STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of South Carolina	)	
Energy Freedom Act (House Bill 3659)	)	
Proceeding Related to S.C. Code Ann.	)	Docket Nos.
Section 58-37-40 and Integrated	)	2019-224-E
Resource Plans for Duke Energy	)	2019-225-E
Carolinas, LLC and Duke Energy	)	
Progress, LLC	)	

SURREBUTTAL TESTIMONY OF JOHN D. WILSON

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND UPSTATE FOREVER

Resource Insight, Inc.

APRIL 15, 2021

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, utility procurement practices, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further detailed in Exhibit JDW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 20 times before utility regulators in the Southeast U.S. and Nova Scotia, including testimony filed in six proceedings before the Public Service Commission of South Carolina (Commission). I have also appeared numerous times before various other regulatory and legislative bodies.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League and Upstate Forever.

Q: What is the purpose of your surrebuttal testimony?

A: The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Duke Energy witnesses Glen A. Snider, Matt Kalemba, and Nick Wintermantel regarding the process by which issues identified in an IRP proceeding are resolved, the practicality of making optimal resource planning decisions based on already-obsolete planning assumptions, and the importance of the Commission—rather than the regulated utility—reaching key determinations that shape procurement outcomes.

My surrebuttal testimony provides an alternative approach to resolving many of the technical arguments raised in rebuttal testimony regarding the 2020 Integrated Resource Plans (IRPs) filed by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP)(together, Duke Energy). Specifically, my surrebuttal testimony recommends moving to an all-source procurement process.

Q: How could the existing IRP process result in making resource procurement decisions based on obsolete planning assumptions?

Mr. Snider testifies that the Commission should "exercise caution" when considering proposed modifications to Duke Energy's 2020 IRPs, and suggests that adjustments to the IRPs should "be made on a going forward basis" to be filed in subsequent IRPs, such as in Duke Energy's 2022 IRPs, "*approximately 14 months* from the order required in these dockets."[1] Following the filing of the 2022 IRPs,

[1] Duke Energy, Rebuttal Testimony of Glen A. Snider, PSCSC Docket Nos. 2019-224-E and 2019-225-E (March 19, 2021), p.6, line 19 – p. 7, line 10. (Henceforth, "Snider Rebuttal.") (Emphasis in original.)

further time will elapse during which those adjustments will be reviewed by the Commission. My surrebuttal testimony addresses this delay and its consequences.

As Mr. Snider also testifies, an "unbalanced and unproven resource mix resulting from biases in system planning could have critical consequences for consumers."[2] However, Mr. Snider does not acknowledge the possibility that Duke Energy itself may have biases in system planning. Specifically, my surrebuttal testimony addresses the possibility that Duke Energy's assumptions about price, performance, and availability of generation alternatives reflect inaccurate and potentially biased information.

Q: Why should the Commission be concerned about this possibility?

A: These potentially inaccurate and biased assumptions could result in resource plans that are not reasonable and prudent—to the detriment of ratepayers.

Duke Energy has summarily rejected reasonable and substantiated critiques of its assumptions and modeling of generation alternatives in its rebuttal testimony. Should the Commission wish to direct Duke Energy to change any of its plans, it should not have to wait until 2022 to learn how Duke Energy proposes to respond to its direction, nor should it be limited to directing Duke Energy to conduct further studies to modify its IRPs which "may unnecessarily add costs for customers and administrative burden for ORS and the Commission."[3] Either waiting until the 2022 IRPs for answers or relying on direction of further studies would be untimely and a clumsy regulatory process.

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[2] Snider Rebuttal, p. 8, lines 9-10.

[3] Snider Rebuttal, p.6, line 19 – p. 7, line 10.

Q: What is the alternative to resolving some of these disputes through further study or a future IRP?

A: My surrebuttal testimony suggests an alternative process for resolving disputes about the price, performance and availability of resource alternatives—implementing an all-source electric generation procurement process. In 2020 I co-authored, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (Exhibit JDW-3) (henceforth "ASP Report"). More recently, I investigated solutions to challenges in the current procurement practices of Duke Energy, which are summarized in this testimony and discussed in detail in my report, *Implementing All-Source Procurement in the Carolinas* (Exhibit JDW-2) (henceforth "Carolinas ASP Report").

As discussed in Table 1 there are disputes as discussed below.

Q: What is all-source procurement?

A: With an all-source procurement approach, instead of the utility issuing a Request for Proposals (RFP) for a narrowly defined power plant to fill a specified capacity need, the utility issues an RFP in which all types of generation resources are allowed to compete. The ASP Report defines it more exactly as, "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."[4]

Regulators should use the integrated resource planning proceedings to make an explicit determination of need in terms of the load forecast that needs to be met,

[4] John D. Wilson, Mike O'Boyle, Ron Lehr, and Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, Energy Innovation and Southern Alliance for Clean Energy (April 2020), p. 6. (Henceforth, "ASP Report")

evolving system operating requirements, and existing plants that may need to be retired. Regulators should use this ***total system need*** approach as the starting point for approving an all-source procurement.

Q: Why should the Commission require Duke Energy to implement all-source procurement?

A: All-source procurement helps to ensure that a utility arrives at the optimal resource mix, reducing costs and risks to customers. The approach I recommend will enable Duke Energy to:

- Obtain price and performance information about generation alternatives directly from the marketplace, and
- Identify unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies.

The use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

Q: How does the all-source procurement process achieve this outcome?

A: This process is characterized by:

- Providing an economic basis for scheduling the retirement of coal plants, rather than waiting to act only when plants are already uneconomic;
- Resolving technical and policy questions that affect bid evaluation in advance, rather than during regulatory approvals;

- Obtaining price and performance information about generation alternatives directly from the marketplace, rather than from Duke Energy's staff research;
- Creating opportunities to meet electricity supply challenges more efficiently with a blend of technologies, rather than considering one solution at a time;
- Updating methods for coordinating of generation investment decisions with development of other resources such as energy efficiency and transmission, rather than making investment decisions in silos;
- Regulating the administration of the RFP process to ensure fair, efficient and competitive bidding with robust bid evaluation, rather than allowing for potential bias; and
- Expediting Commission certification of winning bids with a narrowed scope of review, reducing the risk of delay in heavily contested proceedings.

Q: What evidence supports your findings and recommendations for an all-source procurement process?

A: Experience in other states shows that all-source procurement is a proven approach that delivers clean, low-cost resource portfolios. The ASP Report reviewed four case studies of recent all-source procurements by vertically integrated utilities, and commented briefly on six other cases. The ASP Report recommends best practices drawn from each of the case studies, but emphasizes the model used by the Colorado Public Service Commission.

The Colorado model is also recommended by the North Carolina Energy Regulatory Process' (NERP) Competitive Procurement study group, as part of the state's Clean Energy Plan stakeholder process. The study group—co-chaired by representatives from Duke Energy and the solar industry—determined that the Colorado model "offered a good example of a successful generation procurement framework."[5]

Recently, the growing support for improving procurement practices by applying best practices in all-source procurement has been demonstrated by two additional reports on the topic. RMI and Lawrence Berkeley National Laboratory's reports provide additional research and support for principles of all-source procurement which I have found to be generally consistent with those recommended in the report I co-authored.[6]

The Carolinas ASP Report builds on the recommendations from the ASP Report and the NERP process, applying them to the integrated resource plans of DEC and DEP.

Q: Please summarize the approach to procurement discussed in Duke Energy's IRPs.

A: Duke Energy's 2020 IRPs include both a short-term action plan and a longer-term forecast of potential new generation plants and other resource options.[7] Resources identified in the short-term action plan are, for the most part, already approved or otherwise committed for construction or procurement. Thus, the Carolinas ASP

5 North Carolina Energy Regulatory Process, *Competitive Procurement Guidance Document* (December 2020).

6 Lauren Shwisberg, Mark Dyson, Grant Glazer, Carl Linvill, and Megan Anderson, *How to Build Clean Energy Portfolios: A Practical Guide to Next-Generation Procurement Practices*, RMI (2020); Dr. Fredrich Kahrl, *All-Source Competitive Solicitations: State and Electric Utility Practices*, Lawrence Berkeley National Laboratory (March 2021).

7 DEC and DEP file separate IRPs using a consistent methodology, publication format, and underlying assumptions. Both IRPs were submitted in identical form to the North Carolina Utilities Commission and Public Service Commission of South Carolina, along with supplementary materials reflecting each state's unique filing requirements.

Report focuses on the process by which Duke Energy will procure resources in the years immediately following the short-term action plan.

Vertically integrated utilities may procure resources through either all-source, comprehensive single-source, or restricted single-source RFPs. As explained in the ASP Report, "In contrast to an all-source procurement, in comprehensive and restricted single-source 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."[8]

Although not discussed explicitly in the IRPs, responses to data requests show that Duke Energy intends to procure generation resources beyond the short-term action plan using a comprehensive single-source RFP process.[9] In addition to its statutorily mandated competitive renewable energy procurements, Duke Energy "considers the IRPs as the primary vehicle to determine and guide the procurement of generation resources to meet future customer energy needs with RFP solicitations. Competitive solicitations are used to identify the most cost effective and reliable resources available in the marketplace consistent with the IRPs."[10]

Q: What will the procurement process look like if the Commission simply approves Duke Energy's IRPs?

A: DEP's IRP lays the foundation for issuing an RFP in late 2021 to obtain about 900 MW of peaking resource capacity for delivery in 2026, likely including performance specifications that will result in restricting the procurement to gas combustion turbine (CT) units.[11] In addition, Duke Energy will continue the

[8] ASP Report, pp. 2-3.

[9] Duke Energy's description of its RFP process is provided in the Carolinas ASP Report, Appendix D.

[10] Duke Energy, response to SELC DR-8-5. References to Duke Energy's responses to any "DR" are responses to data requests submitted in NCUC Docket E-100, Sub 165 and SCPSC Dockets 2019-224-E and 2019-225-E by the identified party.

[11] Carolinas ASP Report, pp. 5-6.

competitive procurement of renewable energy mandated under North Carolina law over the next several years. Other generation resource needs would be subject to further single-source RFPs, potentially after future IRPs update Duke Energy's plans.

Q: What is the problem with this result?

A: Relying on single-source RFPs for resources delivered in 2026 and beyond will not lead to the least-cost solution because the resulting portfolio is created by Duke Energy's assumptions about price, performance, and availability of generation alternatives. Even if each individual RFP results in competitive outcomes, the overall process will not take advantage of competition among technologies, and potential synergies across technologies.

Q: Would single-source RFPs for resources delivered in 2026 and beyond procure an optimal mix of resources?

A: No. Mr. Snider himself acknowledges that "In the current environment, many changes are occurring rapidly, on many fronts, including technology development and deployment and new laws and regulations impacting the long-term costs and benefit."[12] Even if Duke Energy's assumptions regarding the price, performance and availability of resource alternatives turn out to be correct, which is unlikely, they would be outdated by the time that bids were received. Mr. Snider argues against a requirement "to re-analyze options and to re-file a modified IRP to address more recent events that occurred after the 2020 IRPs were filed."[13] Mr. Snider appears to concede that an IRP filing may be "obsolete by the time it is filed and reviewed by ORS."[14] Relatedly, Mr. Kalemba states that "It is inevitable that new

[12] Snider Rebuttal, p. 42, line 22 through p. 43, line 1.
[13] Snider Rebuttal, p. 44, lines 9-11, p. 45, lines 1-2.
[14] Snider Rebuttal, p. 44, lines 9-11, p. 45, lines 1-2.

information will be available or factual bases for decisions will change after the IRP is finalized."[15]

Irrespective of whether Duke Energy's IRP relies on reasonable assumptions about resources available from the market, the IRP resource portfolio will not accurately forecast the optimal quantities of each resource. One reason that the IRP cannot forecast optimal portfolios is that procurements will result in more diverse bids than the IRP process considered, and there will be synergies with and among those bids that a generic IRP portfolio will omit. Another is that as Mr. Snider and Mr. Kalemba reasonably argue, events are moving too quickly to keep the official IRP updated—so it follows that the resulting IRP portfolios cannot remain optimal. Thus, the single-source RFPs that Duke Energy intends to use to implement the IRP will be based on obsolete IRP portfolios.

Unless the Commission directs Duke Energy to adopt an all-source procurement process, Duke Energy will continue to utilize a suboptimal process, including reliance on disputed assumptions regarding resolving disputes the price, performance and availability of generation alternatives. The biases that lead to such suboptimal processes are found in many large utilities—for example, the ASP Report discusses the dominance of natural gas and sources of bias in utility resource procurement.[16]

Q: What would the process look like if the Commission directs Duke Energy to implement your recommendations regarding all-source procurement?

A: Using an all-source procurement approach would involve considering bids to meet the ***total system*** need, including the 6,000-9,300 MW of winter rated capacity

[15] Duke Energy, Rebuttal Testimony of Matthew Kalemba, PSCSC Docket Nos. 2019-224-E and 2019-225-E (March 19, 2021), p. 7, lines 15-16. (Henceforth, "Kalemba Rebuttal.")

[16] ASP Report, pp. 13-18. These topics are further explored in John D. Wilson, Mike O'Boyle and Ron Lehr, "Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33 (2020).

identified from the IRPs over the 2026-2031 timeframe in a single, coordinated process. My estimate of Duke Energy's multi-year procurement opportunity is described further in the Carolinas ASP Report (Exhibit JDW-3).

As discussed above and in the Carolinas ASP Report, the use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

The Carolinas ASP Report discusses in further detail Duke Energy's need for an all-source procurement, the ways in which an all-source procurement would benefit customers, and the steps that the Commission should take to implement an all-source procurement.

Q: Please describe some of the main disputes among the parties about Duke Energy's assumptions regarding the price, performance and availability of generation alternatives.

A: Mr. Snider states that Duke Energy is "fully prepared to defend the inputs, assumptions and methodologies used in their 2020 IRPs."[17]

Table 1, below, summarizes the different parties' positions on disputed issues that could be resolved through an all-source procurement approach. The summaries in Table 1 are intended to capture the scope of the disputed topics; for brevity's sake the summaries may not fully express a party's position and may omit relevant disputed topics.

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[17] Snider Rebuttal, p. 48, lines 17-19.

Table 1: Comments and Responses Related to Duke Energy's Generation Alternatives Assumptions

Issue	Party Comment	Duke Energy Response
CT Capital Costs	Capital costs for gas-fueled combustion turbine (CT) units is lower than other publicly available estimates. ORS Report, p. 72.[18]	Use of brownfield sites and economies of scale support estimates. Snider, p. 99, Exhibit 9.
Capacity Value	Winter peak assumptions, including extreme historic winters, drive low winter solar capacity value, and the Astrapé study considered various levels of solar capacity. Existing fixed-tilt projects will often be replaced by tracking systems. Energy storage should be modeled to "preserve reliability" rather than for "economic arbitrage" when determining ELCC. Update solar capacity value study to reflect demand reduction potential in winter peak assessment report. Synergy between solar and storage omitted from capacity values. Lucas Direct, p. 55.[19] Olson Direct, pp. 23, 24.[20] ORS Report, pp. 39, 40, 74.	Capacity values based on studies by Astrapé, and will be reviewed in stakeholder process. Incorporating demand reduction into capacity value studies will be done in next update, and is not pressing. Used production cost model to ensure full valuation of battery storage. Choices regarding fixed-tilt vs tracking solar systems are based on reasonable assumptions. Assuming "preserve reliability" would reduce economic arbitrage value of solar. Extreme cold winter temperatures that have occurred should be considered in reliability studies. Synergy between solar and storage was considered because significant solar was included when studying ELCC of storage. ELCC of standalone storage in E3's analysis is unreasonably low. Even with adopting critiques, solar ELCC will remain low in

[18] Office of Regulatory Staff, Testimony of Anthony M. Sandonato, PSCSC Docket Nos. 2019-224-E (February 5, 2021), Exhibit AMS-1, *Review of Duke Energy Carolinas IRP*. (Henceforth, "ORS Report," page references are to the DEC Report, Exhibit AMS-1).

[19] Direct Testimony of Kevin Lucas on Behalf of the South Carolina Solar Business Alliance, PSCSC Docket Nos. 2019-224-E and 2019-225-E (February 5, 2021). (Henceforth, "Lucas Direct.")

[20] Direct Testimony of Arne Olson on Behalf of the South Carolina Solar Business Alliance, PSCSC Docket Nos. 2019-224-E and 2019-225-E (February 5, 2021). (Henceforth, "Olson Direct.")

Issue	Party Comment	Duke Energy Response
		winter which drives the capacity requirement. Kalemba Rebuttal, pp. 32-35, 41. Snider Rebuttal, pp. 126, 128-129. Wintermantel Rebuttal, pp. 12, 34, 35, 44.[21]
Post In-Service Capital Costs	Post in-service capital costs for new resource additions were not included in models. ORS Report, p. 87	The recommended costs were included in the models. Snider Rebuttal, p. 143.
Solar PPA	Include generic solar PPA proxy in models of $38/MWh. Lucas Direct, p. 6. ORS Report, p. 73.	Impossible to know how PPA would be priced by developer. Snider Rebuttal, pp. 118-119.
Solar Costs (ITC)	The federal ITC extension could reduce levelized costs of solar projects by $3-4/MWh. Lucas Direct, p. 35.	The extension of the Federal ITC occurred after IRP inputs were fixed in the late spring and summer months of 2020, and will be included in the 2021 update. Kalemba Rebuttal, pp. 7-8.
Solar Costs (Capital)	While the solar capital cost forecast is reasonable, the industry has often seen faster cost reductions than anticipated. Lucas Direct, p. 37.	No response to comment about faster cost reductions. Kalemba Rebuttal, p. 6.
Solar (O&M)	Solar O&M costs are higher than NREL now and in the future. Duke Energy's forecast should be discounted to reflect regionally lower costs and include a declining forecast. Lucas Direct, p. 38.	Solar O&M costs represent the cost to operate a solar facility in the Carolinas. Kalemba Rebutta, p. 10.
Solar Costs (Overall)	Duke Energy's levelized cost (LCOE) is higher than other publicly available estimates. ORS Report, p. 73.	The LCOE values shown by ORS are inconsistent; some cost forecasts are not possible in the Carolinas. Kalemba Rebuttal, p. 11.
Consideration of 2-Hour Storage	Two-hour batteries can cost-effectively defer the need for	There is limited need for narrow limited hour load shifting resources. Modeling studies don't

[21] Duke Energy, Rebuttal Testimony of Nick Wintermantel, PSCSC Docket Nos. 2019-224-E and 2019-225-E (March 19, 2021). (Henceforth, "Wintermantel Direct.")

