STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's 2023 Integrated Resource Plan Update, Application for Certification of Plant Yates Units 8-10	))))))	Docket No. 55378

DIRECT TESTIMONY AND EXHIBITS

OF ALBERT LIN

ON BEHALF OF

SIERRA CLUB AND

SOUTHERN ALLIANCE FOR CLEAN ENERGY

June 21, 2024

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.

A. My name is Albert Lin. I am an economic and financial consultant located at 26732 Via La Jolla, San Juan Capistrano, CA 92675.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the Sierra Club ("SC") and the Southern Alliance for Clean Energy ("SACE").

Q. PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE, AND EDUCATIONAL BACKGROUND.

A. I have worked in the financial analysis and the capital markets since 1989. Directly after graduating from the University of Texas at Austin with a Bachelor of Science in Finance, Bachelor of Arts in International Business, and an Honors Business Master's degrees, I worked for a regulated utility called General Telephone and Electric ("GTE", now called Verizon). GTE conducted business in over 20 different states in the United States with most of the company's revenue derived from regulated activities approved by Public Utility Commissions ("PUCs") or a similar governmental body in each State GTE conducted business in. My roles were in the finance and audit departments where I analyzed and supported optimal financial outcomes for shareholders within the policies and orders of each respective State's PUC. I mostly worked on financial and accounting activities which would likely achieve the highest financial returns possible with least operating risk and variability of outcomes for GTE's equity shareholders. These roles would include

satisfying credit rating agencies that may impact the cost of debt for GTE, which would likely also affect how shareholders perceived the equity value.

After a series of legislative changes culminating in the Telecommunications Act of 1996, the primary activities for GTE were fully de-regulated across the country. Just prior to the passing of the Telecommunications Act of 1996, my work focus shifted to the equity valuation of wireless communications assets, pricing the cost of capital and equity value of wireless communication assets, working with various Wall Street capital markets firms, plus being a founder partner for a FINRA (Financial Industry Regulatory Authority) registered broker-dealer which focused on equity valuation and forecasts in high-growth industries such as the technology industry sector.

Starting in 2012, I served as CEO and Chairperson of the Board of EmberClear Corporation, during which the Company developed, permitted, and sold to Ares Capital and ITOCHU Power & Environmental Services three natural gas combined cycle plants and a zero-emissions IGCC with carbon dioxide sequestration or re-use plants of 300 – 450 Megawatts of nameplate capacity.

From 2020 to the present, I have been focused on economic and financial analysis supporting the energy industry. This includes the regulated electricity sector of the United States. A copy of my professional resume, which includes my employment history and education, is attached as **Exhibit AL-1** to this testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide perspectives and offer recommendations after reviewing the filings related to Docket 55378 in the matter of Georgia Power's Application for the Certification of four advance frame, dual-fuel simple cycle combustion turbines ("Yates CTs").

Q. WHAT INFORMATION DID YOU REVIEW TO PREPARE YOUR TESTIMONY?

A. I reviewed Georgia Power's application, witness testimony, and discovery in this case, along with relevant Georgia law and a variety of documents from other Commission proceedings. My testimony is also informed by my experience and work in the utility and financial sector and by industry publications, discussed in greater detail below.

Q. PLEASE SUMMARIZE YOUR KEY RECOMMENDATIONS FOR THE COMMISSION.

A. My conclusions and recommendations are as follows:

I recommend a delay in certification to provide additional time to create an updated policy on how the Fuel Cost Recovery (FCR) policy is implemented in Georgia. This FCR update is even more important for new construction as the useful life of such assets are often greater than 25 years. The moral hazard[1] inherent

[1] *See* p. 10-11 below for details on the term "moral hazard."

with the current Fuel Adjustment Clause (FAC) creates a large and growing financial risk to customers of Georgia Power since 100% of fuel costs are passed through to customers. Approval of the Yates CT application on an expedited timeline is especially problematic given the GPC's increasing reliance on natural gas for baseload generation and the utility's lack of firm supply for the proposed units. Additionally, GPC did not explicitly model the proposed Section 111d rules into its 2023 IRP Update.[2] It is critical that the GPC factor these environmental compliance costs into the proposed project. Since technologies for electricity generation have changed and evolved over time, it is only fair to evaluate total system costs and risks no matter who eventually pays for it.

This additional time would also allow GPC to undertake a technology neutral all-source power procurement process. While time may be of the essence, it is also sensible to ensure that all possible options to serve anticipated load growth have been adequately examined and analyzed including the Yates CTs. The US Department of Energy Grid Modernization Initiative sponsored a report published by the Lawrence Berkely National Laboratory identifying the benefits of an all-source competitive solicitation, attached as **Exhibit AL-2**.[3] Since there is an All Source RFP currently underway, the timing is ideal to include all the loads and sources--including the Yates CTs-related portions--into that process to find the best choice for customers over the long-term.

[2] *See* GPC Response to STF-PIA-7-4.
[3] *See also* Direct Testimony of Ronald J. Benz, Exhibit 3, Docket 44160.

II. BACKGROUND ON UTILITY FUEL COST RECOVERY (FCR)

Q. WHAT IS GEORGIA'S FUEL COST RECOVERY LAW?

A. Georgia law requires a public hearing on each electric utility's FCR proposal, which is to be held no less than ten days after the utility's filing. O.C.G.A. § 46-2-26(d). Not later than 90 days after the utility's filing, the Commission must issue an order that states the base fuel rates to be used by the utility during the next three consecutive calendar months, or until changed as provided in law. O.C.G.A. § 46-2-26(e). The Official Code of Georgia Annotated Section 46-2-26(a)(1) defines "fuel costs" as the cost of fuel "as defined in the utility company's tariffs in effect on July 1, 1979[.]"

Q. HAVE THERE BEEN MATERIAL CHANGES WHICH AFFECT THE IMPLEMENTATION OF THE FCR SINCE 1979?

A. Technology used for the generation, management, and conservation of electricity has changed and evolved materially since 1979. This certification process mostly focuses on generation of electricity with the construction of assets used to produce electricity. In 1979 virtually all technologies used to generate electricity required some type of fuel. Today, various forms of technology require little or no fuel. For example, technologies for generation based on hydro, solar, and wind require low to no fuel cost to generate electricity.

Q. WOULD A CHANGE IN STATUE BE REQUIRED TO UPDATE THE FUEL COST PRACTICES IN GEORGIA?

A. No. The statute O.C.G.A. § 46-2-26 grants the Georgia Commission sufficient flexibility to adjust the risk- and cost-sharing ratios of the Fuel Cost Recovery

mechanism. While the statute mandates utilities propose base rate tariffs to recover fuel costs, it does not obligate or entitle recovery of all fuel costs. The Commission is not required to approve tariffs that contain full recovery of fuel costs, permitting the Commission to have utilities share in fuel cost risks with customers. Historical dockets, such as 19142-U and 11884-U, demonstrate the Commission's practice of modifying proposed tariffs, indicating broad discretion to ensure utilities share in cost responsibilities to promote proper allocation of assets where the operating cost risks are reasonable and optimized.

