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MAKING THE MOST OF THE POWER PLANT MARKET: **BEST PRACTICES FOR ALL-SOURCE ELECTRIC GENERATION PROCUREMENT**

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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

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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."

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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

[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.

[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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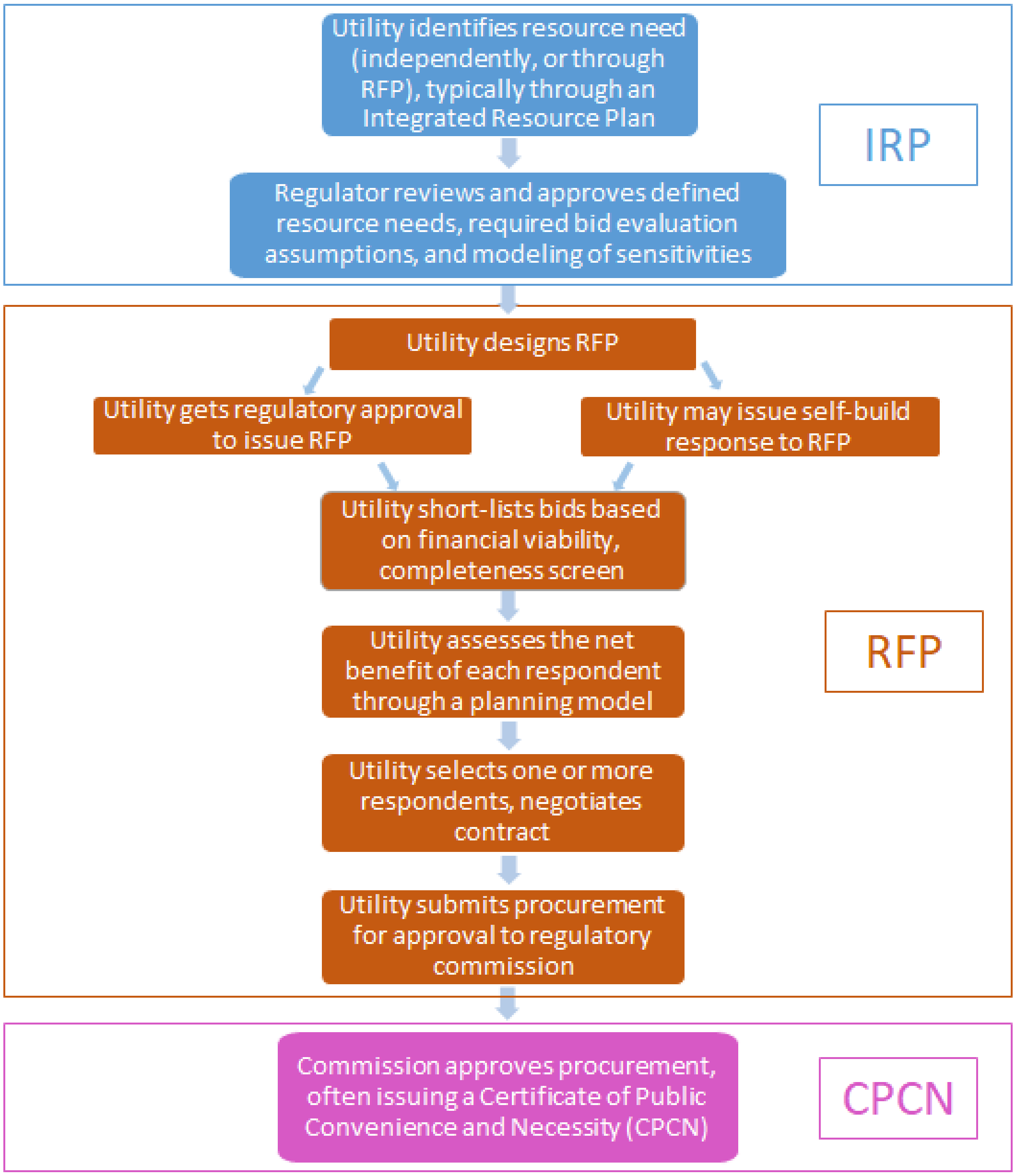
[11] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources 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.

[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.

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[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

[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.