Issue	Party Comment	Duke Energy Response
	other capacity, and can be used more often than DSM programs. Lucas Direct, p. 46.	fully capture all operational considerations. Kalemba Rebuttal, pp. 39-40.
Battery Storage (Capacity Factor)	The capacity factor assumption is too low. ORS Report, p. 73.	The capacity factor assumption is appropriate. Snider Rebuttal, p. 116.
Battery Storage (Capital)	Capital costs are at the high end of publicly available estimates. The solar+storage project forecast method is inconsistent with the standalone estimate and is not a least-cost approach. Lucas Direct, p. , 43. ORS Report, p. 72.15-17, 40	Battery storage costs are "use-case specific," uncertain, and difficult to rely on for planning purposes. IRP costs are based on "current and potential operating requirements." The solar+storage forecast is consistent and reflects appropriate judgement regarding how developers will provide systems that provide service for the duration of the solar project. Kalemba Rebuttal, pp. 15, 16, 21, 25.
Battery Storage (O&M)	O&M costs are out of line with other estimates. ORS Report, pp. 72-73.	The O&M assumptions will be corrected in the 2021 update. Kalemba Rebuttal, p. 28.

The disputes summarized in Table 1 could be resolved through a well-designed and administered procurement process. No amount of testimony can rebut the information provided by bidders in an all-source procurement that follows best practices.

Q: Are there disputed issues that cannot be resolved through the RFP process?

A: Yes. A number of key issues should be resolved by the Commission in advance of authorizing Duke Energy to issue an all-source RFP or evaluate bids. As discussed above, an integrated resource planning proceeding should result in an explicit determination of system need in terms of the load forecast that needs to be met, evolving system operating requirements, and existing plants that may need to be retired. The Commission should use this ***total system need*** approach as the starting point for approving an all-source procurement, and this determination should guide Duke Energy as it issues the RFP and conducts the bid evaluation.

Similarly, the Commission should resolve technical and policy questions that affect bid evaluation in advance, rather than during regulatory approvals. Several of such issues are discussed in detail in Appendix B of the Carolinas ASP Report. As the Carolinas ASP Report anticipated, several of these issues have been disputed in parties' direct and Duke Energy's rebuttal testimony, as summarized in Table 2. The summaries in Table 2 are intended to capture the scope of the disputed topics; for brevity's sake the summaries may not fully express a party's position and may omit relevant disputed topics.

Table 2: Comments and Responses Related to Technical and Policy Questions that Affect Bid Evaluation

Issue	Party Comment	Duke Energy Response
Natural Gas Pricing	Duke Energy's natural gas pricing biases the model towards building and running natural gas units. Duke Energy's relatively flat natural gas price forecast is insufficiently sourced due to relying on a small sample of forward market purchases. Lack of projects to expand interstate gas supply limits market access. Duke Energy should make greater use of a fundamentals-based forecast. Lucas Direct, p. 63. ORS Report, pp. 50-51.	Duke Energy agreed to discuss its forecast with stakeholders prior to the 2022 IRP. Fundamental price forecasts have resulted in excess costs to customers. Longer term futures are liquid and robust, and are a sounder basis for valuation of future purchases. Snider Rebuttal, pp. 64-65, 68, 76. Wintermantel Rebuttal, pp. 17-28.
CO_2 Emissions Reduction	Duke Energy's CO_2 price forecasts are reasonable representations of legislative proposals through 2035. ORS Report, p. 54.	The Base Case without Carbon Policy is Duke Energy's "Appropriate Plan" at this time for use in avoided costs proceedings and other regulatory

Issue	Party Comment	Duke Energy Response
		matters.[22] It is the role of policymakers, not utilities, to set emissions standards. Snider Rebuttal, pp. 2, 38-39, Exhibit 3.
Solar Interconnection Limits	Duke Energy has interconnected more than the 500 MW annual cap in two prior years, and is trending towards larger projects, so it should be able to interconnect more. Lucas Direct, p. 58.	The construction of transmission network upgrades is constrained due to other work and projected energy demand. Kalemba Rebuttal, p. 36.
Reserve Margin (Methodology)	Duke Energy's reserve margin uses a method that does not put firm and non-firm capacity on a level playing field. An alternative industry-standard method would be an easily-implemented improvement. Olson Direct, p. 26.	Changing reserve margin methods would require a significant re-design of the current planning reserve margin process with little impact on the selection of resources. Snider Rebuttal, p. 62.
Reserve Margin (Extreme Low Temperatures)	Climate change may make more recent weather conditions more likely than the extreme low temperatures that have only occurred prior to 1985. Duke Energy's extrapolation of loads based on experience during mild temperatures is inaccurate. Power plant outage rates under extreme cold are overstated. ORS Report, pp. 35-36. Wilson Direct, pp. 8, 10-11.[23]	Stakeholders failed to recommend alternatives for winter modeling. Duke Energy agreed to discuss this in future stakeholder processes and IRPs. The relationship between the historical data and synthetic data shows a reasonable correlation. Extreme events are occurring more frequently, and the use of older weather data provides a more diverse set of weather conditions, which can recur as suggested by the Texas event. Snider Rebuttal, pp. 53, 54, 58. Wintermantel Rebuttal, pp. 17, 24, 25.

[22] Even though Mr. Snider represents the Base Case *without* Carbon Policy as the "Appropriate Plan," Duke Energy's IRP report conveys the opposite impression, emphasizing the Base Case *with* Carbon Policy in various figures and tables. DEC IRP, pp. 10, 20, 42, 100, 101, 105, 106, 107. Duke Energy presented only one figure in the main body of the IRP report illustrating the "without" carbon policy case on a similar standalone basis. DEC IRP, p. 109.

[23] Direct Testimony of James F. Wilson on Behalf of Natural Resources Defense Council et al, PSCSC Docket Nos. 2019-224-E and 2019-225-E (February 5, 2021). (Henceforth, "Wilson Direct.")

The disputes summarized in Table 2 should be resolved by the Commission in advance of an all-source procurement because they will affect the bid evaluation process. While Duke Energy's evidence on each of these points is essential to the Commission's consideration, the utility's evaluation of that evidence may be influenced by bias or simply because "that's how its always been done." As summarized below, each of these points can make a meaningful difference to procurement outcomes.

- Solar interconnection limits may constrain the contribution of otherwise-economically favorable resources and thus favor competing resources.
- The reserve margin methodology determines the overall amount of resources required, the seasonal benefit (summer vs winter) of each resource,[24] and the contribution of each specific resource towards reliability.
- Natural gas pricing determines the dispatch of existing and new gas units relative to other existing and potential generation.
- CO_2 emissions reduction policy determines the dispatch and retirement of existing and new fossil generation relative to alternatives.

Thus, advance resolution of these and other similar issues will help avoid biasing the bid evaluation process with the preferences of the utility. The Commission should resolve these and other similar issues prior to finalizing approval of Duke Energy's bid evaluation process for future all-source resource procurement.

Q: Please summarize your surrebuttal testimony.

A: The rebuttal testimony of Duke Energy witness Mr. Snider describes a flawed process for resolving issues identified in an IRP proceeding. The process used by Duke Energy will lead to single-source procurements being conducted based on

[24] Kalemba Rebuttal, p. 29, line 9 through p. 30, line 7.

already-obsolete planning assumptions. I have provided examples from the rebuttal testimonies of Duke Energy witnesses Mr. Kalemba and Mr. Wintermantel that illustrate disputed issues that could be definitively resolved through a procurement process. Mr. Snider's recommendation that the Commission wait until the 2022 IRPs for Duke Energy's latest opinion on the price, performance and availability of resource alternatives would be untimely and would likely result in a clumsy, unnecessary assessment of the market through a regulatory process.

Instead of relying on single-source RFPs for resources delivered in 2026 and beyond, the Commission should direct Duke Energy to use an all-source procurement process, following the recommendations I outline below. Unless the Commission directs Duke Energy to adopt an all-source procurement process, Duke Energy will continue to utilize a suboptimal process. Its use of single-source RFPs relies on disputed assumptions regarding the price, performance and availability of generation alternatives to determine how much of each resource category will be procured.

My surrebuttal testimony has also discussed how the rebuttal testimony of Duke Energy witness Mr. Snider, Mr. Kalemba and Mr. Wintermantel discusses key determinations that shape procurement outcomes. As discussed above and in the Carolinas ASP Report, it is important that the Commission make those key determinations in order to obtain the best possible outcome for customers, avoid biasing the bid evaluation process with the preferences of the company, and avoid time consuming proceedings after the bid evaluation report is submitted to the Commission.

Q: Please summarize your recommendations.

A: My recommendations, discussed more fully in the Carolinas ASP Report, are as follows:

1. The Commission should require Duke Energy to define need in terms of the load forecast that needs to be met, evolving system operating requirements and retirement options, and existing plants that may need to be retired. The Commission should approve the load forecast, including all related methods and assumptions, and the method for evaluating retirements of existing plants. (Page 5)[25]
2. The Commission should enhance the connection between Duke Energy's generation procurement process and customer-based resources by authorizing energy efficiency programs *at least* to the level indicated by the cost of generation resources, and by requiring similar comparisons for tariffs and policies affecting customer-funded distributed energy resources. (Page 10)
3. The Commission should use the IRP proceeding to affirmatively resolve disputes over model constraints in order to expedite the evaluation of bids and approval of portfolios during the procurement process. (Page 11)
4. The Commission should give Duke Energy clear direction as to what government policies and related model assumptions be used in the IRP model for both planning and bid evaluation purposes. (Page 12)
5. The Commission should consider establishing an all-source procurement process that combines its authority under Act 62 for competitive renewable energy procurement with its authority to establish RFP rules for constructing a power plant. This could be initiated by ordering a pilot procurement process in the current IRP proceedings under statutory authority, following up with a rulemaking that incorporates any lessons learned from the pilot. (Pages 14-15, 33-34)

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[25] Page numbers refer to the Carolinas ASP Report.

6. The Commission should direct Duke Energy to design and propose an approach that that solicits bids to meet the ***total system need*** for the entire 2026-2031 time period, but evaluates and contracts in a staged all-source RFP process, as detailed in the report. (Pages 19-20)

7. After approval of the staged all-source procurement process, the Commission should authorize Duke to swiftly issue an all-source RFP for the delivery of generation resources in the 2026-2031 time frame. (Page 20)

8. The Commission should proactively support the development of data and analytic methods necessary to support evaluations of near-term emerging technologies. (Page 21)

9. In defining resource eligibility, the Commission should also determine how to incorporate demand-side management resources and emerging generation resource technologies. (Pages 21-24)

10. The Commission should renew existing coordination mechanisms to link all-source procurement with evaluation of longer-term emerging technologies, grid investments, and energy efficiency (and related) programs, as well as consideration of existing zero-carbon facilities. (Page 24)

11. In order to ensure that the all-source procurement process does not prematurely drive down avoided costs and the cost-effectiveness of energy-efficiency and other existing zero-carbon resources, the Commission could provide for delivery flexibility in generation contracts. (Page 28)

12. The Commission should develop a list of modeling methods and assumptions that will be resolved in the IRP process prior to application in bid evaluation and direct Duke Energy to file an initial proposal. In addition to many technical methods and assumptions, the proposal should include a forecast for carbon

policy and also any "non-price" factors and attributes that require subjective consideration, either in determining whether a bid is qualified or potentially as a post-model evaluation ranking adjustment. (Pages 30-31)

13. The Commission should direct Duke Energy to propose a complete set of RFP documents, and encourage Duke Energy to blend its current practices with model documents from the Colorado procurement process. (Page 31)

14. The Commission should direct Duke Energy to follow the model bid evaluation process, culminating in a bid evaluation report with all model data made available for review by regulatory staff and qualified intervenors. (Page 32)

15. The Commission should identify any specific objectives that it wishes to be included in alternative portfolios in the bid evaluation report. (Page 33)

16. The Commission should proactively address structural bias and prevent improper self-dealing, by evaluating the effectiveness of existing requirements and updating them to ensure that they require:
    a. Involvement of an independent monitor or evaluator;
    b. Transparent assumptions and analysis in a procurement process;
    c. Detailed information provided to potential bidders;
    d. Utility codes of conduct to prohibit improper information sharing with utility affiliates;
    e. Careful disclosure and review of "non-price" factors and attributes, particularly if they may advantage self-build or affiliate bids. (Page 35)

17. The Commission should establish and enforce standards that do not just defer to the utility's claims of confidentiality when establishing reasonable protections for confidential information. (Pages 35-36)

18. The Commission should allow third parties to participate in decision-making related to finalizing the RFP process and conducting the bid evaluation modeling process to help correct any bias that may exist within the utility's procurement staff. (Page 36)

19. The Commission should establish a procedure for approving or modifying a resource portfolio. The procedure should include a request for comments on the bid evaluation report from parties. The procedure should preserve the Commission's option to conduct a full evidentiary hearing if significant concerns are raised, but should otherwise proceed based on the written record. (Page 36)

20. The Commission should collaborate with the North Carolina Utilities Commission and explore the potential for holding joint hearings on many, if not all, of the above decisions. (Pages 36-38)

Q: Does this conclude your surrebuttal testimony?

A: Yes.

Exhibit JDW-1

JOHN D. WILSON

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

2019–Present **Research Director, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric-utility rate design. Designs and evaluates conservation programs for electric utilities, including conservation cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Managed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony on topics of resource planning, renewable energy, energy efficiency to utility regulators. Directed litigation activities, including support of expert witnesses in the areas of rate design, resource planning, renewable energy, energy efficiency, and resource procurement. Conducted supporting research and policy development. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air pollution reduction, including ozone, air toxics, and other related pollutants in the industrial, utility, and transportation sectors. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Interim Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for projects assessing environmental and resource issues in the Rio Grande / Rio Bravo river basin and across the Greater Houston region. Coordinated task force and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

"Urban Areas," with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

"Quality of Life and Comparative Risk in Houston," with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

"Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs," with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

"Monopsony Behavior in the Power Generation Market," with Mike O'Boyle and Ron Lehr, *Electricity Journal*, August-September 2020.

REPORTS

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Houston Environmental Foresight Committee, *Seeking Environmental Improvement*, Houston Advanced Research Center, January 1996.

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Office of Program Policy Analysis and Government Accountability, *Best Financial Management Practices for Florida School Districts*, Report No. 97-08, October 1997.

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Office of Program Policy Analysis and Government Accountability, *Review of the Expedited Permitting Process Coordinated by the Governor's Office of Tourism, Trade, and Economic Development,* Report No. 98-17, October 1998.

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06, August 1999.

"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

“Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast,” Southern Alliance for Clean Energy, November 2014.

“Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance,” Southern Alliance for Clean Energy, July 2015.

“Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems,” prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

“Seasonal Electric Demand in the Southeastern United States,” Southern Alliance for Clean Energy, March 2017.

“Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System,” Southern Alliance for Clean Energy, March 2017.

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“Energy Efficiency in the Southeast, 2018 Annual Report,” with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

“Solar in the Southeast, 2018 Annual Report,” with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

“Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report,” with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

“Seasonal Electric Demand in the Southeastern United States,” with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

“Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,” with Mike O’Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

“Monopsony Behavior in the Power Generation Market,” *The Electricity Journal* 33, with Mike O’Boyle and Ron Lehr (2020).

“Review of Nova Scotia Power’s 2020 Integrated Resource Plan,” prepared for the Nova Scotia Consumer Advocate, NSUARB Matter No. M08059, with Paul Chernick (January 2021).

PRESENTATIONS

“Clean Energy Solutions for Western North Carolina,” presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

“Energy Efficiency: Regulating Cost-Effectiveness,” Florida Public Service Commission undocketed workshop, April 25, 2008.

"Utility-Scale Renewable Energy," presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

"An Advocates Perspective on the Duke Save-a-Watt Approach," ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

"Building the Energy Efficiency Resource for the TVA Region," presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

"Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement," Southeast Energy and Environmental Leadership Forum, Nicholas Institute for Environmental Policy Solutions, August 2020.

“Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,” Indiana State Bar Association, Utility Law Section, Virtual Fall Seminar, September 2020.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas’ 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power’s 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power’s 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

Nova Scotia UARB Matter No. M09579, direct testimony with Paul Chernick in Nova Scotia Power's application for the Gaspereau Dam Safety Remedial Works on behalf of the Nova Scotia Consumer Advocate. Alternatives to proposed project, project contingency factor, estimation of archaeological costs, and replacement energy cost calculation.

Nova Scotia UARB Matter No. M09707, direct testimony with Paul Chernick on Nova Scotia Power's 2020 Load Forecast on behalf of the Nova Scotia Consumer Advocate. Impacts of recession, application of end-use studies, improvements to forecast components, and impact of time-varying pricing.

California PUC Docket A.19-10-012, direct and rebuttal testimony with Paul Chernick in San Diego Gas & Electric's application for the Power Your Drive Electric Vehicle Charging Program on behalf of the Small Business Utility Advocates. Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

California PUC Docket A.19-08-013, direct testimony in Southern California Edison's 2021 general rate case (track 2) on behalf of the Small Business Utility Advocates. Reasonableness of remedial software costs to be included in authorized revenue requirement.

Georgia PSC Docket Nos. 4822, 16573 and 19279, direct, rebuttal and surrebuttal testimony in Georgia Power Company's PURPA avoided cost review on behalf of the Georgia Large Scale Solar Association. Reviewing compliance with prior Commission orders. Application of capacity need forecast in projection of avoided capacity cost. Calculation of cost of new capacity. Proposal of standard offer contract.