Q. CAN YOU QUANTIFY HOW SUCH CHANGES IN TECHNOLOGY ARE RELEVANT FOR GEORGIA POWER?

A. Georgia Power is the largest electricity subsidiary of three which are part of the parent holding company, Southern Company. For 2024, Georgia Power is expected to consume 66% of the capital investment of Southern Company. For year-end 2023, Southern Company had 4.4 million customers with 61% (2.7 million) in Georgia Power territory.[4]

Southern Company categorizes renewables within their "other" category, which comprises technologies for generation using wind, solar, hydro, biomass, land fill gas, and fuel cells. Using Southern Company's data, Renewables/Other grew from 1% of annual energy generation mix in 2007 to 14% over a 16-year time

[4] Southern Company, Fourth Quarter 2023 Earnings Conference Call Presentation (Feb. 15, 2024), p. 18, available at: https://s27.q4cdn.com/273397814/files/doc_financials/2023/q4/SO-2023-Q4-Earnings-Call-vF-2.pdf.

period ending in 2023.[5] Looking at Southern Company data for very low and no fuel technologies of just hydro, solar, wind, and battery storage, the current plan calls for approximately 400% growth in those sources from less than 5 GWs in 2015 to over 20 GWs by 2030 (a 15-year time frame).[6] With expectations for ongoing and possibly accelerating growth in new technologies taking place over the last 16 years and anticipated for the next 7 years, there is an increasing need to implement policies that reflect these changes in the marketplace.

Q. WHAT WOULD HAPPEN IF THE FUEL COST RECOVERY POLICIES DO NOT REFLECT A CHANGING WORLD?

A. When a system exists where some technologies benefit from an FCR and other technologies do not, such asymmetries run the risk of producing poor economic and commercial choices where the cost and risk of major investments will not be evaluated correctly. In order to serve the public interest, the Commission is obligated to create the proper incentives so that major risks to the cost of the electricity market is optimized by the parties who have the information and power to make those decisions. For example, items which have a fuel cost may appear to

[5] *Id*. at 36. Southern Company adds generation of renewables from affiliates in their computation. Annual energy mix represents all of the energy the Southern Company system uses to serve its retail and wholesale customers during the year. It is not meant to represent delivered energy mix to any particular retail customer or class of customers. Annual energy mix percentages include non-affiliate power purchase agreements; Renewables/Other category includes wind, solar, hydro, biomass, landfill gas and fuel cells.
[6] *Id*. at 38. This includes owned and contracted resources including 100% capacity for jointly owned projects. With respect to renewable generation and associated renewable energy credits (RECs), to the extent an affiliate of Southern Company has the right to the RECs associated with renewable energy it generates or purchases, it retains the right to sell the energy and RECs, either bundled or separately, to retail customers or third parties. Future estimates include owned and contracted capacity that have received regulatory approval. Additional renewable resources could be added prior to 2030 at Southern Power or at the traditional electric operating companies, should they be proposed and approved through regulatory processes.

have no fuel cost during a financial analysis if the actual cost of fuel is passed on to another party not directly related to the party performing the analysis.

Q. EXPLAIN HOW SUCH AN ECONOMIC OUTCOME MAY OCCUR.

A. The largest single operating cost associated with mainstream technologies such as thermal coal, natural gas, and diesel, is often the fuel. With an FCR, the fuel cost is passed through to another party such as the customer. This makes the financial modeling of the cost of such technologies appear as if they are equivalent to a low or no fuel cost technology from the perspective of the utility. The utility's ability to purchase fuel and pass the cost to another party also impacts the competitive marketplace where other users (such as commercial, industrial, and the natural gas utility) must compete against a price insensitive competitor operating under an FCR buying the same fuel in the market.

Q. IS THIS A NEW PHENOMENON?

A. In the regulated utility industry, this phenomenon has only recently become a topic of regular discussion driven by the growing percentage of the system using low or no fuel technologies combined with the growth of the overall electricity system which is creating greater demand for fuels. The impacts of fuel cost and fuel price volatility were easier to ignore when the absolute dollars involved were smaller and the availability of low or no fuel options were low. Outside of the regulated utility industry, the economic and risk trade off described previously is termed "moral

hazard" and has been an economic term used in the insurance industry for centuries.[7]

Q. WHAT DOES THE TERM MORAL HAZARD MEAN AND HOW DOES IT APPLY TO THIS CERTIFICATION PROCESS?

A. Moral hazard occurs when a party takes on additional risks because they are not required to bear the full consequences of those risks. Imagine you are able to build a home on the banks of a river. If there were a zero cost no deductible insurance policy offered, it would likely create artificially high demand for such properties as people seek the benefits and value of such a property knowing the costs for a possible flood would be borne by another party. This change in behavior from simply knowing someone else will cover the financial consequences is what the industry calls moral hazard. Moral hazard often occurs in situations where an imbalance exists regarding who bears the cost of risky actions, leading to potentially riskier behavior. For the Commission's purposes, moral hazard is mostly focused on the risk to customers for fuel costs to operate the Yates generation assets once constructed. With an FCR that shifts the largest operating cost item to another party, the utility may be increasing the financial cost to the electricity system's customers whether intentionally or unintentionally by spending less time fully evaluating all options thereby leaving the customers to absorb the price volatility and total fuel cost.

[7] *See* Cassandra Jones Harvard, "What does 'moral hazard' mean?," *University of South Carolina* (March 21, 2023), available at: https://sc.edu/uofsc/posts/2023/03/conversation_moral_hazard.php#:~:text=The%20concept%20describes%20financial%20recklessness,have%20taken%20without%20that%20coverage.

Q. IF THE MORAL HAZARD DIDN'T EXIST, WHAT WOULD BE DIFFERENT?

A. The existing FCR almost forces the utility to avoid the cost and time of analyzing factors impacting cost and price volatility for fuel as such efforts would not impact the financial outcome for the shareholders. If the utility had a financial stake or "skin in the game" tied to the outcome of fuel costs, I believe the utility would pay closer attention to economic and financial factors other business entities consider when examining a large operating cost. Specifically, the utility would examine 1) options to manage fuel cost with a focus on fuel price volatility risks and 2) analysis on the key components of supply and demand which may have a large financial impact on the cost of generating electricity.

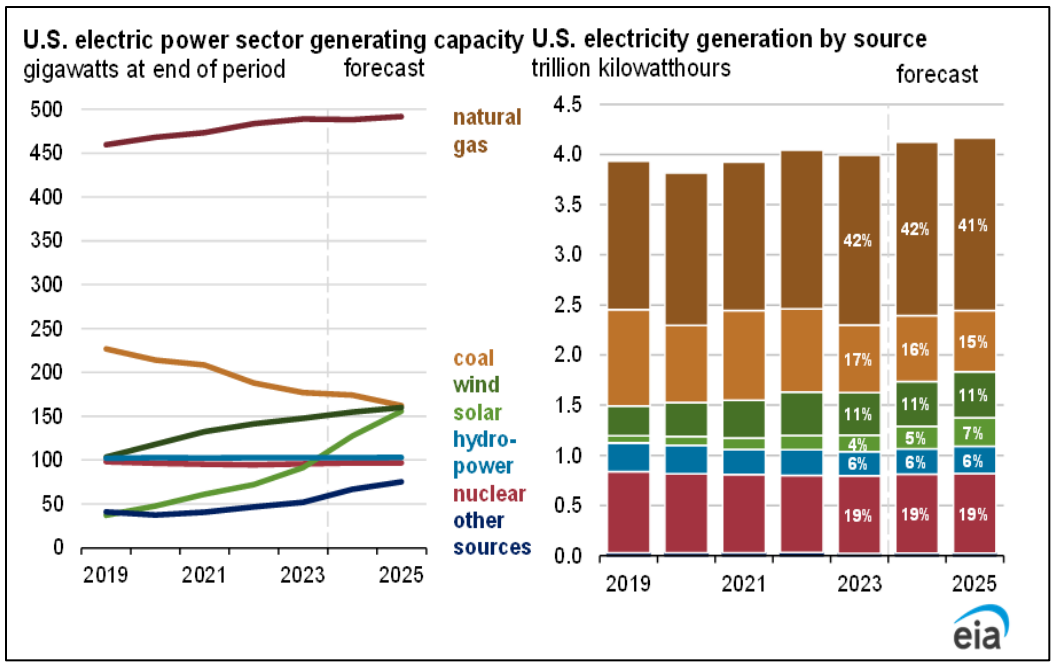
Q. WHAT TECHNOLOGIES APPEAR TO HAVE LARGE FINANCIAL RISKS WITH REGARDS TO FUEL COST?

