR $ Millions	$34,687	$34,901	($213)

After incorporating the additional power supply-related costs discussed above, the Preferred CEPP is still the lower cost portfolio by $213 million on a present value basis. The favorable economics of the Preferred CEPP are influenced by the following factors:

1. *Robust pool of low cost renewable bids:* Bidders' ability to take full advantage of the full federal PTC and ITC combined with falling costs for renewable technologies resulted in a robust pool of wind, solar with battery, and solar bids at unprecedented pricing.

2. *Access to transmission made available by voluntary early coal retirements*: The voluntary early retirement of Comanche 1 and Comanche 2 serve to free up capacity on the existing Public Service transmission system, enabling more low cost renewable projects to be acquired before triggering the need for transmission system upgrades.

3. *Low cost flexible gas and battery bids:* Bidders offered flexible gas-fired and battery projects (paired with solar) at very competitive prices. These technologies bring a dual benefit to the Preferred CEPP in that they provide: (1) flexibility benefits for purposes of integrating the increased level of intermittent renewables in the Preferred CEPP, and (2) firm generation capacity for meeting the added peak resource needs attendant with the Preferred CEPP. The ability to acquire both benefits at favorable pricing is an important element of the economics of the Preferred CEPP.

In sum, the Preferred CEPP takes full advantage of these factors and as a result, provides considerable savings to customers. The Preferred CEPP includes unprecedented low pricing across a range of generation technologies including wind at levelized pricing between $11-18/MWh, solar between $23-$27/MWh, solar with storage between $30-$32/MWh and gas between $1.50 - $2.50/kW-mo.

Portfolio Ownership Comparison

With the Preferred CEPP, the Company is proposing to own three of eleven total generation projects that make up the portfolio: a single wind project and two gas projects. The owned wind project represents 500 MW (27%) of the 1,838 MW total eligible energy resources (EER) in the portfolio. The two gas facilities represent 383 MW (58%) of the total dispatchable and semi-dispatchable (D/SD) facilities in the portfolio.

In contrast, in the Preferred ERP all 1,111 MW (100%) of eligible energy resources are IPP-owned, and 301 MW of the total 351 MW (86%) of dispatchable and semi-dispatchable resources are utility-owned. Accordingly, the Preferred CEPP delivers more diversity of ownership than the Preferred ERP.

Portfolio RAP Firm Capacity Comparison

In Phase I of this proceeding, the Commission approved a 16.3% reserve margin to be used in establishing the minimum amount of firm generation capacity (i.e., resource need) to be acquired within the RAP of this ERP. For the ERP portfolios, the minimum resource need that all portfolios were required to fill was 454 MW.[21] For the CEP portfolios where both Comanche 1 and Comanche 2 were retired early or, where only Comanche 1 was retired early, the minimum resource need that all portfolios were required to fill was 779 MW (454 MW plus 325 MW).

Table 13 - Preferred CEPP and Preferred ERP Firm Capacity Comparison

Firm Capacity	Preferred CEPP	Preferred ERP
Resource Need (MW)	779	454
Resources Acquired within RAP (MW)	993	554
Resources in Excess of Need (MW)	213	100
Resulting Reserve Margin (%)	19.3%	17.7%
Portion of Comanche 2 filled early (MW)	213	NA

The combination of projects contained in the Preferred CEPP result in a 19.3% reserve margin in 2023 (at the end of the RAP), 3% above the minimum reserve margin ordered by the Commission. The practical effect of this outcome is that the Preferred CEPP fills 213 MW of Comanche 2 three years in advance of that unit's retirement.

[21] For simplicity, parties to this proceeding refer to the two levels of resource need as 450 MW for the ERP and 775 MW for the CEP.

As part of its decision in this proceeding, the Commission also directed the Company to present a portfolio that fills all of Comanche 2 within the RAP. In response, the Company has provided CEP Portfolio 7 (Full Replacement). The full replacement portfolio contains the same projects that make up the Preferred CEPP and adds one additional gas project, the existing 147 MW Brush 4D unit (Bid ID C172). With the addition of this project, the full replacement portfolio fills the entire 335 MW of Comanche 2 within the RAP at an added cost of $17 million PVRR.

<u>Section 123 Resources in the Preferred ERP and Preferred CEPP</u>

The Preferred CEPP includes two solar with battery storage projects that claim Section 123 status (Bid IDs X645 and X647) and another solar with battery storage project that did not claim Section 123 status (Bid ID X427). In comparison, the Preferred ERP includes one solar with battery storage project that claims Section 123 status. The Company notes that these projects were selected for inclusion in the Preferred CEPP and Preferred ERP based on the economic value of the bids, and *not* based on the Section 123 sensitivity methodology outlined in the Company's 30-Day Report Update. In other words, these projects were able to compete based upon economics and were included in bid portfolios as a result of their competitiveness. Results of the Section 123 sensitivity methodology are provided in Appendix F.

4.2.3 Sensitivity Analysis

To assess how changes to key modeling assumptions impact the costs and benefits of bid portfolios, a range of sensitivities were evaluated by the Company as part of the bid evaluation process. Sensitivities involve repricing the various bid portfolios developed under base case assumptions by varying a single base assumption such as future gas prices. Sensitivities do not result in changes to the timing or mix of bids in a portfolio. Ultimately, sensitivity analyses are a useful technique for assessing the robustness of a portfolio under different futures. Additional information regarding these sensitivities is provided in Appendix E of this report. For ease of reference, however, the list of sensitivities is provided below (including a citation to the decision where the Commission ordered inclusion of the sensitivity):

- Low Gas (Phase I Decision)
- High Gas (Phase I Decision)
- GPVM Adder (Phase I Decision)
- Low CO_2 (Phase I Decision)
- High CO_2 (Phase I Decision)
- Social Cost of Carbon (Phase I Decision)
- 0% Discount Rate (Phase I Decision)
- 3% Discount Rate (Phase I Decision)
- 4B Tail (Decision No. C18-0191)
- Accelerated Depreciation included (Decision No. C18-0191)
- Owned Wind Degradation (Decision No. C18-0191)

Figure 8 below shows the relative savings of the Preferred CEPP compared to the Preferred ERP portfolio under the various sensitivities. As can be seen, the base savings of $213 million either hold or increase under nearly all sensitivity cases. Under certain sensitivities, the savings increase significantly (e.g., 0% Discount Rate totaling nearly $1.4 billion in savings or Social Cost of Carbon showing over $1.0 billion in savings). Under other sensitivities, the savings remain stable at the $200 million level (e.g., High Gas, Low Gas).

In only the Owned Wind Degradation and Accelerated Depreciation sensitivities do the savings of the Preferred CEPP drop below the $200 million level. The Owned Wind Degradation sensitivity assumes higher than anticipated levels of wind degradation to only Company-owned wind projects. As the Preferred CEPP contains Company-owned wind projects and the Preferred ERP does not, the savings of the CEPP are impacted in that scenario. In the Accelerated Depreciation sensitivity, the value brought to the Preferred CEPP from the RESA reduction and rider recovery of accelerated depreciation is eliminated, leaving the CEPP to bear the full incremental cost of the early retirement. Nevertheless, even under this sensitivity, the Preferred CEPP shows over $100 million in savings versus the Preferred ERP portfolio.

Figure 8 - CEPP Sensitivity Analysis Results