California PUC Docket A.19-11-019, direct testimony with Paul Chernick in Pacific Gas & Electric's 2021 general rate case (phase 2) on behalf of the Small Business Utility Advocates. Cost of service methods. Rate design, including customer charges, demand charges, real time pricing tariffs, TOU differentials and periods.

Nova Scotia UARB Matter No. M09548, direct testimony on the audit of Nova Scotia Power's Fuel Adjustment Mechanism on behalf of the Nova Scotia Consumer Advocate. Reasonableness of fuel contract costs. Scope of study on dispatch practices. Impact of greenhouse gas shadow pricing. Compliance issues related to resource planning.

2021 **California PUC** Docket R.20-11-003, direct and reply testimony on rulemaking to ensure reliable electric service in the event of an extreme weather event on behalf of the Small Business Utility Advocates. Modifications to Critical Peak Pricing programs and Time of Use periods. Modifications to load management programs.

Exhibit JDW-2

Resource Insight, Inc.

Implementing All-Source Procurement in the Carolinas

Duke Energy Carolinas & Duke Energy Progress

John D. Wilson, MPP
Research Director, Resource Insight, Inc.

February 26, 2021

Prepared for
Natural Resources Defense Council, Sierra Club,
Southern Alliance for Clean Energy, South Carolina Coastal Conservation League and Upstate Forever
For submission in
NCUC Docket E-100, Sub 165, and
SCPSC Dockets 2019-224-E and 2019-225-E

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Background and Purpose

All-source procurement is an approach in which a utility issues a Request for Proposals (RFP) in which all types of generation resources are allowed to compete, instead of issuing a RFP for a narrowly defined power plant to fill a specified capacity need. In *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (ASP Report), my co-authors and I suggested that, "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."[1]

Among the reasons that the Commissions should require Duke Energy to implement all-source procurement are to develop state electric plans that:

Provide an economic basis for scheduling the retirement of power plants, rather than waiting to act only when plants are already uneconomic;

Resolve technical and policy questions that affect bid evaluation in advance, rather than during regulatory approvals;

Obtain price and performance information about generation alternatives directly from the marketplace, rather than from Duke Energy's staff research;

Create opportunities to meet electricity supply challenges more efficiently with a blend of technologies, rather than considering one solution at a time;

Update methods for coordinating of generation investment decisions with development of other resources such as energy efficiency and transmission, rather than making investment decisions in silos;

Regulate the administration of the RFP process to ensure fair, efficient and competitive bidding with robust bid evaluation, rather than allowing for potential bias; and

[1] John D. Wilson, Mike O'Boyle, Ron Lehr, and Mark Detsky, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, Energy Innovation and Southern Alliance for Clean Energy (April 2020) , p. 6. (Hereafter, "ASP Report")

Expedite Commission certification of winning bids with a narrowed scope of review, reducing the risk of delay in heavily contested proceedings.

All-source procurement helps ensure that a utility arrives at the optimal resource mix, reducing costs and risks to customers. The approach I recommend will enable Duke Energy to:

- Obtain price and performance information about generation alternatives directly from the marketplace, and
- Identify unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies.

The use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

Experience in other states shows that all-source procurement is a proven approach that delivers clean, low-cost portfolios. The ASP Report reviewed four case studies of recent all-source procurements by vertically integrated utilities, and commented briefly on six other cases (including North Carolina). The ASP Report recommends best practices drawn from each of the case studies, but emphasizes the model used by the Colorado Public Service Commission.

The Colorado model is also recommended by the North Carolina Energy Regulatory Process' ("NERP") Competitive Procurement study group. The study group—co-chaired by representatives from Duke Energy and the solar industry—determined that the Colorado model "offered a good example of a successful generation procurement framework."[2]

Implementing All-Source Procurement in the Carolinas builds on the recommendations from the ASP Report and the NERP process, applying them to the integrated resource plans of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP).

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[2] North Carolina Energy Regulatory Process, *Competitive Procurement Guidance Document* (December 2020). (Hereafter, "NERP")

Duke Energy's IRPs include both a short-term action plan and a longer term forecast of potential new generation plants and other resource plans.[3] Generation plants identified in the short-term action plan are, for the most part, already approved or otherwise committed for construction or procurement. Thus, this report focuses on the process by which Duke Energy will procure generation resources in the years immediately following the short-term action plan.

The ASP Report shows how regulators have used the integrated resource planning proceedings to make an explicit determination of need in terms of the load forecast that needs to be met, evolving system operating requirements, and existing plants that may need to be retired. Regulators should use this ***total system need*** approach as the starting point for approving an all-source procurement.

Today, vertically-integrated utilities may procure resources through either all-source, comprehensive single-source, and restricted single-source RFPs. As explained in the ASP Report, "In contrast to an all-source procurement, in comprehensive and restricted single-source 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."[4]

Although not discussed explicitly in the IRPs, Duke Energy intends to procure generation resources beyond the short-term action plan using a comprehensive single-source RFP process.[5] In addition to its statutorily mandated competitive renewable energy procurements, Duke Energy "considers the IRPs as the primary vehicle to determine and guide the procurement of generation resources to meet future customer energy needs with RFP solicitations. Competitive solicitations are used to identify the most cost effective and reliable resources available in the marketplace consistent with the IRPs."[6]

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[3] DEC and DEP file separate IRPs using a consistent methodology, publication format, and underlying assumptions. Both IRPs were submitted in identical form to the North Carolina Utilities Commission and Public Service Commission of South Carolina, along with supplementary materials reflecting each state's unique filing requirements. References citing "DEC and DEP" throughout this report are to their respective 2020 IRPs. Where a single page number is cited, the reference is to the DEC report pagination. References to Duke Energy's responses to any "DR" are responses to data requests filed in NCUC Docket E-100, Sub 165 and SCPSC Dockets 2019-224-E and 2019-225-E by the identified party. No confidential information is included in this report.

[4] ASP Report, pp. 2-3.

[5] Duke Energy's description of its RFP process is provided in the ASP Report, Appendix D.

[6] Duke Energy, response to SELC DR-8-5.

Duke Energy's IRP lays the foundation for issuing an RFP in late 2021 to obtain about 900 MW of peaking resource capacity for delivery in 2026, likely including performance specifications that will result in restricting the procurement to gas combustion turbine (CT) units. In addition, Duke Energy will continue and potentially expand the competitive procurement of renewable energy mandated under North Carolina law and permitted under South Carolina law over the next several years. Other generation resource needs would be subject to further procurements, potentially after future IRPs update Duke Energy's plans.

Relying on single-source RFPs for resources delivered in 2026 and beyond will not lead to the least-cost solution because the resulting portfolio is created by Duke Energy's assumptions about price, performance, and availability of generation alternatives. Even if each individual RFP results in competitive outcomes, the overall process will not take advantage of competition among technologies, and potential synergies across technologies.

Using an all-source procurement approach would involve considering bids to meet the ***total system*** need, including the 6,000-9,300 MW of winter rated capacity identified from the IRPs over the 2026-2031 timeframe in a single, coordinated process.

Unless the Commissions direct Duke Energy to adopt an all-source procurement process, Duke Energy will continue to utilize a suboptimal process. This report examines Duke Energy's need for an all-source procurement, the ways in which an all-source procurement would benefit customers, and the steps that the Commissions should take to implement an all-source procurement.

Determining the Need for an All-Source Procurement

How should the Commissions define the procurement need?

In conventional procurements, such as Duke Energy's prior RFPs, utilities specify a numeric capacity need (or goal) and technology eligibility, either by name or by restrictive performance standards. A well-designed all-source procurement takes a very different approach: the advance determination of need does not establish the specific capacity or technology to be procured.

The ASP Report recommends that regulators use resource planning proceedings to make an explicit determination of need – but ***define total system need in terms of the load forecast that needs to be met, and existing***

plants that may need to be retired.[7] Thus, system need should not be defined simply in terms of a specific energy or capacity target, but rather in terms of all system needs—and that should encompass many aspects of what can be called system operating requirements,[8] such as needs for flexible capacity, system inertia, and, simply, lower operating costs. The Commissions should approve the load forecast, including all related methods and assumptions, and the method for evaluating retirements of existing plants. Ideally, the determination of need would ensure that the procurement is open to any technology, and any siting location.

The resulting portfolio should satisfy the need created by the forecast, evolving system operating requirements and retirement options, with the utility procuring any amount of nameplate capacity of a mix of technologies based on cost-effectively meeting the need. The ***total system need*** can give a more optimal result because it is more expansive and less restrictive than a specific, numeric capacity target and technology specification.

When does Duke Energy's IRP anticipate procurements?

Using a conventional definition of need, DEC identifies its first year of need as 2026 and DEP as 2024.[9] Duke Energy's anticipated procurements are defined in various ways in the IRP.

DEP lays the foundation for issuing an RFP in late 2021 to obtain about 900 MW of peaking resource capacity for delivery in 2026, likely including performance specifications that will result in restricting the procurement to gas combustion turbine (CT) units. In addition, both DEC and DEP will continue the competitive procurement of renewable energy mandated under North Carolina law over the next several years.

Thus, even though DEP identifies its "first year of need" as 2024, Table 1 shows that DEP does not forecast resource additions until 2026 in its base case. DEC identifies its first year of need as 2026, but does not forecast substantial resource additions until 2030.

For purposes of this report, I am identifying 6,000 MW as the conventional definition of need that Duke Energy anticipates procuring, and I am assuming

[7] ASP Report, p. 20.

[8] Examples of relevant system operating requirements are discussed in Appendix B, such as renewable interconnection limit, rooftop solar forecast, DSM programs, joint planning/balancing, availability of pipeline capacity, and reserve requirements.

[9] DEC and DEP, Ch. 13, p. 113.

that any procurements would begin delivering resources in 2026. The capacity figures in Table 1 reflect Duke Energy's assessment of resource contribution to winter peak. Duke Energy recognizes solar systems as providing winter peak capacity of 1% of nameplate capacity. For example, in 2025 the 0.75 MW of solar represents 75 MW of nameplate solar capacity.

Table 1: Winter Capacity Resource Additions, 2024-2031 (winter-rated MW)

	2024	2025	2026	2027	2028	2029	2030	2031
Duke Energy Carolinas								
Combined Cycle								
Combustion Turbine							457	457
Solar		1	1	1	1	20	20	20
Battery								
Compliance Renewables	9	(14)	2	30	24	29	14	9
Duke Energy Progress								
Combined Cycle					1,224	1,224		
Combustion Turbine			457	457		913		
Solar							38	38
Battery								457
Compliance Renewables			(9)	19	18	14	(4)	11
Total Resource Additions	**9**	**(13)**	**451**	**507**	**1,267**	**2,200**	**525**	**992**

DEC and DEC Tables 12-E. "Compliance Renewables" calculated as the net change in cumulative renewables capacity (removing undesignated solar and battery).

How soon does Duke Energy believe plant retirements could be advanced?

While it is reasonable to assume that Duke Energy's nuclear, gas and hydroelectric resources will continue to operate for their expected license terms or until fully depreciated, the high fixed costs associated with maintaining coal plants can result in accelerated retirement dates. The potential to cost-effectively replace coal plants is an additional source of resource need in addition to power contract expirations and load growth.

In this IRP, Duke Energy conducted a coal plant retirement analysis to determine the most economic retirement dates.[10] Although these retirement dates are used in Duke Energy's base cases, Duke Energy states that these dates are not a commitment to retire in those exact years. Duke Energy also considered how early retirement could be advanced based on the timeline to bring replacement natural gas generation into service at the same location.[11]

If Duke Energy advanced coal unit retirements to those "earliest practicable retirement dates," then the net increase in conventionally defined capacity need would be about 3,300 MW, as summarized in Table 2. Any procurements to advance these retirements would begin delivering generation in 2026.

Table 2: Advancement from Economic to Earliest Practicable Retirement, 2024-2031 (winter-rated MW)

	2024	2025	2026	2027	2028	2029	2030	2031
Duke Energy Carolinas								
Marshall 1 – 4					2,078			
Belews Creek 1 & 2						1,220		
Duke Energy Progress								
Mayo 1			746			(746)		
Roxboro 1 & 2					1,053	(1,053)		
Total Retirement Advancement			**746**		**3,131**	**(579)**		

DEC and DEC Tables 11-A and.A-11.

Considering both Duke Energy's evaluation of anticipated procurements and the earliest practicable retirement dates, Duke Energy's total procurements could be as large as about 9,300 MW (winter-rated capacity) between 2026-3031.

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[10] DEC and DEP, Ch. 11.

[11] DEC and DEP, Appendix A, pp. 173-176.

How does resource cost uncertainty affect the need determination?

Duke Energy's evaluation of the anticipated procurements and the economic retirement dates are outputs of its IRP modeling, which depends on its forecasted cost of new generation. If the forecasted cost of new generation declines, then the economic retirement dates for some plants should advance to an earlier date. Similarly, if new generation costs decline, then it will be cost-effective to advance or increase procurements and reduce the dispatch of existing generation resources. Thus, cost forecasts for new generation resources are a critical input into the need determination.

Relying on Duke Energy's IRP cost forecasts is likely to lead to the "wrong" procurement, potentially resulting in stranded costs that could have been avoided with a better cost forecast, or s a more competitive procurement process.

As discussed in Appendix C, forecasts of clean energy technologies have often wildly overestimated costs – and even though Duke Energy is forecasting substantially lower clean energy costs in the future, it may still be far too gradual.

Duke Energy even acknowledges that market pricing can differ so much from IRP cost forecasts that a comparison "yields little value in planning space."[12] Whether due to an erroneous forecast of market prices or to the cumulative effect of advantageous pricing due to "unique circumstances," when Duke Energy's "planning space" fails to represent the marketplace, its IRP forecast of capacity needs will inefficiently blend technologies.

The solution is demonstrated in all-source procurement case studies, which show the benefits to a utility that:

- Obtains price and performance information about generation alternatives directly from the marketplace. The PNM all-source procurement received 735 bids – developers are clearly willing to participate in highly competitive procurement.
- Identifies unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies. Xcel Colorado needed to replace 660 MW of coal plants, but was offered over 58,000 MW (nameplate) of generation resources and procured 2,458 MW, representing 1,100 MW of firm capacity.[13]

[12] Duke Energy, response to SELC DR-8-1(d).

[13] ASP Report, p. 33.

In a single-source procurement, generation cost forecasts are key assumptions in the model used to determine the capacity objective, or "need," of the RFP. If battery prices decline by 80%, rather than 50%, Duke Energy's plans for resource procurement will be outdated and misaligned in terms of cost, schedule and price – likely resulting in procuring the "wrong" resources. These problems can be mitigated by obtaining market-based pricing at the exact time that it is needed for evaluation and contract negotiation by Duke Energy, or any other vertically integrated utility. To minimize the impact of generation cost forecasts on the RFP, the ASP Report recommends what this report is referring to as a ***total system need*** approach to need determination.

What is the total system need approach to need determination?

The ***total system need*** approach to need determination will require the Commissions to oversee a process that ensures close scrutiny of the utility's assumptions about future electric load (including energy efficiency programs); operation of the existing generation fleet and transmission system; and relevant government policies. These activities are already part of the IRP process, but in addition to applying closer scrutiny, it is likely that regulators will need to require the utilities to make some adjustments.

Future electric load

Future electric load in the context of designing a procurement process is probably best considered as net load: customer electric usage (reflecting the reductions from energy efficiency programs and regulations) minus the power supplied by customer-funded distributed energy resources (DERs).

The ASP Report did not identify cases in which utility-funded energy efficiency programs or customer-sited DERs were procured through an all-source RFP.[14] Those customer-side resources require different evaluation approaches than utility-side resources and are thus not well suited for procurement in the same RFP. Estimating the scale of the customer-side resources requires in-depth scrutiny of program marketing and delivery plans, as well as market potential. A wide range of participant costs and benefits should also be taken into account in estimating program uptake and in evaluating the economics of the measures. In comparison, an all-source procurement for generation resources can expect a number of similarly-

[14] Demand response programs are an exception as discussed below.

qualified developers to offer competitive pricing, enabling the final evaluation to rely on quantifiable differences.

Even though the challenges to including most energy efficiency and DERs in an all-source procurement may not be easily overcome, the Commissions should enhance the connection between Duke Energy's generation procurement process and customer-based resources. An essential connection is ensuring that up-to-date procurement pricing information informs relevant policies and program management decisions.

Among those decisions are Commission reviews of energy efficiency programs, which should be authorized *at least* to the level indicated by the cost of generation resources. Energy efficiency programs can be modeled in system planning models with load shapes and cost information in comparison to generation bids to determine whether certain energy efficiency programs affect the optimal selection of bids. Such an integrated evaluation can then inform the Commission's review of utility-funded energy efficiency programs.

The Commissions should also require similar comparisons for tariffs and policies affecting customer-funded distributed energy resources.

Operation of existing generation fleet and transmission system

Duke Energy's approach to estimating the earliest practicable retirement date improves on its historical methods, and illustrates how changing economics can redefine the existing generation fleet and transmission system. Below, I will show how this approach can be leveraged to determine the retirement portion of the ***total system need*** approach to need determination. The Commissions should not neglect review of the "remaining" generation fleet and transmission system.

On one hand, the IRP models may need to be enhanced to better characterize evolving system operating requirements. For example, relatively crude assumptions regarding system inertia requirements, but greater reliance on resources that utilize "synthetic" inertia may require different modeling techniques. Other areas for enhanced modeling might include flexible capacity requirements, characterization of extreme weather events, and locational benefits of generation.

On the other hand, existing IRP models may contain unreasonable assumptions about the existing system in the form of operating constraints.