A. In the current market, natural gas-based technologies have the highest economic risk due to systemic overreliance on the technology, extreme price volatility, and lack of ability to forecast future prices. Coal fueled technologies would be a distant second since prices are usually set with multi-year contracts with more moderate escalators and adjustments during the life of the contract.

Q. ARE YOU ABLE TO QUANTIFY THE POINT YOU MAKE FOR NATURAL GAS OVERRELIANCE?

A. The US Department of Energy's Energy Information Administration (EIA) tracks and forecasts the technologies used for electricity generation. The two charts below illustrate how natural gas has grown disproportionately, representing 42% of the market in 2023.

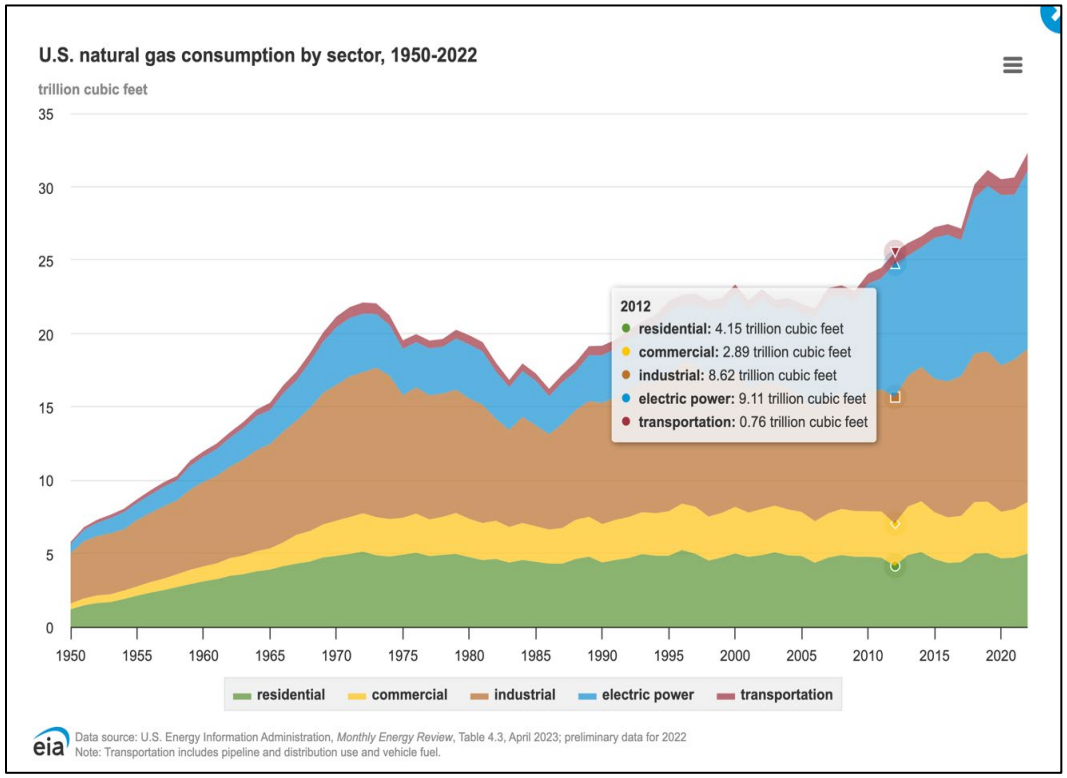
Figure 1: US electric power sector generating capacity US electricity generation by source



Source: US Department of Energy, Energy Information Administration, available at: https://www.eia.gov/outlooks/steo/images/Fig30.png.

The production of electricity using natural gas was insignificant to moderate until recently. The rapid growth starting around 2005 has resulted in the electric production category becoming the top customer for the natural gas industry.

Figure 2: US natural gas consumption by sector, 1950-2022

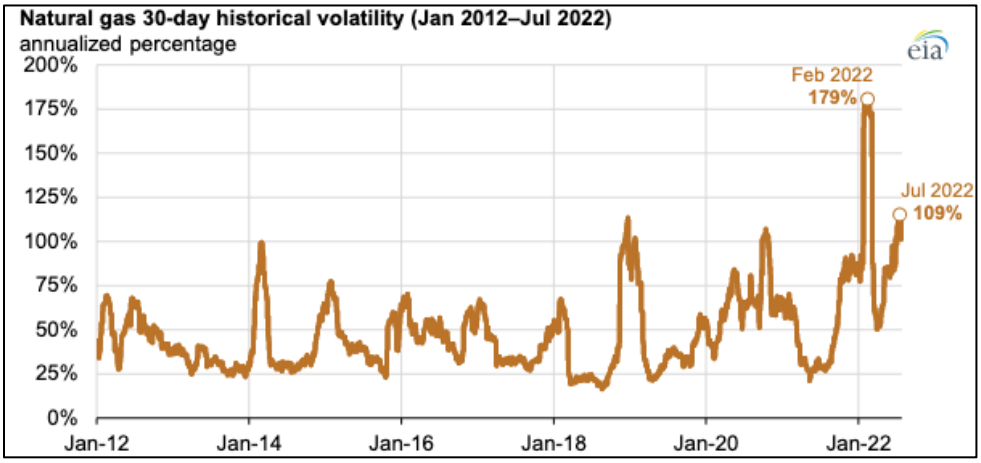


Source: US Department of Energy, Energy Information Administration, "Natural gas explained" (last updated April 28, 2023), available at: https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

Q. PLEASE DESCRIBE THE EXTREME PRICE VOLATILITY OF NATURAL GAS.

A. The EIA has noted natural gas price volatility is not only exceedingly high, but also found the trend for volatility has been increasing and hit an all-time high in 2022 according to a report published August 24, 2022.

Figure 3: Natural gas 30-day historical volatility (Jan 2012-July 2022)



Source: US Department of Energy, Energy Information Administration, "U.S. natural gas price saw record volatility in the first quarter of 2022" (August 24, 2022) available at: https://www.eia.gov/todayinenergy/detail.php?id=53579.