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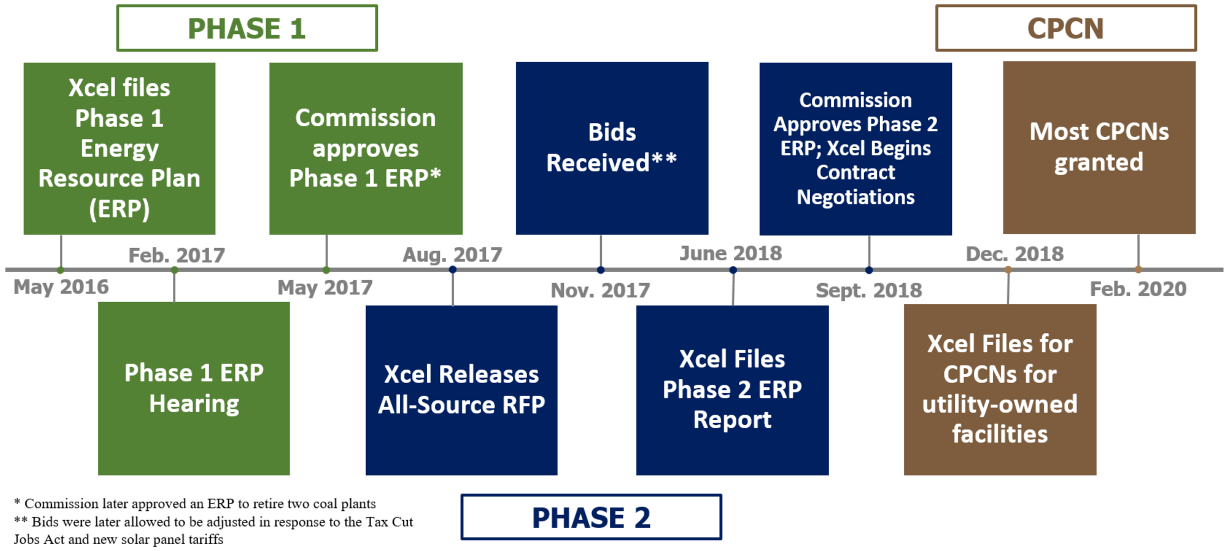
[26] Even though there are three bidding forms for intermittent, dispatchable and semi-dispatchable resources, all of these projects "compete" in the model by being modeled simultaneously.

[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

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[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

[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.

[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.

[civ] Georgia Power, *2020/2021 Renewable Energy Development Initiative, Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), Attachment C.

[cv] Georgia Power, *2015 Request for Proposals*, GPSC Docket No. 27488 (April 20, 2010), Attachment G, p. 6.

[cvi] Georgia Power, *2020/2021 Renewable Energy Development Initiative, Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), Attachment C, p. 4.

[cvii] Georgia Power, *2015 Request for Proposals*, GPSC Docket No. 27488 (April 20, 2010), Attachment G, p. 7.

[cviii] Minnesota Public Utilities Commission, *Order Approving Resource Plan with Modifications*, Docket No. E-015/RP-15-690 (July 18, 2016).

[cix] Minnesota Power, *2017 EnergyForward Resource Package*, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 3-34.

[cx] Minnesota Power, *2017 EnergyForward Resource Package*, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 3-32.

[cxi] Robert R. Stephens, *Direct Testimony on Behalf of Large Power Intervenors*, MPUC Docket No. E-015/AI-17-568 (January 19, 2018).

[cxii] Sedway Consulting, Inc., "Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation," *2017 EnergyForward Resource Package*, Appendix V, MPUC Docket No. E-015/AI-17-568 (July 28, 2017).

[cxiii] Minnesota Power, *2017 EnergyForward Resource Package*, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 6-13.

[cxiv] Minnesota Power, *2017 EnergyForward Resource Package*, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 6-14.

[cxv] Eric J. Palmer, *Direct Testimony on Behalf of Minnesota Power*, MPUC Docket No. E-015/AI-17-568 (November 9, 2017), p. 15-17.

[cxvi] Steve Rakow, *Direct Testimony on Behalf of the Division of Energy Resources*, MPUC Docket No. E-015/AI-17-568 (January 19, 2018), p. 36.

[cxvii] Steve Rakow, *Direct Testimony on Behalf of the Division of Energy Resources*, MPUC Docket No. E-015/AI-17-568 (January 19, 2018), p. 37.

[cxviii] Minnesota Public Utilities Commission, *Order Approving Affiliated-Interest Agreements with Conditions*, Docket No. E-015/AI-17-568 (January 24, 2019).

[cxix] Anna Sommer, *Direct Testimony on Behalf of Fresh Energy, et. al.*, MPUC Docket No. E-015/AI-17-568 (January 19, 2018).

[cxx] Minnesota Public Utilities Commission, *Order Approving Power Purchase Agreement*, MPUC Docket No. E-015/M-18-545 (January 23, 2019); Minnesota Public Utilities Commission, *Order Approving 10 MW Blanchard Solar Power Purchase Agreement and Cost Recovery Method*, MPUC Docket No. E-015/M-18-401 (October 2, 2018).

[cxxi] Fresh Energy et. al., *Clean Energy Organizations' Comments on Minnesota Power's 2015-2029 Resource Plan*, MPUC Docket No. E-015/RP-15-690 (June 30, 2017).

[cxxii] Comments of Commissioner Schuerger, Minnesota Public Utilities Commission, Agenda Meeting, (October 29, 2018).

[cxxiii] Comments of Commissioner Tuma, Minnesota Public Utilities Commission, Agenda Meeting, (September 7, 2017).