For example, the PNM case study in the ASP Report discusses an all-source procurement involving replacement resources for a retiring coal plant. PNM's proposed portfolio was challenged, in part, based on how PNM constrained the model's consideration of imported power. The import limit is one of several model constraints that effectively favored the selection of gas resources over solar resources.[15] New Mexico regulators accepted the critique of intervenors, and approved an alternative portfolio with more solar power than PNM had recommended.[16] Similar model constraints are included in Duke Energy's IRP model and should be reviewed for reasonableness, such as its 500 MW/year solar interconnection limit.[17] The ASP Report recommends that the IRP proceeding be used to affirmatively resolve disputes over model constraints in order to expedite the evaluation of bids and approval of portfolios during the procurement process.[18]

Relevant government policies

Duke Energy's IRP includes two base cases, one with and one without a carbon policy. Although the two base cases differ, it is arguable that the carbon policies examined in the two base cases are not different enough, with the carbon policy case only reducing emissions by 10% more than the without carbon policy case by 2035.[19] For example, Nova Scotia Power's 2020 IRP considered a "comparator" case (based on existing policy), a net-zero 2050 case, and an accelerated net-zero 2045 case.[20] The three cases show similar greenhouse gas emissions reductions in 2030, but diverge sharply beginning in the early 2030s.

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[15] ASP Report, p. 26; New Mexico Public Regulation Commission, *Recommended Decision on Replacement Resources – Part II*, Case No. 19-00195-UT, June 24, 2020, p. 122.

[16] New Mexico Public Regulation Commission, *Order on Recommended Decision on Replacement Resources – Part II*, Case No. 19-00195-UT, July 29, 2020.

[17] Duke Energy, response to ORS DR-2-26(a).

[18] ASP Report, p. 24.

[19] DEC and DEP, p. 8.

[20] Nova Scotia Power, *2020 Integrated Resource Plan*, NSUARB Matter No. M08929 (November 27, 2020), p. 50.

To its credit, Duke Energy evaluated several alternative resource portfolios, including earliest practicable coal retirements, high wind, high SMR, and no new gas generation, as well as several sensitivity analyses.[21]

Just as fuel cost forecasts presume that market prices will evolve based on known resource or technology characteristics, the government policy forecast used to inform the ***total system need*** determination should not presume the status quo. Locking in today's conditions for the future electric grid is a recipe for the creation of stranded costs.

Instead, the forecast should anticipate how government policy and other external requirements will shape the electric system.[22] Arguably, it is an extreme assumption to assume that the regulatory landscape will remain unchanged for the next decade or two. During the IRP process, the Commissions should give Duke Energy clear direction as to what government policies and related model assumptions be used in the IRP model for both planning and bid evaluation purposes.

Conducting an All-Source Procurement

What is an all-source procurement, and how is it authorized?

"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."[23]

The previous section discusses how the Commissions should implement the ASP Report recommendation that regulators use resource planning proceedings to make an explicit determination of need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. Once the ***total system need*** is approved by the Commissions, Duke Energy would use that need determination as the starting point for approving an all-source procurement.

[21] DEC and DEP, Ch. 12, p. 89.

[22] Carbon policy is not the only relevant consideration. The Commissions' view on state policies, such as North Carolina's "Ridge Law," will have a significant impact on eligibility and bid evaluation.

[23] ASP Report, p. 6.

The ***total system need*** determination is one of several characteristics that differentiate all-source procurements from other procurement practices. Other important characteristics are a procurement that:

- Provides an economic basis for scheduling the retirement of power plants, rather than waiting to act only when plants are already uneconomic;
- Resolves technical and policy questions that affect bid evaluation in advance, rather than during approval hearings;
- Obtains price and performance information about generation alternatives directly from the marketplace, rather than from utility staff research;
- Creates opportunities to meet electricity supply challenges more efficiently with a blend of technologies, rather than considering one solution at a time;
- Updates methods for coordinating of generation investment decisions with development of other resources such as energy efficiency and transmission, rather than making investment decisions in silos;
- Regulates the administration of the RFP process to ensure fair, efficient and competitive bidding with robust bid evaluation, rather than allowing for potential bias; and
- Expedites Commission certification of winning bids with a narrowed scope of review, reducing the risk of delay in heavily contested proceedings.

The resulting procurement should differ from a conventional single-source procurement—the amount of resources procured may differ in both the mix and the capacities of each technology required from what was projected in the initial modeling.

North Carolina laws and regulations

North Carolina has three requirements related to procurement. First, NCUC Rule R8-60 requires investor-owned utilities to discuss the results of RFPs in their IRPs, but without any specific performance requirements.

Second, NC GS 62-110.1 requires the utility to obtain a certificate that demonstrates that power plant construction is consistent with the NCUC's plan for generation capacity. Although the NCUC could adopt a process to guide utility RFPs as its plan for capacity expansion, its current plan is a compilation of orders and information from relevant proceedings.[24]

Third, and most significant, is the Competitive Procurement of Renewable Energy (CPRE) program, authorized by North Carolina HB 589 in 2017 (NC GS 62-110.8). Two solicitations have been completed for DEC and DEP.[25] The CPRE legislation is extensive, and resulted in detailed rules (NCUC Rule R8-71) governing the RFP process and bid evaluation.

All-source procurement could proceed under an expanded scope of the NCUC's annual plan for capacity expansion, relying significantly on the CPRE process for model rules.

South Carolina laws and regulations

South Carolina's laws and regulations governing competitive procurement are in transition due to the South Carolina Energy Freedom Act (Act 62, May 2019). In 2019, the SCPSC initiated a proceeding to explore rules for a competitive renewable energy procurement process under the authority of SCC 58-41-20(E)(2). Although the proceeding has been underway for over a year, it has been delayed over the question of whether establishing such a competitive procurement program is in the public interest.[26]

Act 62 also amended South Carolina law to permit the SCPSC to establish rules for conducting an RFP and evaluating the bids prior to applying for the certificate required to construct a power plant (SCC 58-33-10). However, the existing SCPSC Rule 103-304 has not been updated and provides little additional guidance beyond reference to the statute.

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[24] The NCUC files an "Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina," pursuant to NC GS 62-110.1(c). The report summarizes information from utility IRPs and information from other Commission records and files. This report may also be considered the Commission's "plan," and NC GS 62-110.1(e) conditions a certificate for constructing a generation facility on "a finding that construction will be consistent with the Commission's plan for expansion of electric generating capacity."

[25] DEC and DEP, Ch. 14, pp. 117, 123; Appendix E, and Attachments I and II. DEC's "First Year of Need" is stated as 2026. See discussion on page 3.

[26] SCPSC, Commission Directive, Order No. 2020-779 (November 18, 2020), SCPSC Docket No. 2019-365-E.

Duke Energy also identified a SCPSC order related to the Distributed Energy Resource Program as providing guidance for a 40 MW RFP.[27]

All-source procurement could proceed in South Carolina in a process that combines both Act 62 procurement processes into a single process.

Duke Energy's recent procurements

Duke Energy has conducted 13 RFPs since 2012, as summarized in Appendix A. Most of these have focused on renewable energy, particularly solar power. Two were focused on gas generation. None could be considered all-source procurements.

Some of the key features of the procurements include:

- Most were combined DEC/DEP procurements, with different goals for each utility.
- Most allowed for either power purchase agreements (PPAs) or turnkey ownership, but specific terms and preferences varied among the RFPs.
- Legislative requirements constrained the location and other qualifications.

Duke Energy's current RFP process is documented in Appendix D. Overall, the Competitive Procurement of Renewable Energy (CPRE) procurements demonstrate the most proactive review and oversight practices. In contrast, the other procurements were initiated by Duke Energy without obtaining pre-approval of the process, bid evaluation methods, or other essential terms.

Duke Energy's history of procurements demonstrates a preference for using comprehensive single-source RFPs to procure generation resources, a practice it intends to continue (see page 5). Duke Energy does not obtain pre-approval by either Commission for issuance of an RFP, "Unless required by statute or the respective Commission."[28]

Nonetheless, both Commissions appear to have authority to establish all-source procurement rules. North Carolina's CPRE procurement rules provide an excellent starting point that both Commissions could use to develop all-

[27] SCPSC, *Order Addressing Distributed Energy Resource Program and Approving Settlement Agreement*, Order No.2015-514, SCPSC Docket No. 2015-53-E, p. 14; and Order No.2015-515, SCPSC Docket No. 2015-55-E, p. 14. See, Duke Energy, response to SELC DR-8-2(a).

[28] Duke Energy, response to SELC DR-8-2(c).

source procurement rules. The Commissions could begin by ordering a pilot procurement process in the current IRP proceedings under statutory authority, following up with a rulemaking that incorporates any lessons learned from the pilot.

How should near-term procurements be conducted?

Prior to 2026, Duke Energy's short-term action plan envisions further renewable energy procurements. State policy driving these procurements includes the North Carolina Competitive Procurement of Renewable Energy (CPRE) program and South Carolina Act 62. These state policies will accelerate the pace of adopting renewable energy resources, which help lower fuel costs in the near term.

The CPRE program has procured two tranches, all solar (some projects including storage). A third tranche is envisioned, but its minimum size will depend on how much "transition" renewable capacity (projects with legally enforceable obligations to deliver power to Duke Energy prior to enactment of the CPRE program).[29]

The NCUC may expand the size and number of CPRE procurements, as HB 589 provided for:

> … the offering of a new renewable energy resources competitive procurement in an amount to be procured as determined by the Commission, based on a showing of need evidenced by the utility's most recent IRP approved by the Commission … N.C. Gen. Stat. § 62-110.8

South Carolina Act 236 also provides a vehicle for near-term expansion of renewable energy procurements. The SCPSC is authorized to"

> … open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility's balancing authority area if the commission determines such action to be in the public interest. SCC 58-41-20(E)(2)

The SCPSC has opened such a generic docket (Docket No. 2019-365-E).

Thus, both the CPRE and SC Act 62 provide a strong basis for further renewable energy procurements to provide fuel-free, zero-carbon resources that provide near-term ratepayer savings. Duke Energy has the capability and legal authority to conduct such procurements for resource delivery prior to

[29] DEC and DEP, Attachment II, p. 8.

2026—as 2026 is the first practicable year for resource delivery under an all-source procurement.

Even in the absence of a specific statutory mandate or other policy directive, there may be reasons to proceed with a renewable resource procurement. A competitive solicitation for renewable energy resources could result in procurement of fuel-free, zero-carbon resources, reducing fuel costs and displacing fossil generation for the benefit of ratepayers. The SC PSC recognized this in its recent order on the Dominion South Carolina IRP, finding that:

> Even in the absence of a need for additional capacity, procurement of energy from solar and/or storage resources in the near term may result in savings for ratepayers, if those resources can provide energy to the system more economically than existing generation resources or alternatives contemplated in the IRP. Competitive procurement of such generation resources creates an opportunity for ratepayer savings.[30]

Further, consideration should be given to whether earlier procurement of resources not immediately needed for capacity or energy is economically beneficial (e.g., to take advantage of an expiring tax credit).

Under the circumstances discussed above, either commission may find cause to authorize Duke Energy to issue a renewable RFP, subject to parameters established by the commission. It would be impractical to include deliveries earlier than 2026 in an all-source procurement pilot due to the timeline for delivering many resources. A solar procurement for delivery in the 2022-2025 timeframe could proceed in parallel with the more complex all-source procurement envisioned in this report, which is intended to result in procurement in the 2026-2031 period.

How should all-source RFPs be scheduled?

Even though DEP's "First Year of Need" is stated as 2024 in the IRP,[31] my review of Duke Energy's base case indicates that about 6,000 MW of procurements, plus the potential for an additional 3,300 MW of procurements

[30] Public Service Commission of South Carolina Order No. 2020-832 at 21, Docket No. 2019-226-E (Dec. 23, 2020), https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39.

[31] DEP, Ch. 13, p. 114.

to advance the retirement of coal units, are anticipated in the 2026-2031 timeframe.[32] (See pages 5-8)

As discussed above, Duke Energy currently has a clear preference for the comprehensive single-source RFP process (see page 5). For a new construction CT project to fill a winter 2026 need, Duke Energy states that the RFP should be conducted in winter 2021.[33] Without direction from the Commissions, it is likely that DEP will rely on its IRP submission as the basis to initiate a gas-only procurement—likely missing out on cleaner, cheaper resources that could meet system needs.

Because of DEP's imminent procurement plans, the Commissions should take immediate action to schedule an all-source procurement process. Taking a holistic, all-source procurement viewpoint will require the Commissions to consider the varying development schedules for potential resources. Some existing, uncontracted resources may be available nearly immediately. Solar or storage projects that are in varying stages of permitting and interconnection may also take a bit longer. And still further out, the development schedule for otherwise proven technologies, such as offshore wind, may lack a proven track record.

These scheduling considerations mean that the Commissions would need to resolve whether the all-source procurement should be conducted as a single RFP covering the entire ***total system need*** for generation resources in the 2026-2031 timeframe, or as multiple RFPs. The single RFP approach is described in the ASP Report's Model Process for Bid Evaluation.[34] However, since Duke Energy's procurement needs are so substantial, it could be impracticable to evaluate such a large RFP in a single pass through its IRP model.

On the other hand, breaking the procurement up into multiple rounds could compromise the goal of optimizing the entire resource procurement. Since the bids would only provide pricing for the immediate resource needs of each

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[32] It may be advisable to allow for delivery of a restricted class of technologies in advance of 2026. According to Duke Energy, "The portfolios in DEP utilizing the earliest practicable coal retirement schedule vary from those that use the most economic retirement schedule, having a significant buildout of batteries from 2022 through 2025 to facilitate the earliest practicable retirement of Mayo station." Duke Energy, response to NC Public Staff DR-7-4.

[33] Duke Energy, response to NC Public Staff DR-3-27.

[34] ASP Report, p. 31.

round, those resource choices would be optimized against Duke Energy's existing generic resource cost forecasts. As discussed above, I recommend giving generic resource cost forecasts as little consideration as possible.

In evaluating these two alternatives, the Commissions should consider recognition of technologies that require a longer lead time. Duke Energy's IRPs discuss offshore wind and zero emissions load following resources (ZELFRs) such as green hydrogen.[35] An approach that gives long lead time resources a market opportunity, with sufficient lead time, would be preferable to one that only permits projects that can be developed on the timescale of a gas-fueled power plant.

A staged process for bid evaluation

Taking the best of both options, I recommend that the Commissions direct Duke Energy to design and propose an approach that solicits bids to meet the ***total system need*** for the entire 2026-2031 time period, but evaluates, models and contracts in stages. The process could follow this approach:

- Open an RFP soliciting bids for delivery of generation resources in the 2026-2031 time period.
- After conducting an initial screening analysis, update the IRP model's generic resources to representing typical cost and performance data of the most competitive bids. Subdivision of technology categories may be appropriate to ensure consideration of varying performance opportunities.
- Model bids on a year-by-year basis, competing against generic resources in future years. For the 2026 bid year, the actual bids would compete against generic resources for 2027+.
- After evaluating all bids through 2031, construct portfolios for more advanced evaluation, as suggested in the ASP Report and discussed in more detail below (see page 31).[36]

The Commissions may need to allow Duke Energy to fine-tune the bid vs generic resource evaluation method during the bid evaluation process. If so, the fine-tuning should follow guidelines that prescribe a balance between:

- Optimizing among technologies;
- Optimizing across time;

[35] DEC and DEP, Ch. 16.

[36] See discussion of Colorado and New Mexico case studies. ASP Report, pp. 20, 26, 31.

- Committing to sufficient contracts for deliveries later in the period to attract bids for those years; and
- Maintaining future opportunity by reserving a portion of the economic portfolio to future generic resources, with re-solicitation in future RFPs.

Any fine-tuning should be reviewed by the independent evaluator and fully explained in the bid evaluation report (both topics are explored below, beginning at page 31).

To implement this staged approach, the Commissions should direct Duke Energy to propose a more detailed process and, after its approval, proceed to swiftly issue an all-source RFP for the delivery of generation resources in the 2026-2031 time frame. The alternative approach would be to focus on a more limited delivery period (e.g., 2026-2027) and rely on resource cost forecasts for longer-term procurements. As discussed above, relying on cost forecasts will compromise the goal of optimizing the entire resource procurement on market data.

In either case, Duke should anticipate following up with additional RFPs after each IRP.

What resources should be eligible to participate?

Although resource eligibility for an all-source procurement is simple in concept, there are several complications that require advance resolution. As discussed in the ASP Report, "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."[37] On its face, this definition of eligibility encompasses considering solar (including dispatchable and hybrid configurations), wind (including offshore sites), biomass, combined heat and power, battery storage, imported power, natural gas, and any other market-ready technology that can be financed, developed and delivered on a reliable schedule.

Ensuring the neutrality of the requirements for proposed generation plants is essential because rules or practices adapted from single-source RFPs can disadvantage or exclude cost-effective bids. The ASP Report discusses the dominance of natural gas and sources of bias in utility resource

[37] ASP Report, p. 6.

procurement.[38] Generally speaking, vertically integrated utilities have a financial bias towards over-procurement of capacity, a financial bias towards self-built generation, and an organizational culture that currently favors gas-fueled generation. The best practice to remove bias and ensure a neutral RFP process is for Commissions to conduct advance review of procurement assumptions and terms, as discussed below (page 29).

Another practice the Commissions should consider is to proactively support the development of data and analytic methods necessary to support evaluations of near-term emerging technologies. For example, Duke Energy could begin commissioning meteorological towers to independently verify wind speed history in order to evaluate wind projects.[39]

In defining resource eligibility, the Commissions should also determine how to incorporate demand-side management resources and emerging generation resource technologies. These resource options can play a role in an all-source procurement, but with some limitations.

Demand-side management resources

Utilities are also gaining experience with considering third-party demand-side management (DSM) resources in comparison to generation resources. As discussed elsewhere in this report, there are practical reasons to procure utility-funded energy efficiency programs in a separate, but coordinated process. Third-party DSM developers can aggregate the actions of many customers into a virtual power plant, and some third-party programs can meet bid qualification standards on much the same basis as generation resources.

Third-party DSM programs are recommended in Duke Energy's studies of winter peak reduction programs. The studies place the greatest emphasis on dynamic rates, such as time-of-use (TOU) and peak time rebate (PTR), which must be implemented by the utility through tariffs and are therefore unsuitable for an all-source procurement.[40] The studies also give a positive recommendation to a residential and small business bring-you-own-

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[38] ASP Report, pp. 13-18. These topics are further explored in John D. Wilson, Mike O'Boyle and Ron Lehr, "Monopsony Behavior in the Power Generation Market," *The Electricity Journal* 33 (2020).

[39] Duke Energy, response to Vote Solar DR-2-17.