The recent large moves in 2022 were preceded by many points in time of extreme price volatility including five (5) incidents where prices moved by over 100%. It's worth noting that the data in the EIA study is using a 30-day average price. The actual price of natural gas varies far greater when measured by shorter period (days, for example). Price volatility for natural gas is so extreme that even very large un-regulated markets have been forced to place price caps on the wholesale price of electricity twice. Industry publication Natural Gas World further highlighted the extreme natural gas price volatility in their January 2023 report, noting new record levels of natural gas price volatility, specifically that monthly actual (not implied) price volatility for the preceding 5 years (2017-2021) was 47.2% and the single year 2022 monthly price volatility was 92.7%.[8] If the electric utility is designed to be a safe and conservative industry with a premium on reliability, it will become harder to maintain and achieve that goal when becoming more reliant on a

[8] Natural Gas World, "US natgas price volatility hit record highs in 2022" (Jan. 3, 2023), available at: https://www.naturalgasworld.com/u.s.-natgas-price-volatility-hit-record-highs-in-2022-102971.

commodity which sees prices change 47.2% each month. The Texas PUC reduced the HCAP (High Systemwide Offer Cap) to $5,000/MWh from $9,000/MWh in January 2022 after a multi-day storm caused system service failures and severe financial duress for those who had to purchase power at $9,000/MWh for multiple days.[9] Texas is the largest producer and consumer of natural gas.[10] Yet, even the size and depth of the Texas market could not economically serve the electricity sector.

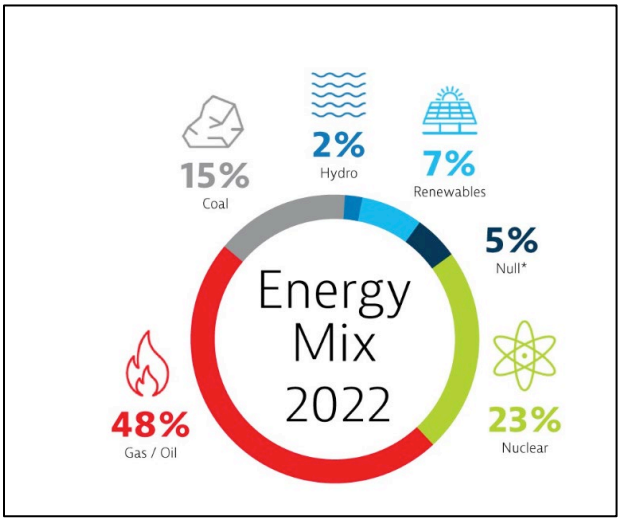
Q. WHAT DOES NATURAL GAS PRICE VOLATILITY MEAN TO SOUTHERN COMPANY?

A. In 2022, 48% of Georgia Power's energy mix was natural gas/oil dependent.

[9] Connor Madden, "The ERCOT Market's Cap and the Power Grid's Long Winter's Nap: Recommended Improvements to Texas's System-Wide Price-Capping Methodology," *Texas Law Review* Vol. 101 No. 3, available at: https://texaslawreview.org/the-ercot-markets-cap-and-the-power-grids-long-winters-nap-recommended-improvements-to-texass-system-wide-price-capping-methodology/#:~:text=As%20previously%20mentioned%2C%20not%20long,MWh%20down%20to%20%245%2C000%2FMWh.

[10] US Department of Energy, Energy Information Administration, "Which states consume and produce the most natural gas?," available at: https://www.eia.gov/tools/faqs/faq.php?id=46&t=8.

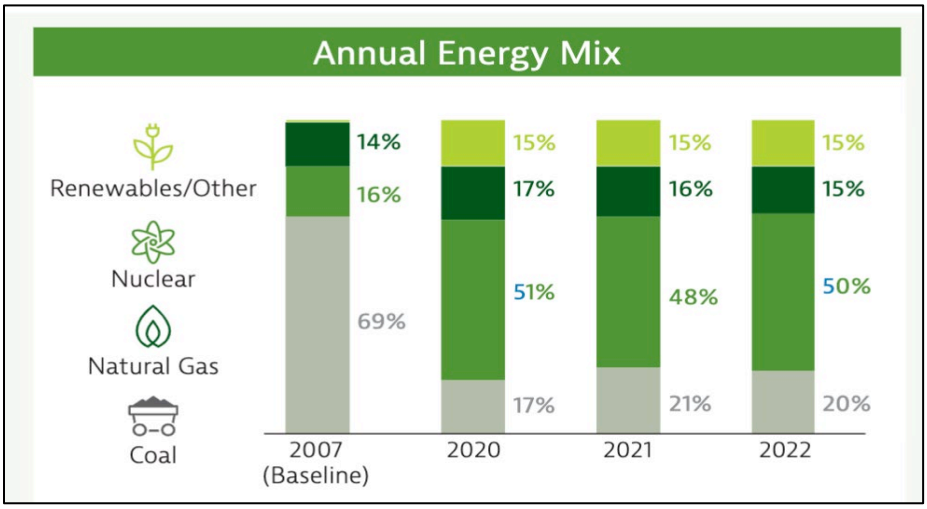
Figure 4: Georgia Power generation mix, 2022



Source: Georgia Power Company, Facts & Figures, 2023, available at: https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/facts_figures_2023.pdf.

Georgia Power's parent company, Southern Company (including Georgia Power's generation) uses natural gas equal to all other technologies combined in 2022.

Figure 5: Southern Company's historical annual energy mix



Source: Southern Company, Electric Operations: Energy Portfolio Transition & Scenario Planning, December 2023, available at: https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/net-zero-transition/2023_final_energy%20portfolio%20transition%20scenario%20planning%20fact%20sheet.pdf.

While the larger and deeper natural gas market in Texas could not avoid dramatic price volatility, the Texas electricity market is only 42.6% supplied by natural gas.[11] Southern Company and Georgia Power have higher dependence on natural gas for electricity than Texas. Thus, any additional growth in generation based on natural gas should be examined carefully as dependency rates of 42.6% (Texas), 48% (Georgia Power), or 50% (Southern Company) are all in a category any casual observer would note as very high and therefore susceptible to natural gas price volatility.

Q. CAN THE PRICE VOLATILITY IMPACTS BE MITIGATED THROUGH FINANCIAL INSTRUMENTS OR HEDGES?

A. No. The price volatility can be removed by using hedges and related financial instruments, but the cost would be so high that over the long run, there would likely be no financial benefit. Basically, hedging requires another party to take the responsibility of the price volatility risk. Like buying insurance, the cost of the policy is purposely designed to price the risk plus add a premium for profit and administration of the insurance. Today's natural gas price volatility is squarely on the shoulders of the electricity customer. Hedging the volatility would provide a stable and predictable fuel cost, but the cost of the hedges would wind up being paid by customers creating no financial benefit over time.

[11] Texas Office of Comptroller, Texas Comptroller Energy Tour: Statewide Overview, available at: https://comptroller.texas.gov/economy/economic-data/energy/2023/texas.php#:~:text=In%202022%2C%2042.6%20percent%20and%2016.6%20percent,biomass%20sources%20provided%20most%20of%20the%20remainder.

Q. WHAT CAUSES SUCH EXTREME VOLATILITY IN THE PRICE OF NATURAL GAS?

A. In a word: scarcity. Driven by supply and demand imbalances, natural gas prices go up when demand exceeds supply. Similarly, prices will decline when demand is lower than supply. Natural gas is unique as a large commodity market because it can only be transported under pressure in pipelines. This characteristic means the natural gas marketplace is very regionalized based on the availability of production, storage, and transport infrastructure to service demand in those locations. This is why natural gas is frequently priced by zones with large differences in price between zones occurring regularly. This is very different from the situation with oil—the only commodity which trades more than natural gas in the United States—since oil can be transported easily at normal atmospheric pressure in barrels. The need for natural gas to remain under pressure means the storage and transport is very limited relative to other commodities and greatly increases the locations where there can be imbalances in supply and demand.