[cxxiv] Comments of Commissioner Lipshcultz, Minnesota Public Utilities Commission, Agenda Meeting, (October 29, 2018).

[cxxv] Minnesota Public Utilities Commission, *Order Approving Affiliated-Interest Agreements with Conditions*, Docket No. E-015/AI-17-568 (January 24, 2019).

[cxxvi] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 10.

[cxxvii] NIPSCO, *NIPSCO Announces Addition of Three Indiana-Grown Wind Projects* (February 1, 2019).

[cxxviii] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 54.

[cxxix] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 146.

[cxxx] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 171.

[cxxxi] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 172.

[cxxxii] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 171.

[cxxxiii] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), pp. 155, 171.

[cxxxiv] Mike Hooper, NIPSCO, *What Happens When Wind and Solar Win on Price?*, Advanced Energy Economy webinar (June 25, 2019).

[cxxxv] Omar Gallegos, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), pp. 20-22.

[cxxxvi] El Paso Electric, *2017 All Source Request for Proposals for Electric Power Supply and Load Management Resources* (June 30, 2017), p. 23.

[cxxxvii] Omar Gallegos, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), pp. 35-38.

[cxxxviii] El Paso Electric, *El Paso Electric Announces Results of Competitive Bid for New Generation* (December 26, 2018). The utility also announced 50-150 MW of additional wind and solar power "to provide for fuel diversity and energy cost savings." However, the utility did not successfully negotiate those projects. Wayne Oliver, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), Exhibit WJO-4, p. 45.

[cxxxix] Florida Office of Public Counsel, *Citizen's Post-Hearing Statement of Positions and Post-Hearing Brief*, FPSC Docket No. 140110-EI (September 10, 2014).

[cxl] Paul J. Hibbard, *Direct Testimony on Behalf of Calpine Construction Finance Company, L.P.*, FPSC Docket No. 20140110-EI (July 14, 2014).

[cxli] *Direct Testimony and Exhibits of Jeffry Pollock on Behalf of NRG Florida, LP,* Florida PSC Docket No. 20140110-EI (July 14, 2014).

[cxlii] Florida Power & Light Company, *Petition for Determination of Need for Okeechobee Clean Energy Center Unit 1*, FPSC Docket No. 150196-EI (September 3, 2015).

[cxliii]Sylvia Bender et al., *Implementing California's Loading Order for Electricity Orders,* California Energy Commission, (July 2005).

[cxliv] California Public Utilities Commission, *Resource Adequacy*.

[cxlv] Jeff McDonald, 'CPUC approves Edison energy deals,' *The San Diego Union-Tribune*, (November 19, 2015).; Peter Maloney, 'Why clean energy advocates are challenging SCE's historic storage buy,' *Utility Drive* (November 16, 2015).

[cxlvi] Eric Wesoff, Jeff St. John, "SCE Announces Winners of Energy Storage Contracts Worth 250MW," *Green Tech Media* (November 5, 2014). Further, to better understand the potential role of distributed energy resources in meeting local reliability needs, SCE began in parallel a preferred resources pilot that has demonstrated 200 MW of DERs "can be an effective means to manage load." Southern California Edison, *SCE Preferred Resources Pilot* (August 1, 2019).

[cxlvii] Peter Maloney, 'Why clean energy advocates are challenging SCE's historic storage buy," *Utility Drive* (November 16, 2015).

[cxlviii] California Public Utilities Commission, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, Rulemaking 16-02-007 (November 13, 2019).

[cxlix] California Public Utilities Commission, *Proposed Decision of ALJ Fitch*, Rulemaking 16-02-007 (September 12, 2019).

[cl] California Public Utilities Commission, *Proposed Decision Granting Motion Regarding Qualifying Capacity Value of Hybrid Resources with Modifications*, Rulemaking 17-09-020, (January 16, 2020).

[cli] Engie Storage et. al, *Joint Comments Regarding Qualifying Capacity Value Of Hybrid Resources*, CPUC Rulemaking 17-09-020 (December 20, 2019).

[clii] Dominion Energy Virginia, *2019 Solicitation for Peaking Power Supply Generation* (November 6, 2019).

[cliii] Dominion Energy Virginia, *Virginia Electric and Power Company's 2019 Update to 2018 Integrated Resource Plan*, VSCC Case No. PUR-2019-00141 (August 29, 2019).

[cliv] Virginia State Corporation Commission, *Integrated Resource Plan Filing*, Final Order in Case No. PUR-2018-00065 (June 27, 2019).

[clv] LS Power, *Doswell Letter to Virginia State Public Utility Commission and Attorney General Urges Suspension of Uncompetitive Solicitation Process for New Power Generation Peaking Resources* (November 21, 2019).

[clvi] Robert Walton, "Dominion suspends plan to add 1.5 GW of peaking capacity as Virginia faces gas glut," *Utility Dive* (December 5, 2019).

[clvii] 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.