[40] Dunsky Energy Consulting, *Duke Energy Winter Peak Demand Reduction Potential Assessment* (December 2020), p. 23.

thermostat (BYOT) program and a non-residential automated demand response (ADR) program.

A BYOT program pays customers an annual incentive to "allow direct response signals to adjust their smart thermostat temperature settings…"[41] Although BYOT programs are often offered through third-party DSM aggregators,[42] Duke Energy intends to implement its BYOT program using its own EnergyHub aggregation platform that is already being deployed for summer peak demand response.[43]

Even if Duke Energy was open to a third-party DSM aggregator, BYOT programs may be more suitable for a single-resource procurement process. Like some other types of third-party DSM programs, a BYOT program's operational characteristics may evolve as development occurs between the contract award and the delivery date. Also like some other third-party DSM programs, BYOT programs are also likely to require negotiation of proposal-specific measurement and verification methods. Programs with these characteristics are difficult to directly compare with generation resources during bid evaluation.

Non-residential ADR programs offer more potential for participation in all-source procurement. As explained in one of Duke Energy's studies,

> ADR programs involve a combination of innovative rates, programs and technology solutions where customers may choose from among different options designed to fit their needs. This solution may also apply to medium sized customers. ADR technology solutions typically require that participants have, or install, equipment that can be controlled remotely, such as a building energy management system that automatically adjust equipment operating parameters in response to pricing signals from advanced rates, such as critical peak pricing or peak time rebate offers.[44]

Presuming that Duke Energy offers effective dynamic rate designs, third-party DSM developers could offer bids to all-source procurement RFPs related to

[41] Tierra Resource Consultants, *Duke Energy Winter Peak Targeted DSM Plan* (December 2020), p. 41. (Hereafter, "Winter Plan") Provided by Duke Energy in response to Public Staff DR-5-6.

[42] Tierra Resource Consultants, *Duke Energy Winter Peak Analysis and Solution Set* (December 2020), p. 57. (Hereafter, "Winter Solution Set") Provided by Duke Energy in response to Public Staff DR-5-6.

[43] Winter Plan, p. 39.

[44] Winter Solution Set, p. 24.

the installation and control of ADR equipment.[45] One advantage of using third-party DSM developers is that they can specialize in particular market segments (e.g., refrigerated warehouses). Third-party DSM developers can also offer customized combinations of incentives and participation requirements, in comparison to the utility's obligation to make the same offer to each customer.[46] This customized approach may yield different results on a per customer basis, but attract more widespread participation.

As with some other DSM programs, ADR programs may be sufficiently well-understood to be evaluated in comparison with generation resources. Where this report refers to "generation resources," that term is also intended to encompass easily-qualified DSM programs.

Nearer-term emerging technologies

Emerging technologies also require special consideration, when the finance, development, or delivery schedule cannot be reliably guaranteed in the response to the RFP. Offshore wind and SMRs are examples of emerging technology that Duke Energy evaluates in alternative portfolios. While offshore wind is a proven technology, the lack of development experience in North America means that the delivery schedule cannot yet be reliably guaranteed.[47] The development of SMR nuclear plants has not been demonstrated, and cannot be reliably guaranteed at any date.[48] In this IRP, Duke Energy added "SMRs, offshore wind, and pump storage … [to its alternative portfolios] manually after optimization of other resources such as solar, onshore wind, and CCs and CTs."[49]

As Duke Energy develops the capability to evaluate emerging technologies in its planning models, one approach it could take would be to maintain their consideration as generic resources until a developer is able to make a fully qualified RFP response. Even if a technology is not considered for deployment until several years after the all-source procurement period (e.g., 2026-2031), retaining such resources in the model influences the timing and

[45] A complication is existing policies that allow large commercial and industrial customers to opt-out of Duke Energy's DSM programs, which would complicate third-party enrollment of opt-out customers.

[46] Winter Plan, pp. 90-91.

[47] DEC and DEP, Appendix A, p. 178.

[48] DEC and DEP, Appendix A, p. 180.

[49] Duke Energy, response to NCSEA DR-7-3.

selection of other bids. For example, the model may favor offshore wind delivery in 2035 over potential delivery of wind from the Great Plains in 2031, exhibiting a need for the Commission to endorse supportive policies if it wishes Duke Energy to pursue offshore wind resources.

This suggests that when evaluating emerging technologies as generic resources, it may make sense to limit them to alternative portfolios. When submitting candidate portfolios to the Commissions for review, Duke Energy can include one or more portfolios that include generic emerging technologies. If the Commissions are sufficiently convinced of the value and viability of an emerging technology, they may approve bids included in that portfolio. A decision to approve an alternative portfolio would not make a commitment to develop any specific project, but it would place Duke Energy on a procurement path that is optimized around the emerging technology.

How should procurement with other resource development activities be coordinated?

Even though it is termed "all-source procurement," Duke Energy will continue to rely on other resource development activities. Among these activities are evaluation of longer-term emerging technologies, grid investments, and energy efficiency (and related) programs, as well as consideration of existing zero-carbon facilities. In adopting all-source procurement, the Commissions should renew existing coordination mechanisms and may need to develop new practices.

Longer-term emerging technologies

Although nearer-term emerging technologies can be incorporated into an all-source procurement process, longer-term emerging technologies require even greater speculation on performance and cost. Relying on such assumptions in a procurement process can significantly affect near-term procurement decisions, and thus represents a major policy decision.

Duke Energy's discussion of ZELFR and other investments "needed to accelerate CO_2 reductions and sustain a trajectory to the Company's net-zero carbon goal" emphasizes that action is required now in order to complete such a dramatic and essential transformation.[50] The IRP process is an appropriate

[50] DEC and DEP, Ch. 16, p. 131. Duke Energy further states, "achieving an aggressive 70% reduction from the 2005 baseline requires emerging technologies such as battery storage, offshore wind, and SMRs. Other ZELFR technologies such as hydrogen turbines or advanced CCS were not considered in this IRP, but may emerge in the future and, as such, could be considered in future resource plans." Duke Energy, response to NCSEA DR-2-11.

venue for considering actions to reduce uncertainties around these technologies.

Duke Energy identifies uncertainties related to ZELFRs (and related storage technologies), that can be considered in three categories:

- Nearer-term generation resources, whose reliability is likely to be demonstrated in the market within the next decade, as discussed in the previous subsection;
- Grid investment technologies, discussed below; and
- Longer-term generation resources, whose availability depends on innovation.

Where the viability of an emerging technology depends on innovation, that innovation may be driven by production experience. As discussed above, learning rates relate declining costs to production experience. Technologies with high learning rates, such as battery storage, are likely to be nearer-term generation resources if there is already high interest and significant production.

The viability of longer-term emerging technologies with lower learning rates,[51] such as SMRs or hydrogen electrolysers, can be accelerated in several ways. The best understood acceleration method is to drive fundamental changes in key input prices.

For example, a substantial "green hydrogen" fuel supply could meet a number of needs, such as decarbonizing heavy industry and meeting long-term storage needs in a zero-carbon grid.[52] Electrolysers would become more competitive if electricity costs drop significantly,[53] and tax incentives can have much the same effect.[54] As discussed in Appendix C, RethinkX's future scenarios suggest this is a possibility. However, producing just today's hydrogen supply from electricity and water would require "more than the total annual electricity generation of the European Union."[55]

Basic science can also transform fundamental technology, repositioning it as a high learning rate technology. Supportive policy, such as government

[51] Hydrogen Council, *Path to Hydrogen Competitiveness* (January 2020), p. 13.

[52] Hydrogen Council, p. 9.

[53] Hydrogen Council, p. 23.

[54] Duke Energy, response to NCSEA DR-2-7.

[55] International Energy Agency, *The Future of Hydrogen* (June 2019), p. 43.

research and development programs, can increase the prospects for breakthroughs.[56] Nevertheless, such transformations cannot be expected on any timetable, as demonstrated by the decades of research into fusion power.

Because of these substantial obstacles, emerging technologies without demonstrated high learning rates or other fundamental challenges should not be considered in IRP models except as alternative, speculative scenarios. In particular, they should not be included in Duke Energy's bid evaluation modeling as potential resources.

Grid investments

Duke Energy's Integrated System & Operations Planning (ISOP) is intended to optimize investments in resources such as transmission, distribution, and voltage optimization programs. The capability to expand renewable resources, energy storage, and imported power is closely linked to investment decisions resulting from the ISOP process.[57] Duke Energy's ISOP is still developing enhanced modeling capabilities that may enable more direct coordination in the evaluation of tradeoffs and synergies between grid, generation, and other resource investments.

Investments in some resources, such as energy storage and DSM programs, can help avoid the need for grid investments. Conversely, grid investments can open up grid access to cost-effective generation resources. This is particularly true for transmission-constrained resources such as imported power and offshore wind. One method for reducing Duke Energy's cost risk associated with transmission-constrained resources could be joining a regional organized power market.[58]

Duke Energy currently plans to integrate transmission and pipeline capacity analysis into its review for replacement of coal units.[59] The analysis Duke Energy describes appears to assume that gas plants will be required for replacement, as there is no discussion of how alternative technologies would be assessed.

[56] Duke Energy, response to NCSEA DR-2-7.

[57] DEC and DEP, Ch. 15.

[58] Duke Energy, response to Vote Solar DR-2-24(c).

[59] Duke Energy, response to Public Staff DR-3-34.

Cost forecasts for the necessary grid investments are thus a necessary consideration in all-source procurement bid evaluations. This is an area where market-based pricing cannot replace Duke Energy's internal cost forecasts, since it is generally impractical to pursue an RFP for grid projects that might be needed to support certain potential generation bids. The Commissions should carefully review the basis for proposed grid investments, and ensure that Duke Energy is evaluating alternative investment levels and strategies concurrent with its evaluation of generation resource bids.

Energy efficiency, load management, and demand-side management programs

Energy efficiency (EE), load management, and demand-side management programs are cost-effective resources that help reduce the size of generation resource procurements. It is technically challenging to identify the optimal cost threshold, above which those demand-side resources become too expensive. This presents an economic coordination challenge for utility analysts.

Currently, the primary tool for coordinating generation resources with energy efficiency (EE) resources is the application of avoided costs in cost-effectiveness tests. These methods may also be applied to load management and demand-side management (DSM) programs. As discussed above (see page 21), dynamic rates and residential BYOT programs are recommended as winter peaking resources, but are best delivered through utility tariffs and single-source procurements. The discussion below applies to investment decision-making affecting all of these resources.

Cost-effectiveness evaluation of these programs is supplemented by limited modeling in the IRP, where Duke Energy modeled low, base and high EE portfolios. Although the high EE portfolio was determined to be cost effective, Duke Energy is concerned about "executability risk" and did not include the high EE portfolio in the base case.[60] As of yet, Duke Energy's IRP process has not proven to be an effective driver of EE resource investment decisions.

The use of avoided costs as a tool for coordinating EE program investments with generation resource costs may be challenged by the emergence of clean energy technologies and the adoption of a biennial all-source procurement process. Avoided costs are defined as the utility costs that are avoided due to

[60] DEC and DEP, Appendix A, p. 171.

adoption of EE programs, and include energy (fuel and other variable costs) and capacity (fixed costs, including power plant development).[61] Clean energy technologies, with very low variable costs, are likely to gradually drive down the avoided cost of energy on Duke Energy's system.

As clean energy drives the substitution of "steel-for-fuel," it might be assumed that the avoided cost of capacity would increase. However, the adoption of a biennial all-source procurement process, with contract deliveries extending out as far as 8 or 9 years into the future, could counteract that effect. Since generation resources that have been selected are no longer "avoidable," the forecast cost of committed resources is not normally considered in the evaluation of avoided costs.

Thus, if Duke Energy's IRP base case does not include a resource commitment to all cost-effective energy efficiency, the resulting increase in contracting for clean energy resources could drive down both the avoided cost of energy and the avoided cost of capacity. In turn, this would make EE resources appear less cost-effective in comparison to generation resources than is actually the case.

This problem could be compounded by other mismatches between the evaluation of generation resources and the evaluation of EE resources in the treatment of carbon policy (see page 30). Even though Duke Energy emphasizes its "base case with carbon policy," it is continuing to use the "base case without carbon policy" when determining avoided costs.[62] Together, these issues represent emerging risks to coordinated decision-making between supply and demand side investments.

One way to ensure that the all-source procurement process does not prematurely drive down avoided costs and the cost-effectiveness of energy-efficiency and other existing zero-carbon resources could be to provide for delivery flexibility in contracts resulting from the all-source procurement. This delivery delay could be requested (perhaps for a fee) by Duke Energy in the event that its ***total system need*** declines significantly. In addition to providing flexibility in the event of changes to the load forecast, allowing for delay, and thus avoidance, of costs would result in a more realistic avoided cost of capacity. Consideration of this issue in Commission policy, review of

[61] Avoided costs are also determined for other important regulatory purposes, notably compensating "qualified facilities" that sell renewable energy to Duke Energy under federal and state rate regulation.

[62] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to ORS DR-3-1(d).

RFP documents, and updates to avoided cost methods could help maintain a reasonable coordination between generation and EE procurement activities.

Renewals and upgrades to existing zero-carbon facilities

Renewals and upgrades at existing zero-carbon facilities are a special challenge to an all-source procurement process.[63] In the case of renewals for existing power purchase agreements (PPAs), there is a question of timing. If an existing solar facility wishes to renew at mutually-favorable terms, its renewal may not be well-aligned with the RFP schedule, particularly over the next several years. This may be a particular concern for solar "qualified facility" projects.

A related issue is that some existing suppliers, such as those same solar "qualified facility" projects, may identify a mutually cost-effective opportunity to upgrade their facility to improve performance. For example, a solar project owner might upgrade inverter technology to offer ancillary services, or it might add solar panels or install a battery behind the inverter to improve on-peak production.

Not only suppliers, but also Duke Energy's own generation facilities will require similar evaluations. Duke's existing methods to evaluate the cost-effectiveness of major maintenance to sustain high levels of performance or output may require reconsideration.

To evaluate these opportunities, Duke Energy may need to continue to utilize an avoided cost method. This evaluation method will face the same challenges, with similar resolutions, as the EE programs discussed above.

What should be reviewed in advance?

One of the five best practices identified in the ASP Report is, "Regulators should conduct advance review and approval of procurement assumptions and terms."[64] Resolving technical and policy questions that affect bid evaluation in advance, rather than during approval hearings, can expedite the certification of winning bids. In Colorado, after the utility bid report is submitted to regulators, full evidentiary hearings are not generally required to obtain

[63] Duke Energy's IRPs assume "existing solar contracts expire over the planning horizon they would be replaced with in-kind generation. This could include renewal of existing contracts or replacement of existing contracts with new solar generation." Duke Energy response to Public Staff DR-3-19.

[64] ASP Report, pp. 24-27.

approval for contracts or even utility-owned projects.[65] By narrowing the scope of review, the Commissions can avoid a contested, time-consuming post-evaluation process.

State regulators have met this challenge. As discussed above, New Mexico resolved model bias issues through an exhaustive review in a special proceeding (see page 11). Colorado regulators conducted a thorough IRP process that includes advance review of "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."[66]

The Commissions' responsibility for oversight of modeling methods and assumptions will encompass a significant number of issues that have often been left to Duke Energy's discretion in its IRPs – as long as they were deemed reasonable for planning purposes. For bid evaluation purposes, a higher standard of review should be required. Appendix B summarizes several IRP modeling methods and assumptions and provides examples of how each issue might be resolved during the IRP process. While most are likely to be technical, some will require policy judgement or attention to the process for subjective consideration. The Commissions should develop a list of modeling methods and assumptions that will be resolved in the IRP process and direct Duke Energy to file an initial proposal.

One issue requiring the Commissions' policy judgement is carbon policy. Duke Energy states that its capability to achieve net-zero emissions by 2050 depends in part on its ability obtain policy support from state regulators.[67] Even though Duke Energy emphasizes its "base case with carbon policy," the "base case without carbon policy" will be used to determine RFPs and evaluate bids until the Commissions approves a carbon policy.[68] The Commissions should make an affirmative decision regarding the forecast for carbon policy (see page 11).

[65] ASP Report, p. 37.

[66] ASP Report, p. 35.

[67] Duke Energy, response to Vote Solar DR-2-11.

[68] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to SELC DR-8-5.

Another area requiring attention in the Commissions' final IRP approvals is the use of any "non-price" factors and attributes that require subjective consideration, either in determining whether a bid is qualified or potentially as a post-model evaluation ranking adjustment. For example, the Commissions might direct Duke Energy to consider mitigation of regulatory risks by including the social costs of air pollution with the direct costs of emissions allowances and operating costs of emission control equipment.[69] In the New Mexico proceeding discussed above, legislative direction to consider employment impacts from a coal retirement was a significant factor in selecting a portfolio (see page 11).

In order to build on proven success in conducting all-source procurements, the Commissions should consider directing Duke Energy to incorporate model documents from Colorado in its own all-source RFP materials. Of course, when considering the Colorado model, Duke Energy should also look to its own practices. As discussed above (see page 15), Duke Energy has conducted single-resource procurements, including gas peaking/intermediate contracts and the CPRE process for renewable energy – and I understand that Duke Energy relied on the Colorado model to design the CPRE process.[70]

Using the criteria discussed in the ASP Report and elaborated on throughout this report, the Commissions should encourage Duke Energy to blend familiar, proven practices with further adaptation of the Colorado model to meet the needs of the Carolinas.

How should bids be evaluated?

When the ***total system need*** determination is paired with a robust bid evaluation, the all-source procurement is clearly differentiated from the conventional single resource competitive procurement. As discussed above (see page 8), these two steps enable utilities to

- Obtain price and performance information about generation alternatives directly from the marketplace, and
- Identify unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies.

The use of market pricing to drive the model-based blending of technologies into a portfolio lifts the constraints of the utility's own cost assumptions and the capacity requirements that are required in conventional single-source

[69] Duke Energy, response to Vote Solar DR-2-1.

[70] NERP Report.

RFPs. The additional opportunities made possible in an all-source procurement makes the outcome more robust and benefits customers by driving costs down and reducing the risks of stranded investments.