Q. HOW WOULD YOU LOOK AT THE SUPPLY AND DEMAND RISKS WHICH AFFECT GEORGIA POWER?

A. Georgia Power has studied its load requirements and knows that about 48% of generated power will come from natural gas. While Georgia Power may not be able to predict other users of natural gas, the assessment of demand is not the primary concern. The problem is determining the dynamics affecting supply to meet the growing needs of Georgia Power and the other users in the geographic region.

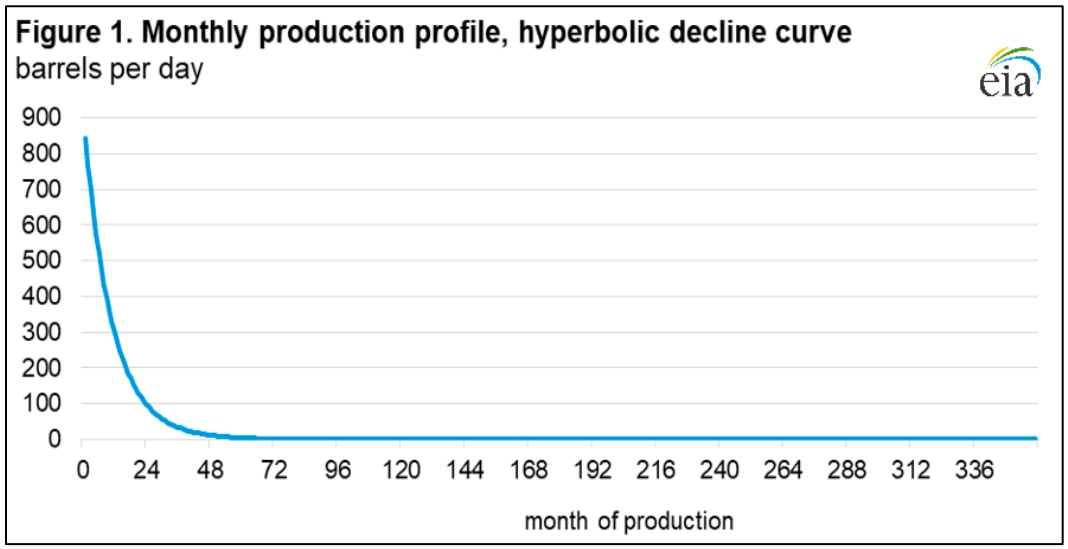
There are three major factors with challenging trends to consider:

1) Natural gas production decline curve
2) Natural gas systemwide storage
3) Transportation and distribution with LNG (Liquified Natural Gas) as an option

Q. EXPLAIN THE NATURAL GAS PRODUCTION DECLINE CURVE.

A. The growth in natural gas production has been driven by technology improvements such as directional/horizontal drilling and hydraulic fracturing. These advances in technology allowed natural gas to be extracted economically from new areas. A unique characteristic of the technology is that the production volume of each well declines very rapidly in the first few years. This is very different from conventional wells which produce at a much more stable and predictable rate over its lifetime. Modern wells (since 2008) have been tracked and their production decline curve is illustrated below:

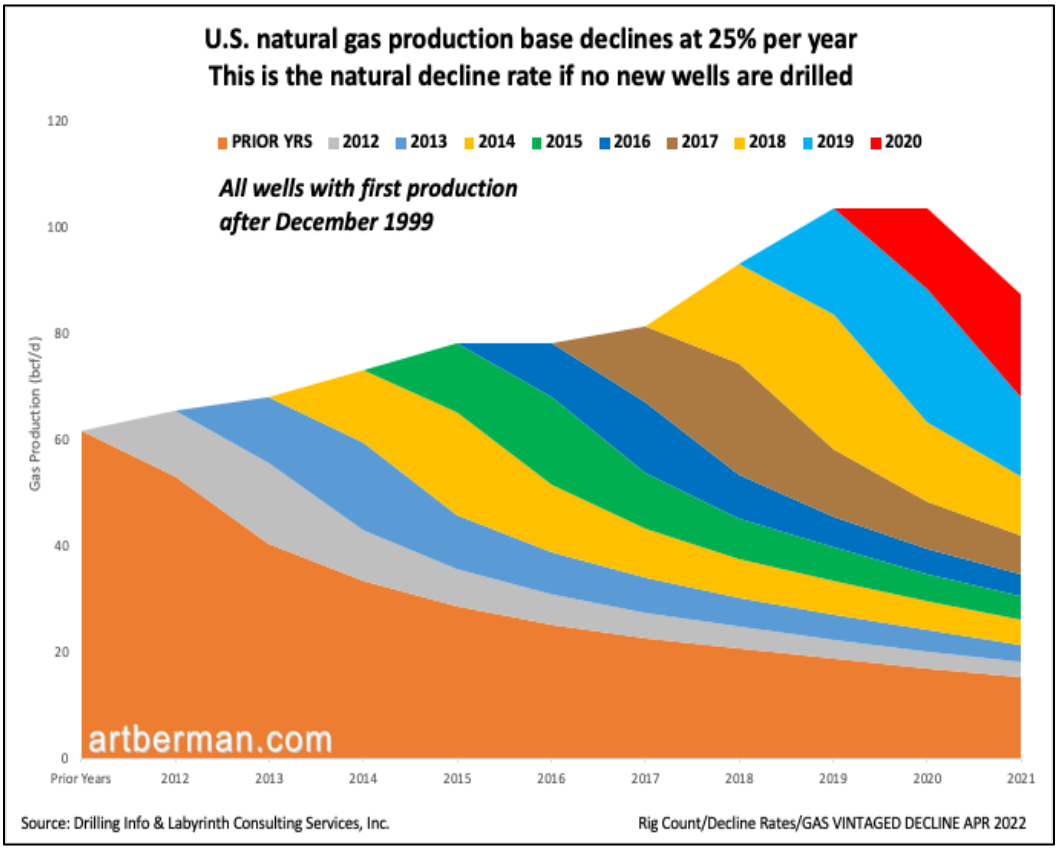
Figure 6: Monthly natural gas wells production profile, hyperbolic decline curve



Source: US Department of Energy, Energy Information Administration, Production Decline Curve Analysis in the Annual Energy Outlook 2023 (March 16, 2023), available at: https://www.eia.gov/analysis/drilling/curve analysis/.

The cumulative effects of the decline in production is easily seen in this chart below from energy consulting company Labyrinth Consulting Services, Inc. Each colored section represents a year of production with the top portion representing the total volume of natural gas produced. This chart also shows how the orange color (cumulative production prior to 2012) has a shallow decline slope versus modern wells which use horizontal/direction drilling with hydraulic fracturing. The current average of a 25% overall production decline means the industry must increase production 25% just to get back to the prior year's level. We believe the commission should study this issue carefully just as the natural gas industry is focused on it because it is the starting point for determining the natural gas overall supply which can be used.

Figure 7: US natural gas production decline rate



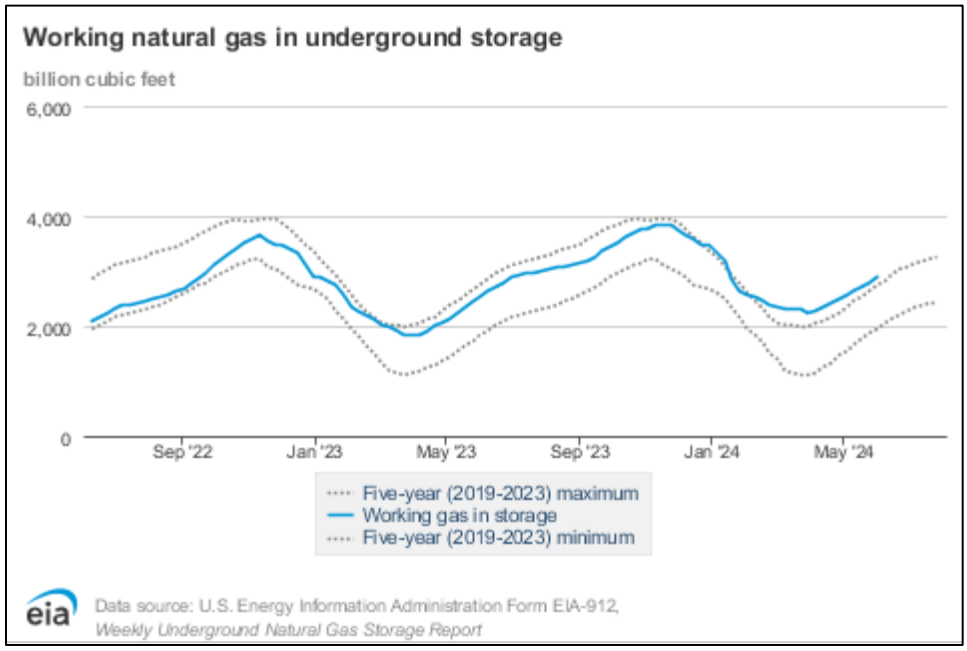
Source: Labyrinth Consulting Services, Inc.

Q. YOU ALSO POINT OUT STORAGE OF NATURAL GAS IS AN ISSUE CONTRIBUTING TO VOLATILITY. PLEASE EXPLAIN.

A. Like many businesses, some stock of inventory is held to ensure sufficient products are available to meet the needs of buyers which may have variation in their purchase behavior. For natural gas, this storage typically takes place in large underground caverns. The pattern of behavior has been to keep production wells running at a steady (optimized cost) rate and when demand for natural gas is low, send the unused production to one of these storage facilities. When demand is high and the production wells cannot meet the load, additional natural gas drawn from storage

is used to meet demand. Since there are costs to store natural gas (transport, cleaning, pressurizing, etc.), the business seeks an equilibrium to optimize profitability, not availability. It is also costly to permit and build a storage facility. The United States has not changed its total storage for natural gas at a rate which matches the industry growth and increase in usage volatility. Total storage over the last five (5) years is show below:

Figure 8: Working natural gas in underground storage, Sep 2022 – May 2024

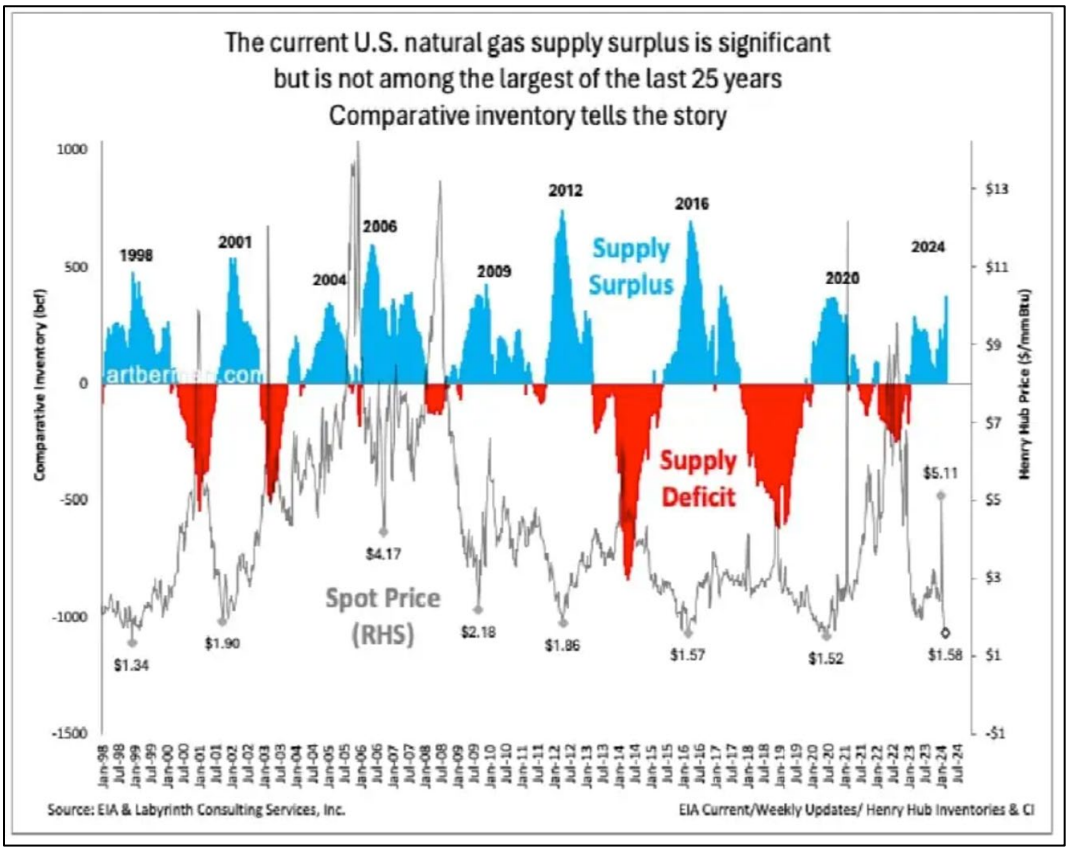


Source: US Department of Energy, Energy Information Administration, Natural Gas Weekly Update.

The dotted lines represent the maximum and minimum storage capacity experienced over the last 5 years ending 2023. The maximum storage figure has been stubbornly stuck at 4 trillion cubic feet, yet demand for natural gas has been historically growing. It's not hard to see how a limited amount of storage leads to periods of shortages.

The periods of natural gas supply and surplus can be seen to be a fairly common phenomenon over the past 25 years.