The ASP Report details how a robust procurement process can deliver these benefits in its a model bid evaluation process.[71] The Commissions should direct Duke Energy (or its independent administrator) to follow that process, as summarized briefly below.

- Screen bids for minimum compliance, and potentially remove less competitive bids from consideration.
- Evaluate the bids using the IRP system planning model, including both capacity optimization and subsequent production cost modeling.[72]
    - If authorized by the Commissions, make off-model adjustments to reflect resource-specific costs and benefits prior to input.
    - Apply the staged process for bid evaluation to facilitate consideration of bids over the 2026-2031 timeframe (see page 19).
    - Use the capacity expansion model to optimize among bids of all technologies.
    - Using model results, create and compare multiple resource portfolios, each composed of multiple bids. The Commissions may identify specific objectives that should be met by alternative portfolios, and Duke Energy may wish to build alternative portfolios reflecting future development of emerging technologies (see page 23).
- Further study portfolio costs using a production cost model. If there are concerns about reliability, further portfolio review in resource adequacy or power flow models may be conducted.
- Summarize evaluation results in a report, with all model data made available for review by regulatory staff and qualified intervenors.

This final bid evaluation report is the culmination of the process. As discussed above (see page 29), technical and policy questions that affect bid evaluation should have been resolved in advance. The bid evaluation report presents evidence that the utility has adhered to the agreed-upon methods and

[71] ASP Report, pp. 31-32.

[72] As shown in Appendix D, Duke Energy's current IRP process uses only production cost modeling. Appendix D, p. 3.

assumptions, and should streamline the approval process, as discussed below (see page 36).

The Commissions should identify any specific objectives that they wish to be included in alternative portfolios in the bid evaluation report. The importance of including alternative portfolios in the bid evaluation report is a practice modeled in Colorado and New Mexico, as discussed in the ASP Report.[73] Examples of alternative portfolios include:

- Utility recommendation
- High jobs / local resource preference[74]
- Compliance with non-binding state carbon reduction goals
- Include specific emerging technologies
- Higher levels of efficiency

Duke Energy's alternative IRP portfolios in its 2020 IRPs is an excellent illustration of this concept. All-source procurement would enhance Duke Energy's portfolios by building them with market data from bid proposals, not generic resources. In their approval of the bid evaluation report, the Commissions' decisions would select among the alternative portfolios, or direct further adjustments.

As discussed above (see page 14), the Commissions may wish to pilot this process in an initial all-source procurement, and then adopt a rule similar to the CPRE rule in North Carolina, also consistent with South Carolina's Act 62. Many of the specific parts of the CPRE rule (NCUC Rule R8-71) already reflect best practices discussed in the ASP Report. Relying on the CPRE experience should help build confidence in a new all-source procurement process.

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[73] ASP Report, pp. 20, 26.

[74] For example, in the New Mexico case study, the state legislature established a preference for generation resources located in the vicinity of a retiring coal plant. ASP Report, p. 41.

How should fairness and objectivity be ensured, especially with respect to a utility's self-build proposals?

The ASP Report recognizes that regulators often allow utilities (and their unregulated affiliates) to participate in their own RFPs, and that regulators have a responsibility to proactively address structural bias and prevent improper self-dealing by utilities.[75] In some cases, regulators (or legislatures) have cited an interest in giving utilities the opportunity to acquire new assets through market procurements in order to avoid "hollowing out rate base."

Among the reasons that it might be in the best interests of a vertically-integrated utility for the utility to self-build generation are the existing control of an optimal site, advantages due to tax or other similar financial circumstances, and special requirements involving a high degree of coordination with a utility-managed grid improvement project. Often an unregulated affiliate is a highly competitive participant in markets across the country, so excluding it could result in a less competitive procurement. The NC Energy Regulation Process found that, "… there is value in diversity of generation ownership. A mixture of third-party ownership and utility rate-based ownership diversifies risk for customers and provides a variety of benefits."[76]

A good example of a situation in which Duke Energy may be the only feasible developer of a project is the ongoing 260 MW upgrade of the Bad Creek Pumped Storage Generating Station. Once the upgrade is completed, Bad Creek will have a capacity of 1,680 MW, continue to shift power from low to high net load hours, and the capability to adjust output to match load variations and help maintain voltage stability.[77] Where Duke Energy already controls an existing site, it is implausible that a third party would be in a position to offer further resource development. Nonetheless, such projects should be proposed in an all-source procurement process and only proceed if selected in a fair bid.

Citing a well-regarded 2008 NARUC report, the ASP Report summarizes five methods that Commissions should use to proactively address structural bias and prevent improper self-dealing by utilities, including:

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[75] ASP Report, pp. 27-28. It may be either the utility itself, or an unregulated affiliate of the utility. Each requires proactive oversight by regulators.

[76] NCERP, p. 6.

[77] DEC and DEP, Ch. 16, p. 147; response to Public Staff DR-17-5(a).

- Involvement of an independent monitor or evaluator;[78]
- Transparent assumptions and analysis in a procurement process (see page 29);
- Detailed information provided to potential bidders;
- Utility codes of conduct to prohibit improper information sharing with utility affiliates;[79]
- Careful disclosure and review of "non-price" factors and attributes, particularly if they may advantage self-build or affiliate bids (see page 31).

As these practices appear to be incorporated into the CPRE process, the Commissions can build on experience by evaluating how effective they have been. In the process of adapting them to an all-source procurement context, any identified shortcomings can be addressed with a renewed commitment to ensuring fairness.

The ASP Report identified several other practices related to maintaining an objective and efficient process, some of which are discussed elsewhere in this report. One practice is that the all-source procurement process needs to have clearly established methods to address unforeseen circumstances. These may include utilization of the independent monitor's judgement, or may require rapid review of a proposed process deviation by the Commissions.

Another way to promote objectivity is to address issues of participation and information access. Providing detailed information to bidders helps drive down the ultimate cost of winning bids. In order to finance projects cost-effectively, project developers need to minimize sources of uncertainty that are viewed as risks by financial institutions. Utility concerns about revealing its maximum willingness-to-pay price should be very limited in a highly competitive procurement process where the competition's pricing isn't known. For this reason, the Commission should not just defer to the utility's claims of confidentiality when establishing reasonable protections for confidential information.

Furthermore, non-bidding stakeholders can have a constructive influence on the objectivity of the process. The Commissions should allow third parties to

[78] The importance of independent oversight is emphasized in the NC *Competitive Procurement Guidance Document*. NCERP, p. 6.

[79] The importance of communications and separation protocols (modeled on CPRE) is emphasized in the NC *Competitive Procurement Guidance Document*. NCERP, p. 6.

participate in decision-making related to finalizing the RFP process and conducting the bid evaluation modeling process to help correct any bias that may exist within the utility's procurement staff. Of course, third parties should not have direct access to bidders' confidential proposals. An example of an area where third party input might be helpful is in determining whether a significant transmission upgrade required to support several competitive proposals should be included in the recommended portfolio, or only offered as an alternative portfolio.

How should portfolios be submitted and approved?

The final step in the model bid evaluation process is for regulators to approve or modify a resource portfolio.[80] Following the best practice based on Colorado's approval process, the Commissions should establish a procedure for approving or modifying a resource portfolio. The procedure should include a request for comments on the bid evaluation report from parties. The procedure should preserve the Commissions' option to conduct a full evidentiary hearing if significant concerns are raised, but should otherwise proceed based on the written record.

The viability of this specific approval process will depend on the Commissions' rules and preferences. If the Commissions conduct a full evidentiary hearing under conventional project certification statutes and rules, some of the benefit of advance review would be lost.

Multi-state approval

A major challenge to implementing a best practice all-source procurement process is the fact that both DEC and DEP operate in two states, and are thus regulated by both the NCUC and the SCPSC. Inconsistent decisions by the Commissions could lead to significant problems. Duke Energy discussed this issue as follows:

> Should the [South Carolina] Commission order a change to the base case in the IRPs that is not consistent with the North Carolina IRPs, it could result in systemic differences in valuations in other dockets.

[80] ASP Report, p. 32. The best practice also notes that, "If the Commission authorized multiple need scenarios, the decision should also explicitly identify the need scenario that it is relying upon." The use of multiple need scenarios to be considered in an RFP is an additional wrinkle discussed in the Colorado case study. ASP Report, p. 35. Multiple need scenarios will complicate the bid evaluation process, but could be useful if there is uncertainty about the feasibility of a retirement schedule due to reliability concerns.

> … NC and SC regulatory bodies have long treated resource planning in a consistent manner, implicitly recognizing the inherent benefits of the large geography and resource diversity enabled by generation in one state serves customers in another, even when faced with policy variations between the states regarding renewable energy (e.g., NC Senate Bill 3 (2007), SC Act 236 (2014), NC House Bill 589 (2017), and SC Act 62 (2019).
>
> To the extent that the utility commissions require different resource plans with different requirements to satisfy such plans, such requirements raise concerns about shared costs and benefits and may ultimately lead to cost shifting from one state to another, or even – if taken to a logical conclusion— a less optimal mix of resources that could ultimately cost customers more.[81]

One path to resolve this challenge could be for the Commissions to hold joint hearings to oversee the all-source procurement process. South Carolina law authorizes such a process.

> SECTION 58-33-420. Joint hearings with agencies from other states; agreements and compacts; joint investigations.
>
> The commission, in the discharge of its duties under this chapter or any other statute, is authorized to hold joint hearings within or without the State and issue joint or concurrent orders in conjunction or concurrence with any official or agency of any other state of the United States, ... The commission may request the Office of Regulatory Staff to make joint investigations with any official board or commission of any state or of the United States.

Joint hearings could be a very effective means of avoiding different requirements. Both Commissions would review the same evidence, and act on the same procedural schedule. Such an approach could minimize the chance that the Commissions would reach substantially different decisions, except where differing state laws directed such outcomes.

However, it is not clear that the NCUC has authority to hold joint hearings with the SCPSC. Under NC General Statute 110.1(c), the Commission may "confer and consult with … comparable agencies of neighboring states … and may participate as it deems useful in any joint boards investigating generating plant sites or the probable need for future generating facilities." Whether this authority would permit the NCUC to join the SCPSC in an joint evidentiary hearing is a matter for legal determination. Nonetheless, collaboration between the two Commissions and their staffs to the extent feasible should reduce the risk of creating different requirements that could be adverse to customer interests.

[81] Duke Energy, response to ORS DR-3-01.

The Commissions should consider what potential joint hearing options are available under existing law, and the NCUC may wish to inform the North Carolina General Assembly if it believes additional authority is required.

Appendix A: Duke Energy RFPs (2012-2020)

RFP	Requirement	Bids	Special Circumstances	Source
2012 DEC Capacity and Energy	700 MW dispatchable, non-peaking capacity and energy.	12 bidders provided multiple proposals. The DEC Lee Steam Station self-build proposal was selected.	Short-listed proposals were ranked utilizing production cost modeling.	DEC 2013 IRP, p. 41.
2014 DEC/DEP Solar	300 MW solar facilities directly interconnected to Duke Energy's retail service areas.	10 bidders provided 23 bids. DEP contracted for 9 projects totaling 283 MW.	Maximum PPA terms of 15 years, preference for turnkey asset projects larger than 20 MW.	DEC 2014 IRP, p. 45; DEP 2015 IRP, p. 80.
2015 DEC/DEP SC Shared Solar DER	5 MW solar facilities (250 kW - 1 MW) located in and directly interconnected to Duke Energy's retail service areas in South Carolina.	Unable to locate this information.	10 year PPA terms.	DEC 2016 IRP, p.57.
2015 DEC/DEP Utility Scale Program	53 MW PPAs for energy, capacity and RECs from 1 – 10 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in South Carolina in accordance with Act 236.	Unable to locate this information.		DEP 2016 IRP, pp. 57-58.
2016 DEC NC REPS Capacity	General RECs to meet REPS compliance	Executed contracts with 3 bidders.		DEC 2018 IRP pp. 24, 233

RFP	Requirement	Bids	Special Circumstances	Source
2017 DEC Wind	500 MW wind projects (minimum 100 MW) for delivered energy, capacity, and associated RECs.	Bids received were not economically valuable enough to pursue.	All types of delivery contracts considered.	DEC 2018 IRP pp. 27, 80
2018 DEC SC Utility Scale DER - Supplement to 2015 SC DER Utility Scale	40 MW PPAs for 1-10 MW solar facilities located in and directly interconnected to DEC's retail service area in South Carolina.	Six bidders provided 10 bids. Ten solar PV bids with only two bid as single axis trackers. Nine of the ten bids were shortlisted with six executing contracts with DEC.	Projects must be PURPA QFs and contract for a 20-year PPA. Must provide all associated renewable attributes, such as Renewable Energy Certificates, to comply with requirements under the South Carolina Distributed Energy Resource Program Act.	Duke Energy, response to SELC DR-8-1.
2018 DEC/DEP CPRE Tranche 1	680 MW CPRE-qualified renewable energy PPAs or facilities, including all renewable attributes, up to 80 MW in size, and interconnected to one of Duke Energy's retail service areas.	78 solar proposals, 4 also included storage 12 projects totaling 521 MW under contract, including 2 with storage		DEC 2020 IRP, Attachment II, pp. 6-7, 10.
2018 DEC/DEP Swine Waste Fueled	110 GWh[1] swine waste fueled biogas, electric power or RECs, with North Carolina REPS geographic constraints.	Seven proposals, two contracts and three under further consideration.		DEC 2018 IRP p. 79
2018 DEP	Near term need for	Ten bidders provided 32	Projects must commence	Duke Energy,

[1] This is a unique procurement since it procured energy, not capacity.

RFP	Requirement	Bids	Special Circumstances	Source
Capacity and Energy Market Solicitation	approximately 2000 MW of firm dispatchable peaking/intermediate capacity and energy resources resulting from expiring traditional purchase power agreements. Proposals must have a minimum capacity of 75 MW.	bids. • Combustion Turbine - 13 bids • Combined Cycle - 14 bids • Hydro- 2 bids • System (mix of resources) - 2 bids Six bids were selected (1-CC, 4-CT, and 1 Hydro). To date, 5 bids (1-CC, 4-CT) have executed contracts	between 2020 and 2023, concluding by 2028. Projects must meet Designated Network Resource requirements.	response to SELC DR-8-1.
2019 DEC/DEP NC Shared PV Solar	40 MW PPAs for 5 kW – 5 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in North Carolina.	No bidder responses No bids selected	Projects must be PURPA QFs and contract for a 20-year PPA.	Duke Energy, response to SELC DR-8-1.
2020 DEC/DEP CPRE Tranche 2	680 MW CPRE-qualified renewable energy PPAs or facilities, including all renewable attributes, up to 80 MW in size, and interconnected to one of Duke Energy's retail service areas.	43 solar proposals, 4 also included storage 12 projects totaling 689 MW selected		DEC 2020 IRP, Attachment II, pp. 7-8, 10.

RFP	Requirement	Bids	Special Circumstances	Source
2020 DEC/DEP DER Tier III - Solar Bids	53 MW asset transfers for 1-10 MW solar facilities located in and directly interconnected to one of Duke Energy's retail service areas in South Carolina in accordance with Act 236.	Four bidders provided 26 bids To date DEC/DEP has not selected any bids to develop, acquire and construct any SC solar facilities pursuant to the company's efforts under Act 236.		Duke Energy, response to SELC DR-8-1.

Abbreviations

CPRE – Competitive Procurement of Renewable Energy
DER – Distributed Energy Resources
PPA – Power Purchase Agreement
RECS – Renewable Energy Credits
REPS – Renewable Energy Portfolio Standard
RFP – Request for Proposals

Appendix B: Advance Resolution of Technical and Policy Issues

To implement the recommended all-source procurement process, the Commissions' responsibility for oversight of modeling methods and assumptions will encompass a significant number of issues that have often been left to Duke Energy's discretion in its IRPs – as long as they were deemed reasonable for planning purposes. For bid evaluation purposes, a higher standard of review should be required.

This appendix summarizes several IRP modeling methods and assumptions and provides examples of how each issue might be resolved during the IRP process. While most issues are likely to be technical, some will require policy judgement or attention to the process for subjective consideration. The scope of this appendix is intended to provide an indication of relevant issues and is thus an *incomplete* list of modeling methods and assumptions that should be resolved in the IRP process.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Resource Assumptions Resource assumptions can vary by supplier or specific project characteristics. Generic assumptions may bias the model away from otherwise preferred technologies.	The following resource assumptions are determined by Duke Energy staff in the Supply Side Data Manual.[3] Cost or price assumptions may be based third-party published date, on confidential and preliminary quotes, or on other sources. • Total plant cost • Plant EPC cost • Plant owner's cost • Land area required • Land lease/ownership costs • Assumed capacity factor • Seasonal maximum load • Seasonal heat rate, at varying load levels • Heat rate degradation factor	For the most part, these values should be provided in bids on a guaranteed basis. There may be limited exceptions (e.g., environmental reagent prices) that could be standardized similar to the fuel price forecast. Duke Energy's assessment of transmission infrastructure costs for each portfolio

[2] Text in this column may be a direct quote or a paraphrase.
[3] Duke Energy, confidential response to Public Staff DR-3-7.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
	• Variable O&M • Fixed O&M • Planned & unplanned outage rates • Book life • Environmental control technologies • Emission rates • Capital schedule for construction costs • Startup time • Ramp rates • Permitting & construction schedule • Water consumption • Environmental reagent usage and price • CHP steam output • Battery storage overbuild/augmentation • Battery storage total cycles • PV inverter loading ratio • PV degradation rate • Pipeline transportation costs (capital, O&M, or contract costs)[4] • Use of firm pipeline transportation or use of oil as backup for gas prices, including length of contract[5] • Transmission capital costs[6]	

[4] Duke Energy response to Public Staff DR-3-26.
[5] Duke Energy response to Public Staff DR-3-26.
[6] Project transmission capital costs are upgrade requirements required to accommodate power delivery. Additional transmission upgrade costs associated with the entire portfolio are discussed in the main body of the report. Duke Energy's transmission cost estimates are highly uncertain and may not usefully distinguish between the portfolios as their certainty is even lower than the "least amount of detail" under cost estimate classification guidelines. DEC and DEP, Chapter 5, p. 55; Duke Energy, response to NCSEA DR-2-25.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Fuel Price Forecast The evaluation of gas-fueled plants will depend on the fuel cost forecast, which should be identical for all such plants unless they are bid with fuel costs included. An unreasonable price forecast could bias the evaluation results.	The fuel price projections for coal and natural gas are constructed internally using market quoted fuel pricing data and IHS Markit Fundamental Fuel pricing data.[7] Natural gas fuel prices are lower for the newest, most efficient units than for older units.[8] Some existing gas CTs have additional pipeline transportation costs that are not assumed for future units.[9]	The Commissions should explicitly approve the fuel price forecast considering forecast alternatives proposed by the parties on their own merits. The Commissions should consider a preference for a forecast produced by an unbiased public source. The fuel pricing advantage for new units should be part of this review process.
Purchased Power Price Forecast The IRP model includes the opportunity to buy power on the short-term bilateral market. An unreasonable price forecast could bias the evaluation results.	Unable to locate this information.	The Commissions should explicitly approve the purchased power price forecast considering forecast alternatives proposed by the parties on their own merits. The Commissions should consider a preference for a forecast produced by an unbiased public source, if available.
CO_2 Allowance Price Forecast As discussed in the report, the Commissions' position on carbon policy is used to design RFPs and evaluate bids.	As discussed in the report, Duke Energy currently uses its "base case without carbon policy" to determine RFPs and evaluate bids.[10] Duke Energy's portfolios that include CO_2 allowance pricing use an internally developed projection based on factors including earliest likely timing of carbon policy legislation, growth rate to achieve de-carbonization levels, and method of CO_2 penalty.[11]	As discussed in the report, the Commissions should make an affirmative decision regarding the forecast for carbon policy.