Figure 9: US natural gas inventory, 1998-2024

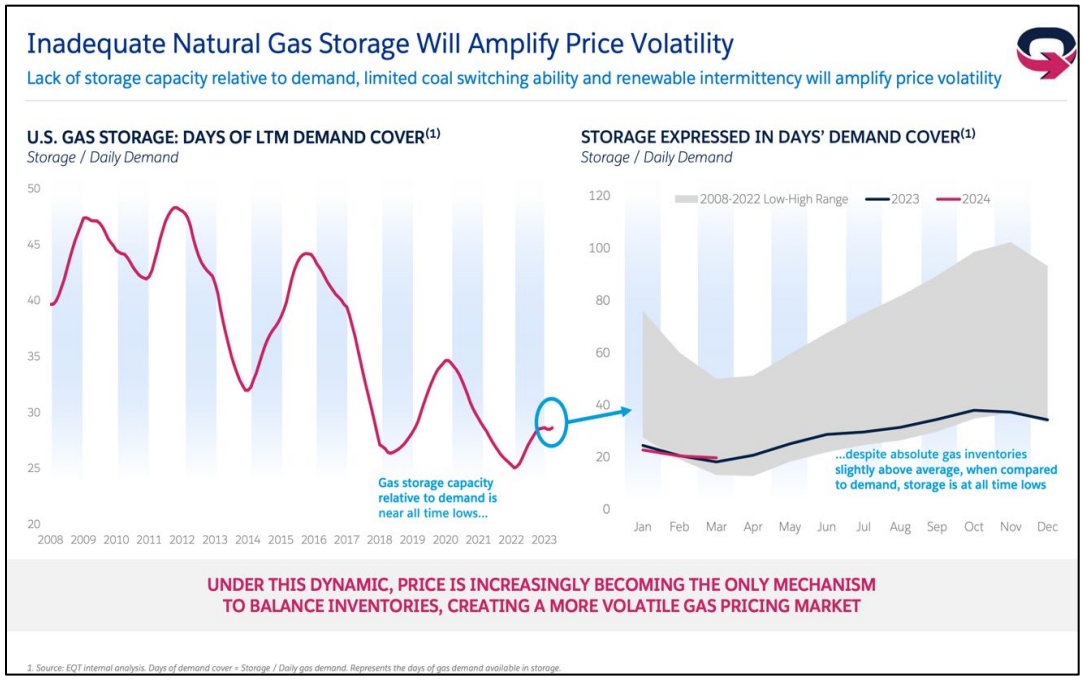


Source : Art Berman, "There's Nothing Confusing About Natural Gas Prices" (Mar. 8, 2024), available at: https://www.artberman.com/blog/theres-nothing-confusing-about-natural-gas-prices/.

The black line is the spot price of natural gas (the price paid by most utilities). It should not be a surprise to anyone to see that prices tend to rise when there is a supply deficit. Also worth noting is the fact that price declines tend to develop during times of surplus. It is this extreme volatility which makes it financially risky to invest in natural gas storage capacity as it takes years to build a storage facility.

The USA's largest natural gas producers, EQT (NYSE: EQT), summed it up to their shareholders with this slide presented in April 2024:

Figure 10: US natural gas storage and expressed demand



Source: EQT Investor Presentation: First Quarter 2024 Results (Apr. 23, 2024), available at: https://s24.q4cdn.com/922296017/files/doc_financials/2024/q1/EQT-Q1-2024-Earnings-Presentation.pdf.

The net storage in the USA when measured in how many days of demand can be served is near an all-time low since 2008. EQT makes the common-sense conclusion that without much storage, any shortages can only lead to a price reaction until enough demand destruction is met or customers left without natural gas.

Q. YOUR THIRD SUPPLY RELATED TOPIC IS TRANSMISSION AND DISTRUBTION REALTED. ELABORATE.

A. Natural gas is kept under a wide range of pressure in order to transport it in a liquid form. The pipelines required to deliver natural gas from production and storage to users like Georgia Power tend to be concentrated as a result of permitting, rights of way, cost, pressure, safety, and other factors. The state of Georgia does not produce natural gas or refine petroleum products so the concentration of primary infrastructure is higher than the national average. Currently, the Transcontinental Gas Pipeline (Transco) and the Southern Natural Gas Pipeline (SNG) are the primary ways natural gas enters the state. When demand grows, pipeline capacity must be increased. A third major pipeline called the Sabal Trail Gas Transmission Pipeline (Sabal Trail), transports natural gas from Georgia to Florida and will have 162 miles out of 517 total miles within Georgia.[12]

Of the three areas of concern which affect natural gas supply, transmission and distribution is the easiest to solve because it is the only area which has shown positive and quantifiable progress. Sabal Trail was proposed in 2014, achieved Phase I operations in 2017, achieved Phase II operations in 2020, and will conclude with Phase III in 2025.[13] Like most major natural gas pipeline projects, there were many stakeholders with strong opinions early in the project, but as construction

[12] Sabal Trail Transmission, available at: https://sabaltrailtransmission.com/; *also see* "Sabal Trail Gas Transmission Pipeline," *Global Energy Monitor Wiki* (last updated Aug. 11, 2023), available at: https://www.gem.wiki/Sabal_Trail_Gas_Transmission_Pipeline.

[13] "Sabal Trail Gas Transmission Pipeline," *Global Energy Monitor Wiki* (last updated Aug. 11, 2023), available at: https://www.gem.wiki/Sabal_Trail_Gas_Transmission_Pipeline.

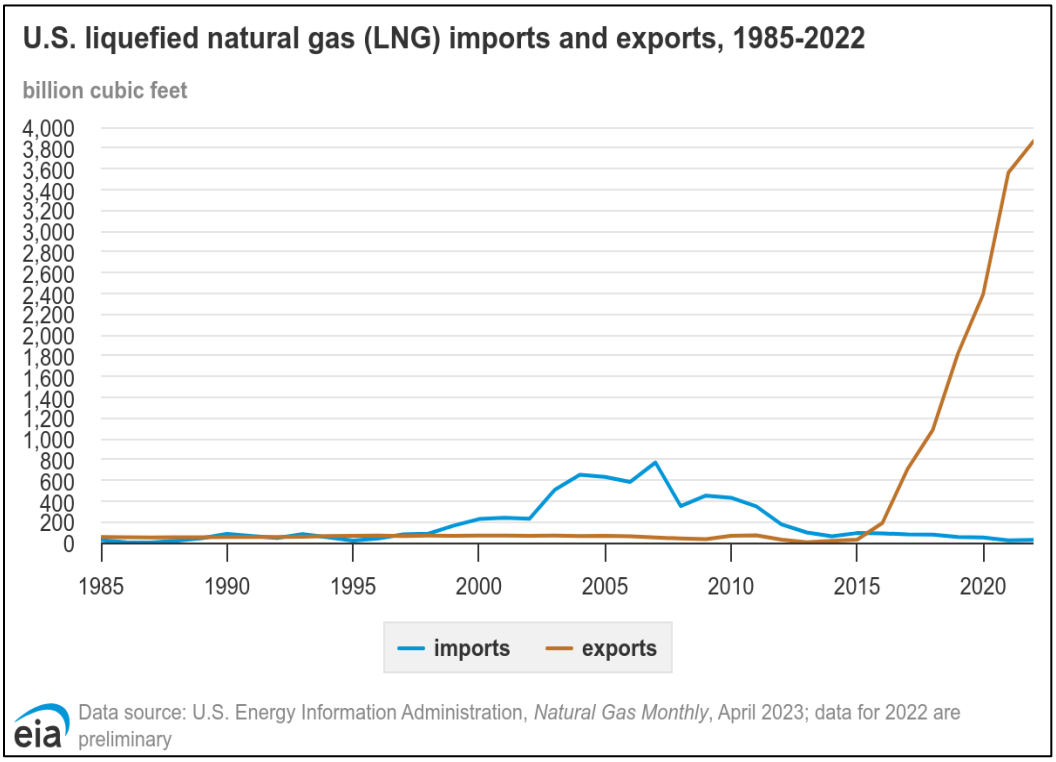
began, the pipeline has progressed to a point of near completion in about 11 years. Almost any natural gas pipeline takes at least 3 to 4 years and larger ones tend to take even greater time.[14] The amount of time is increased dramatically if the pipeline crosses state borders, like the Sabal Trail. Indeed, the federal approval process at the initial proposal stage has gone from 386 days in 2008 to 587 days in 2019 for all natural gas pipelines according to Bloomberg Intelligence.[15] However, an important distinction is that while the supply constraint impacts from transmission and distribution may be solvable with enough time and money, the production decline curve and storage issues have shown virtually no improvement. Additionally, the time frames shown for transmission and distribution solutions to increase local natural gas supply has been shown to take a decade or longer while volatility spike due to shortages currently occur approximately every 4 years.[16] Therefore, additional transportation and distribution alone does not appear to fix the volatility challenges the Yates CTs will face if certification is granted. There is a strong likelihood for periods of extreme price volatility over the Yates CTs anticipated operating life, making this a risky and costly investment for ratepayers.