[7] Duke Energy response to Public Staff DR-3-13.
[8] Duke Energy response to Public Staff DR-20-8.
[9] Duke Energy response to Public Staff DR-20-10.
[10] DEC and DEP, Tables 12-E and 12-F, pp. 100-101; response to SELC DR-8-5.
[11] Duke Energy responses to Public Staff DR-3-13 and NCSEA DR-7-4(a).

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Renewable Interconnection Limit and Related Resource Constraints Model constraints regarding the timing, quantity, and performance specifications of solar resources may result in suboptimal portfolios, unless the constraints are well-justified. Assumed charges may reflect controversial utility views.	Beginning in 2024, DEC and DEP were limited to 300 and 200 MW/year solar interconnections, respectively, and 150 MW/year wind interconnections.[12] In DEP, model selected solar was limited to solar paired with storage due to increasing likelihood of significant curtailment of incremental solar additions. Model selected solar included a Solar Integration Services Charge.[13]	The Commissions should determine if annual solar interconnection limits are necessary. Solar integration charges are approved in the avoided cost docket. RFP-eligible technologies should include "dispatchable" solar[14] which can be more valuable than take-or-pay solar which can only be curtailed.
Battery Storage Modeling The performance and scale of battery storage has the potential to substantially shift future resource procurements.	Standalone battery storage resources were not optimized in competition with other resources in the system planning model.[15] Instead, storage was selected in a later modeling step, apparently by testing replacement of CTs with storage.[16] Benefits such as ancillary services value are restricted to avoiding solar integration charges in when modeled as solar+storage.[17]	The Commissions should require standalone (and hybrid) storage resources to be eligible resources in the IRP. The Commission should require valuation of ancillary services and other grid operation services that can be delivered by battery storage. Additional emerging storage technologies may also merit consideration, as discussed in the report.

[12] Higher limits were used in alternative portfolios D, E, and F. Duke Energy response to NCSEA DR-7-4.
[13] Duke Energy response to Public Staff DR-3-18.
[14] See Energy and Environmental Economics, First Solar, and Tampa Electric Company, "Investigating the Economic Value of Flexible Solar Plant Operation" (October 2018), available at: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf; National Renewable Energy Laboratory, First Solar, and California Independent System Operator, "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant" (March 2017), available at: https://www.nrel.gov/docs/fy17osti/67799.pdf.
[15] DEC and DEP, Chapter 12, p. 90.
[16] DEC and DEP, Appendix A, p. 161; Duke Energy, response to NCSEA DR-7-6.
[17] DEC, DEP and Dominion Energy North Carolina, *Joint Report on Storage Retrofit Stakeholder Meetings*, NCUC Docket No. E-100, Sub 158 (September 16, 2020), p. 15.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Rooftop Solar Forecast The level of rooftop solar including in the IRP affects the ***load+retirement*** need determination, both in terms of the total energy requirement and in terms of the load shape.	The IRP discusses the rooftop solar forecast but does not provide technical details.[18] The rooftop solar forecast is the same in all portfolios.[19]	The Commissions should explicitly approve the rooftop solar forecast and may wish to request alternative portfolios with differing levels of rooftop solar. If the Commissions selected an alternative portfolio, that would exhibit a need for the Commissions to endorse supportive policy.
DSM Program Dispatch Prices and Capacity Benefit DSM programs may be lower cost than peaking resources such as gas CT and battery storage. Inaccurate (or suboptimal) pricing could result in suboptimal modeling. DSM programs vary in their effectiveness in performing on peak and by season.	Price assumptions for DSM program dispatch are confidential. Program-specific prices are based on internally determined benchmarks.[20] DR resources were counted at 100% of their capacity, even though a sensitivity showed that their load carrying capability is less than 100%.[21]	The Commissions should verify that DSM programs reflect either existing practice or reasonable assumptions about future program operations.

[18] DEC and DEP, Appendix C, p. 228.
[19] Duke Energy response to NCSEA DR-7-7
[20] Duke Energy confidential response to Public Staff DR-3-21.
[21] Duke Energy response to Public Staff DR-4-6.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Availability of Gas Pipeline Transportation Capacity Natural gas plants may require firm capacity in order to provide on-peak service. For plants without firm capacity, the utilization of the gas system during peak periods will determine the amount of oil required as a backup fuel.	Duke Energy reports that there is no unsubscribed existing firm natural gas capacity available. Duke intends to rely on new or upgraded capacity to increase its firm natural gas transportation capacity.[22]	The Commission should determine how bids of gas plants that depend on firm pipeline capacity should be reviewed. Options include requiring the bidder to be responsible for securing the capacity in advance and including an approved pipeline adder. An adder would require Duke Energy to obtain the firm capacity. In either case, the gas plant should bear the entire cost of any pipeline upgrades required. To avoid stranded costs, there should be no assumption that future pipeline users will cover any costs.
Resource Adequacy – Extreme Winter Weather The winter load forecast is sensitive to the relationship between cold temperatures and load. If this relationship is misstated, then the system planning model will over or under-procure resources to meet the winter peak load.	Duke Energy uses linear regression on recent historical temperature and load to extrapolate the peaks for extreme peak days. Extreme weather happens infrequently and there are likely temperatures in the last 39 years that were not seen in the five years of recent history.[23]	The Commissions should explicitly approve the method for relating extreme winter weather to loads.
Joint Planning and Balancing While DEC and DEP have a joint dispatch agreement, they file two IRPs because they are regulated as two separate utilities.	DEC and DEP file joint planning scenarios in their IRPs which demonstrate a significant potential to benefit from a unified IRP or merger of balancing areas.[24]	The Commissions should determine whether they wish an all-source procurement to be evaluated on the current basis, or with unified planning or a merger of balancing areas.[25]

[22] Duke Energy response to Public Staff DR-3-32.
[23] Duke Energy response to NCSEA DR-3-3.
[24] DEC and DEP, Appendix A, p. 199.
[25] Duke Energy response to NCSEA DR-4-2.

Issue	Approach Used in Duke Energy IRP[2]	All-Source Procurement Approach
Load Following Reserve Requirement In addition to planning reserves, utilities maintain load following reserves to respond to short-term grid operation requirements. If the load following reserves are contingent on generation technology, then unreasonable methods for determining the requirement could bias the evaluation results.	Operating reserves modeled in Duke Energy's resource adequacy study include a regulation requirement, spinning requirement, non-spinning requirement and additional load following required for intermittent resources. Regulating reserves are used to cover the continuous fast and frequent changes in load and generation that create energy imbalance. Spinning and non-spinning reserves are contingency reserves used to maintain the balance of supply and demand when an unexpected event occurs. Load following reserves are additional reserves included to manage the variability of intermittent resources such as solar.[26]	The Commissions should explicitly approve operating reserve requirements. In cases where the operating reserve requirements are contingent on the performance characteristics of bids, a method for updating the relevant requirements should be explicitly approved.
Effective Load Carrying Capability The ELCC method assesses the contribution of variable and energy-limited resources (e.g., solar and storage) to meet peak demand. Increased use of these resources results in a declining ELCC. A mix of these resources results in a "diversity impact" such that the combined ELCC is greater than the sum of its parts. An incorrect ELCC value can result in too little or too much expectation that the procured resources will be available during periods of peak demand.	The IRP uses ELCC values calculated by Astrape for the 2018 (solar) and 2020 (battery storage) IRPs. The system planning model does not have the ability to calculate the ELCC dynamically depending on cumulative resources. The ELCC is calculated outside the model, presumably in an iterative manner reflecting the level of resources selected in the model.[27]	The Commission should explicitly approve ELCC studies, including their methods and assumptions, and the methods for applying them in the system modeling.

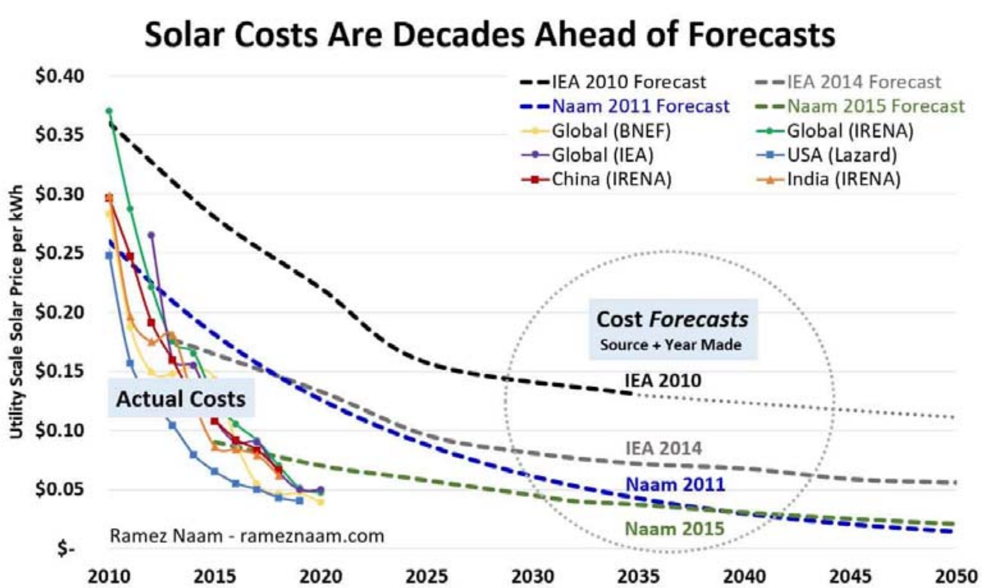
[26] Duke Energy response to NCSEA DR-10-1.
[27] Duke Energy rescponse to NCCEBA DR-3-1.

Appendix C: Advantages of Market Pricing Over Utility Cost Forecasts

Duke Energy's evaluation of the anticipated procurements and the economic retirement dates are outputs of its IRP modeling, which depends on its forecasted cost of new generation. If the forecasted cost of new generation declines, then the economic retirement dates for some plants should advance to an earlier date. Similarly, if new generation costs decline, then it will be cost-effective to advance or increase procurements and reduce the dispatch of existing generation resources. Thus, cost forecasts for new generation resources are a critical input into the need determination.

The problems with cost forecasts are illustrated by the track records of private and government forecasts of solar prices, which have wildly overestimated costs. Rocky Mountain Institute notes that, "in 2010 and 2011, when utilities were expanding coal mining operations and planning to build new coal-fired generating capacity, forecasts suggested 2015–2020 solar PV costs of $100–240/MWh—significantly higher than the anticipated costs of new coal assets at the time."[28] **Figure 1** illustrates that as recently as 2014, the International Energy Agency forecast that the unsubsidized cost of utility-scale solar would remain above 5 cents per kWh through 2050, a barrier that has already been broken, with global and US solar costs (unsubsidized) already below 5 cents per kWh by 2020.

Figure 1: Comparison of solar costs to solar price forecasts



Source: Ramez Naam, "Solar's Future is Insanely Cheap (2020)" (May 2020), https://rameznaam.com/2020/05/14/solars-future-is-insanely-cheap-2020/.

[28] Rocky Mountain Institute, *A Low-Cost Energy Future for Western Cooperatives* (August 2018), p. 5.

The rapidly evolving cost of some technologies, notably solar, wind, and battery storage means that the very foundation of Duke Energy's IRP evaluation is a matter of technology speculation.

In hindsight, technology analysts have shown that clean energy resource costs follow a very "predictable" cost curve. As discussed above, solar costs have declined well below virtually all market price forecasts. So while costs trends were not predicted in key forecasts, the data may now exist to predict these costs.

One technology analysis organization, RethinkX, has published a particularly striking analysis of cost trends for these technologies:

> Cost improvements in solar PV, onshore wind power, and lithium-ion battery technologies have been consistent and predictable for over two decades. Moreover, for solar PV and lithium-ion batteries these improvements have been nothing short of spectacular. The combination of incremental improvements in the underlying technology together with scaling of manufacturing creates a strong correlation between unit cost and production volume, as is common across technologies of many kinds. Solar PV, onshore wind power, and lithium-ion batteries are thus each tracing their own experience curve.[29]

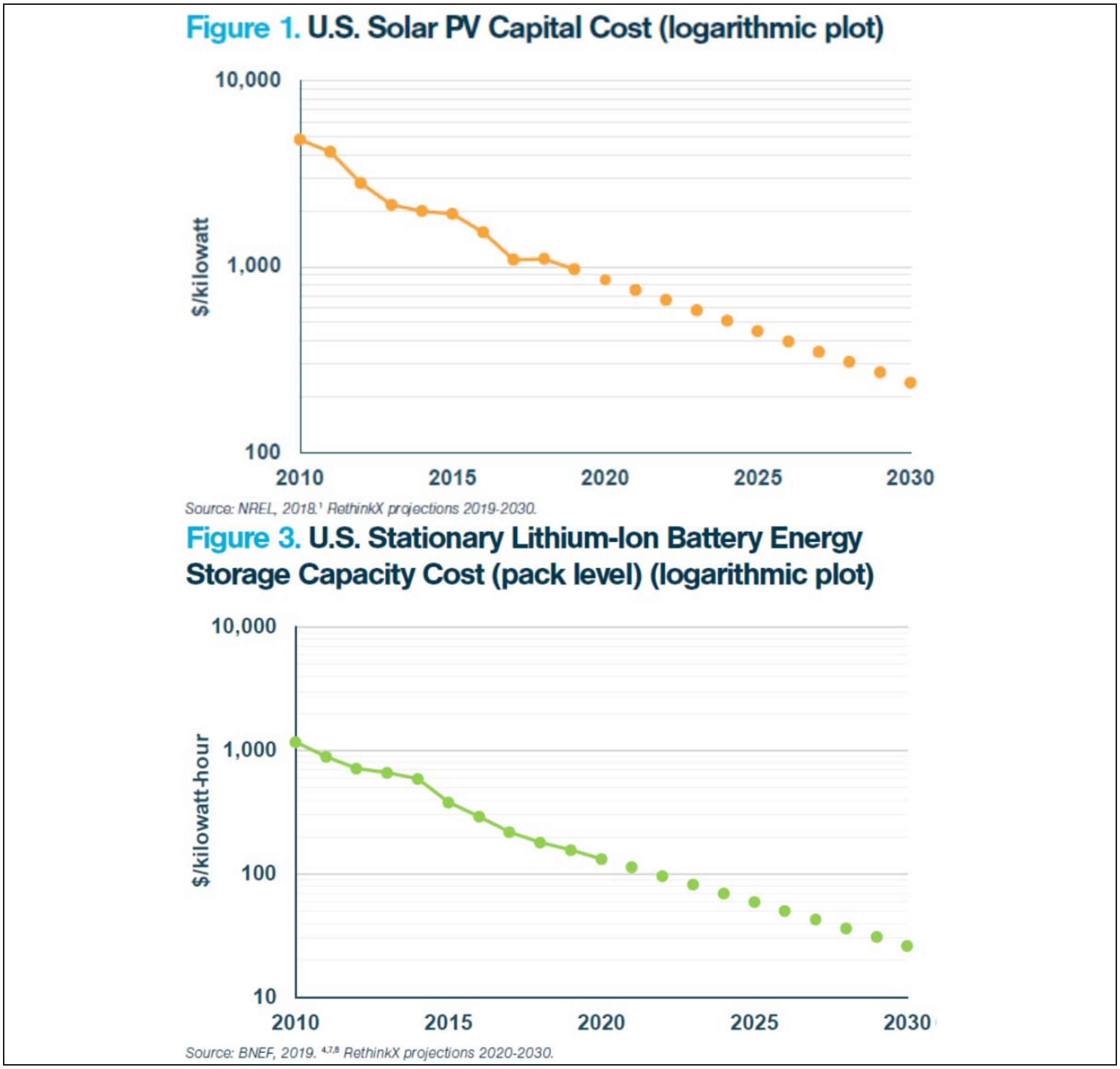
The "experience curve" described by RethinkX is commonly known as a learning rate, and such correlations have been demonstrated in a wide range of industries. Typically, learning rates demonstrate a correlation between production volume and cost that appears as a logarithmic plot over time.

Notwithstanding this economic tendency, future costs trends will depend on factors that cannot be known with precision. As demonstrated by the history of nuclear power development, production experience is no guarantee of declining costs. Government policy, global demand, resource shortages, and a host of other factors can influence prices and, in turn, production volumes over time.

RethinkX's derivation of the learning rates for solar PV and battery storage are shown in **Figure 2**. From 2020 to 2030, RethinkX projects a further 72% decrease in solar PV costs and an 80% decrease in battery storage costs.[30]

[29] Adam Dorr and Tony Seba, *Rethinking Energy 2020-2030*, RethinkX (October 2020), p. 15. (Hereafter, "RethinkX")
[30] RethinkX, p. 8.

Figure 2: RethinkX Forecast of Solar and Battery Storage Costs



RethinkX, p. 15.

In comparison to RethinkX's striking forecast of steadily declining clean energy prices, Duke Energy's forecast anticipates more gradual changes, as shown in **Table 1**. If the cost reductions are similar to the RethinkX forecast, 2030 costs for the listed resource types would be 40% to 64% of Duke's projections.

Table 1: Duke Energy and RethinkX Forecast Costs, 2020–2030

	Cost Change, 2020–2030		Ratio of 2030 Cost
	RethinkX	Duke Energy	RethinkX ÷ Duke
	a	*b*	*c*
Solar	- 72%	- 42%	**48%**
Wind	- 43%	- 11%	**64%**
Batteries	- 80%	- 50%	**40%**

Notes:

a. *RethinkX, p. 8*
b. *DEC and DEP, Chs. 1 & 6, pp. 24, 46; confirmed by Confidential Response to NC Public Staff Data Request 17-1.*
c. *(1 + a) ÷ (1 + b)*

<u>This report does not take a position on whether RethinkX or Duke Energy's forecasts are correct, or that one is better than the other.</u> The challenge of validating cost forecasts are illustrated by Duke Energy's statement that market pricing can differ so much from IRP cost forecasts that a comparison "yields little value in planning space."[31] Duke Energy provides several examples of opportunities that may be available in the marketplace, but are not appropriate for planning purposes, including:

- "Market participants will have varying views on the 'terminal value' of a resource after the [fixed finite term of the] contract period which will affect the bid price . .. Conversely, an IRP evaluates technologies over the life of the asset …"
- "For example, an existing large natural gas generator may have sold the majority of its output under a long-term contract allowing it to bid its remaining capacity into a short-term capacity RFP at a discounted price that is not representative [of] a market based price …"
- "An individual solar project may have unique circumstances such as local property tax discounts, unique tax equity partners, stockpiled panels, or other unique supply chain arrangements that may not represent a widely available price appropriate for planning purposes."[32]

Whether due to an erroneous forecast of market prices or to the cumulative effect of advantageous pricing due to "unique circumstances," when Duke Energy's "planning space" fails to represent the marketplace, its IRP forecast of capacity needs will inefficiently blend technologies. Such inefficiencies ultimately drive up costs for Duke Energy's customers.

While costs forecasts are necessary in the IRP in advance of the procurement process, the ASP Report's case studies illustrate how utilities who leverage market pricing data throughout the planning and procurement process benefit by:

[31] Duke Energy, response to SELC DR-8-1(d).
[32] Duke Energy, response to SELC DR-8-1(d).

- Obtaining price and performance information about generation alternatives directly from the marketplace. The PNM all-source procurement received 735 bids – developers are clearly willing to participate in highly competitive procurement.
- Identifying unanticipated opportunities to meet electricity supply challenges more efficiently with a blend of technologies. Xcel Colorado needed to replace 660 MW of coal plants, but was offered over 58,000 MW (nameplate) of generation resources and procured 2,458 MW, representing 1,100 MW of firm capacity.[33]

Lifting the constraints of the utility's own cost assumptions and capacity requirements is a reasonable and prudent approach. It will result in procurements that will more closely reflect the least cost mix of options.

Constraints on capacity requirements arise from the conventional need determination, which relies on the utility's internal cost forecasts. Typically, utilities obtain cost forecasts from vendor relationships and prior self-build experience, which may be outdated or omit information from competitive market suppliers. Relying on internal cost forecasts and then conducting a series of single-technology need determinations with numeric capacity targets would put Duke Energy, or any vertically integrated utility, on a path that is constrained by those forecasts.

Thus, need determinations, which initiate any RFP process, are sensitive to the generation cost forecasts. If battery prices decline by 80%, rather than 50%, Duke Energy's plans for resource procurement will be outdated and misaligned in terms of cost, schedule and price – likely resulting in procuring the "wrong" resources. These problems can be mitigated by obtaining market-based pricing at the exact time that it is needed for evaluation and contract negotiation by Duke Energy, or any other vertically integrated utility. To minimize the impact of generation cost forecasts on the RFP, the ASP Report recommends what this report is referring to as a ***load+retirement*** approach to need determination.

[33] ASP Report, p. 33.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

8-2. RE: Response to Vote Solar 2-31

c. Please identify all practices that DEC or DEP follow when conducting a competitive solicitation. Please note in your response whether those practices have only been followed for the CPRE solicitations, or whether they are followed for all solicitations. For each practice the Companies follow, please also note whether the Companies would obtain pre-approval by either (or both) Commissions or Commission staff, or whether the Companies would submit the practice for review during the resource Certification process. In your response, please consider the following examples of practices, providing a complete list of practices followed by one or both of the Companies.

i. Bid evaluation using comparison of:

1. Prices, without adjustment for other benefits/costs

2. Net pricing, with spreadsheet adjustment for other benefits/costs

3. Modeled net benefits, using capacity, production cost, or resource adequacy models to identify optimal resource(s)

ii. Consideration of interconnection costs

iii. Valuation of ancillary services

iv. Joint evaluation by DEC and DEP of bid results

v. Disclosure of information to bidders such as geographic preferences due to load, transmission capability, etc.

vi. Disclosure of final PPA with all terms and conditions pre-approved by the NCUC or SCPSC (please provide details of the pre-approval process)

vii. Consideration of non-quantitative factors such as viability/experience, permitting issues, etc.

viii. Development of multiple portfolios for final review, if such a practice has been utilized, please identify who conducted the final review of the portfolios (Company staff, executives, Commission staff, Commission, etc.)

ix. Procedures to ensure that the Company or its affiliates compete fairly with other bidders

x. Use of independent evaluator, administrator, etc. (please identify roles)

<u>Response</u>:

The following identifies the practices generally used by Duke Energy to conduct competitive solicitations. The specific practices for each competitive solicitation may vary due to the exact objectives and requirements from regulatory or legislative actions. NC HB 589 requires that the NC CPRE solicitations, including the analysis of the bids and selection of winning bids, are performed independently by a third-party consultant. The Companies have attached to this response the Independent Administrator's Final Report from Tranche 1, which provides an explanation of the analysis performed by Accion. Generally, most regulated utility competitive solicitations follow the same high-level practices (including the NC CPRE solicitation) but can vary in the analysis of bids due to the level of sophistication in methodology selected by the utility or outside consultant. Unless required by statute or by the respective Commission (NCUC or SCPSC), the Companies do not obtain pre-approval by either utility commission for the issuance of the RFP.

CPRE IA - Final
Report Tranche 1.pdf

<u>Duke Energy RFP Process</u>

RFP Design

- Recognize the resource need and specific requirements for an RFP as directed from the filed Integrated Resource Plan.
- Determine applicable resource types including traditional, renewable, and/or Distributed Energy Resource (storage) generation resources, the need for peaking vs. baseload operations, and dispatchable vs. non-dispatchable requirements.
- Determine applicable RFP contract structures including but not limited to Purchase Power Agreements ("PPA"), Build-Own-Transfer arrangements ("BOT") and existing Asset Purchases ("AP").
- Determine applicable delivery points including preferred locations (Balancing Areas), transmission firmness/interconnection requirements and general deliverability requirements.
- Determine applicable quantitative and qualitative bid characteristics (with relative importance) that will be considered during project analysis and selection.
- Determine targeted RFP participants including considerations of affiliates that may require an independent third party to oversee the RFP process.
- Create RFP solicitation and term sheets including applicable IRP, resource, and contract specifications with a primary goal of clearly defining the product being requested. The RFP document should provide an overall transparent description of analysis methodology, timelines, bidder response requirements, and all value metrics to be considered.
- Review RFP as appropriate with stakeholders.
- Release RFP to marketplace with specific dates for notice of intent to bid (NOIB), RFP milestone schedule, and proposal submission details.

RFP Analysis

- Receive proposals using applicable confidential/firewall separations as appropriate with regulators and utility standards.

- Review submitted proposals for compliance with RFP specifications

a. **Dispatchable Proposal Analysis**

i. Perform initial static cost screening

1. Fuel commodity and transportation costs are developed.
2. Assume capacity factor and starts based on production cost modeling experience to determine all operational energy costs.
3. Determine all applicable costs including wheeling, interconnection, capacity, fixed and variable O&M, fuel.
4. Summarize all calculated costs and rank proposals using annual levelized $/kw costs
5. Identify most cost-effective proposals from screening to proceed forward to more detailed production costing modeling

ii. Perform more detailed production costing modeling for highest ranked proposals.

1. All operational proposal characteristics modeled in detailed production simulation energy models.
2. Calculated model energy values netted against fixed costs (Wheeling, FT, Capacity Fees, FOM) to determine net levelized $/kw annual cost
3. Rank proposals on a net levelized $/kw cost basis.
4. Quantitative and qualitative results for each proposal are summed and ranked for short list proposal selection
5. Highest ranked bids modeled in alternative portfolios and scenarios (using ranges of fuel costs, loads, and environmental costs) to determine most robust portfolio selections.
6. Short listed proposals identified, and contractual negotiations are initiated.

b. **Non-Dispatchable Proposal Analysis**

1. Transmission wheeling charges determined and added to proposal cost.
2. Non-dispatchable hourly generation profiles are used to develop energy benefits using hourly power market curves and/or marginal/avoided hourly costs.
3. Capacity benefits are calculated using non-dispatchable hourly energy profiles consistent with utility capacity needs.
4. REC benefits are given when appropriate.
5. Benefits (energy, capacity, ancillary) are netted against costs (wheeling, interconnection, fixed, ancillary) to develop annual “net costs” for bid term/project life.
6. Net costs are levelized on a $/mwh basis and ranked for comparison.
7. Quantitative and qualitative results for each proposal summed and ranked for short list proposal selection.
8. Most cost-effective bids modeled in alternative proposal portfolios and scenarios to determine most robust proposal selections.
9. Short listed proposals commence contractual negotiations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[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.

[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.

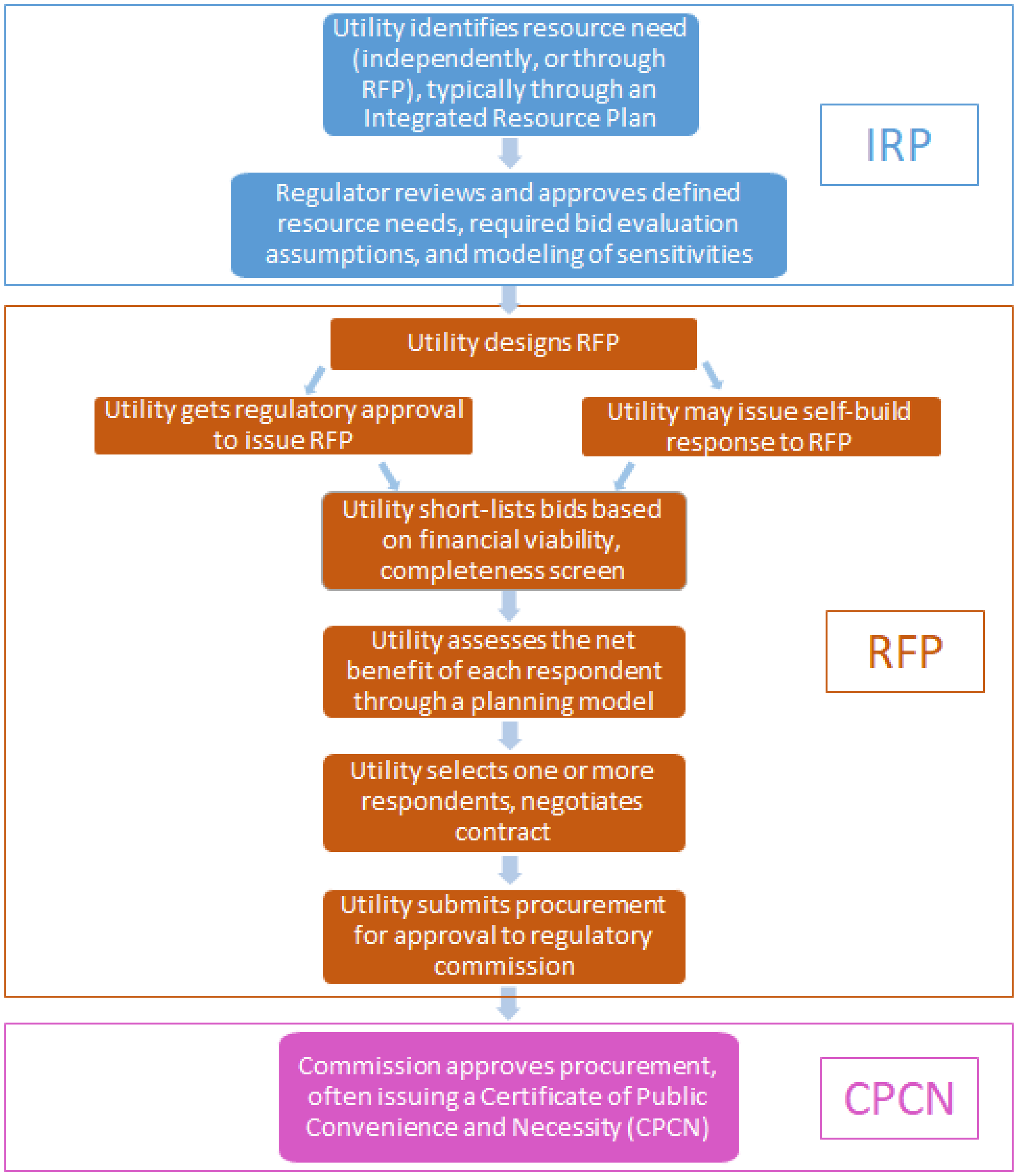
In states with traditional, or partially restructured, bilateral wholesale markets,[12] IRPs typically lead to discrete resource approvals through a certificate of public convenience and necessity (CPCN). Often, regulators require utilities to issue an RFP as part of that process. Regulators practice 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.

[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 PROCUREMENT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Some utilities offer little transparency.

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

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

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

MODEL PROCESS FOR BID EVALUATION

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

   i. Select an independent evaluator.

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

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

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

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

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

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

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

e. Results of evaluations should be summarized in a report, with all model evaluation data made available for review by regulatory staff and qualified intervenors. The independent evaluator's report should be included.

f. After soliciting comments on the bid evaluation report from parties, regulators should approve or modify a resource portfolio. If the Commission authorized multiple need scenarios, the decision should also explicitly identify the need scenario that it is relying upon.

CONCLUSIONS

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

ACKNOWLEDGEMENTS

The authors gratefully acknowledge comments and contributions from the following individuals (organization for identification purposes only): Jim Caldwell (CEERT), Jeff Ackermann (Colorado PUC), Anna Sommer and Chelsea Hotaling (Energy Futures Group), Eric Gimon (consultant to Energy Innovation), Jamie Barber (Georgia PSC), Ric O'Connell and Taylor McNair (GridLab), Rob Gramlich (Grid Strategies), David Farnesworth, John Shenot and Jessica Shipley (Regulatory Assistance Project), Lauren Shwisberg (Rocky Mountain Institute), Jeremy Fisher (Sierra Club), Simon Mahan (Southern Renewable Energy Association), and staff at Energy Innovation, Resource Insight, and Southern Alliance for Clean Energy.

[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

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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]

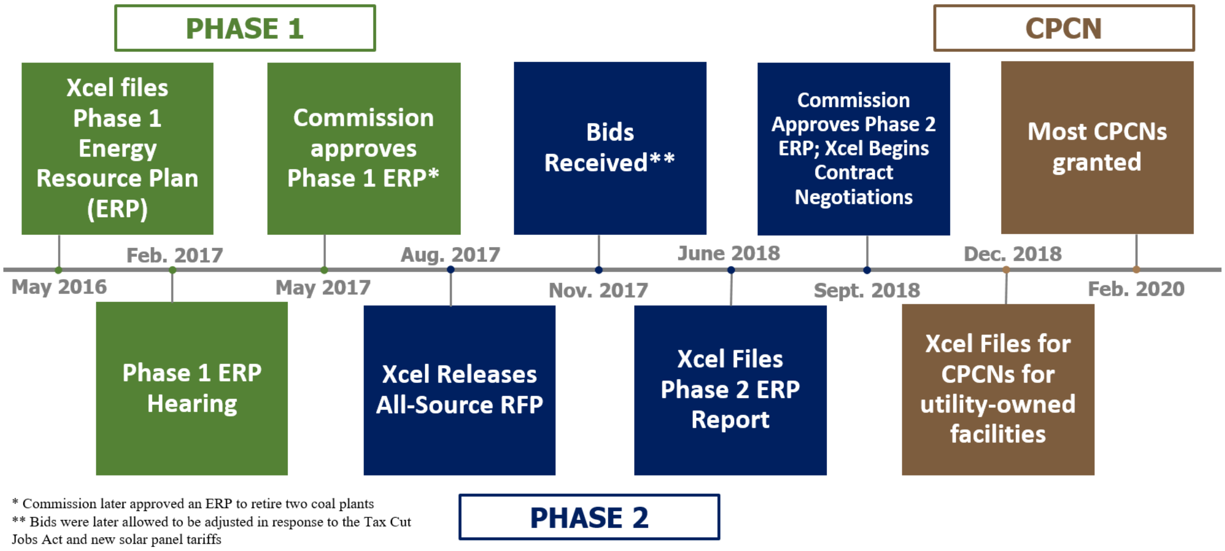
All bids that are forwarded to modeling are modeled together[26] under the assumptions approved in Phase 1. The rules ensure that the utility's portfolio development phase will include a sufficient quantity of bids across various generation resource types such that alternative resource plans can be created.

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.

[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).

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

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[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).

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