[14] Bob Bookstaber, "As Time Goes By—The Long Gestation for Gas Pipeline Projects," *Power* (Nov. 6, 2012), available at: https://www.powermag.com/as-time-goes-bythe-long-gestation-for-gas-pipeline-projects/.
[15] Hiroko Tabuchi and Brad Plumer, "Is This the End of New Pipelines?," *New York Times* (July 8, 2020), available at: https://www.nytimes.com/2020/07/08/climate/dakota-access-keystone-atlantic-pipelines.html.
[16] US Department of Energy, Energy Information Administration, "U.S. natural gas price saw record volatility in the first quarter of 2022" (August 24, 2022) available at: https://www.eia.gov/todayinenergy/detail.php?id=53579.

Q. HOW DO LNG EXPORTS AFFECT SUPPLY?

A. LNG exporting is the act of taking natural gas and shipping it to a destination over water. The technology requires the natural gas to be super-cooled and placed under modest pressure. Unique facilities are required to perform the initial gas freezing to negative 260 degrees (Fahrenheit) or lower and then place the liquified gas into specially designed ships; additional facilities at the destination port are required to undertake a reversal of this process. While the cost to do this may be high, there are several major natural gas consuming markets, including the European Union, Japan, and South Korea that have regular prices far in excess of the additional cost to engage in LNG activities. Recent geopolitical events have caused prices in these international markets to rise from time to time above the already known and sustained higher than USA prices. This financial incentive has been very large for many years such that the USA continues to build LNG export terminals to supply this market.

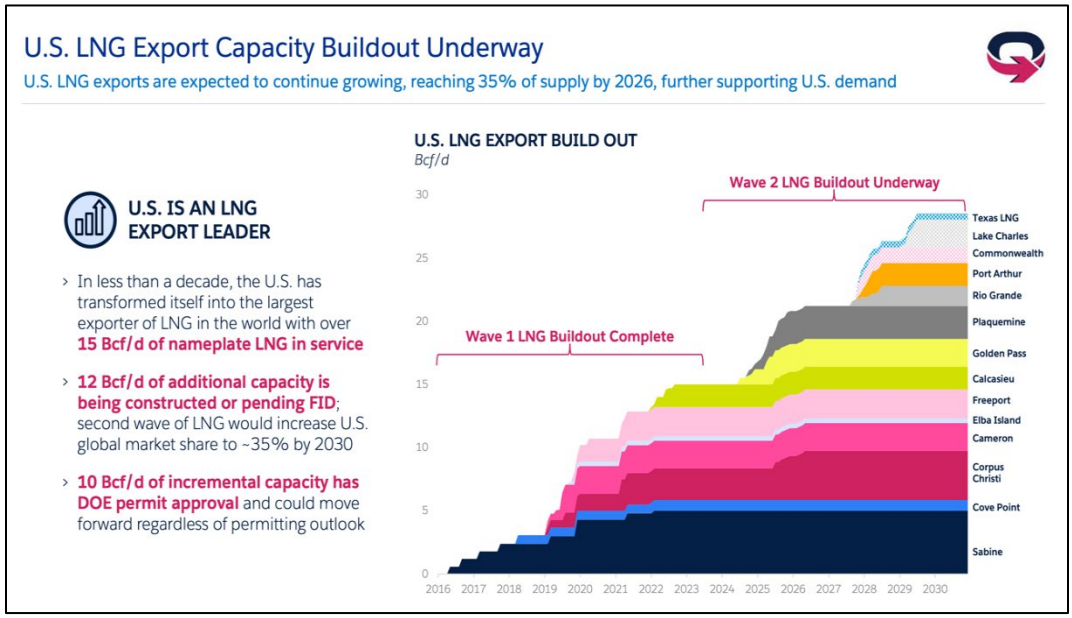
Figure 11: US liquefied natural gas imports and exports, 1985-2022



Source: US Department of Energy, Energy Information Administration, Natural gas explained (last updated Aug. 11, 2023), available at: https://www.eia.gov/energyexplained/natural-gas/liquefied-natural-gas.php.

The nation's top natural gas producer notes that LNG volumes should double current levels in the next 5 years:

Figure 12: US liquified natural gas export capacity buildout



Source: EQT Investor Presentation: First Quarter 2024 Results (Apr. 23, 2024), available at: https://s24.q4cdn.com/922296017/files/doc_financials/2024/q1/EQT-Q1-2024-Earnings-Presentation.pdf.

If the LNG export terminal build out continues as approved and permitted, the USA will ship about 26% of all-natural gas in 2030, up from the current proportion of 13.6%.

Figure 13: US natural gas consumption, week of 5/30/2024

U.S. natural gas consumption - Gas Week: (5/30/24 - 6/5/24)

	Average daily values (billion cubic feet)		
	this week	**last week**	**last year**
U.S. consumption	67.0	66.8	68.4
Power	36.0	35.8	36.9
Industrial	21.8	21.5	21.7
Residential/commercial	9.2	9.5	9.7
Mexico exports	6.8	7.0	6.5
Pipeline fuel use/losses	8.5	8.6	8.9
LNG pipeline receipts	13.2	13.0	12.4
Total demand	95.5	95.4	96.2

Data source: S&P Global Commodity Insights
Note: This table reflects any data revisions that may have occurred since the previous week's posting. Liquefied natural gas (LNG) pipeline receipts represent pipeline deliveries to LNG export terminals.

Source: US Department of Energy, Energy Information Administration, Natural Gas Weekly Update, week ending Jun. 5, 2024, available at: https://eia.gov/naturalgas/weekly/archivenew ngwu/2024/06 06/#tabs-supply-2.

Q. WHAT ACTIONS SHOULD BE CONSIDERED IN LIGHT OF THESE TRENDS?

A. The recognition that natural gas prices are extremely volatile and likely to remain that way for the foreseeable future is a good starting point. The acknowledgement that the industry supplying natural gas is motivated to serve overseas market first and domestic needs second with any residual supply that cannot be sold overseas is another important observation. Since the natural gas industry is motivated by its ownership to be profitable in a competitive industry, it is not likely to ever conduct

business on the basis of a "reliability at all costs" approach. Electric utilities are designed to be highly reliable so creating a large dependency between these two industries increases the chances one or both industries will be less likely to achieve their goals. In my view, the Commission must take care to limit exposure to any single technology. The amount of dependency on natural gas for generation by Georgia Power is already extremely high. Further increasing the utility's dependency on natural gas will only expose the system and users to greater incidents of price shocks. Updating the policies on who and how much of the fuel cost should help the key stakeholders achieve a better level of exposure and risk concentration.

Another prudent action would be the use of the All-Source RFP procurement process already underway in Georgia covering years 2029-2031 to fully assess the availability and pricing of all options and technologies from this time period and future All-Source RFPs to cover periods beyond 2031.[17] A delay in the certification process given the size, lifetime, and likely operating cost of the Yates CTs, would allow the Commission to obtain more information to make a better decision.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[17] *See* Georgia Power Company, All-Source Capacity Request for Proposals for 2029-2031, available at: https://gpc2029-2031all-sourcerfp.accionpower.com/_gpc_2301/home.asp.

Exhibit AL-1
Resume of Albert Lin

ALBERT LIN

SKILLS

- **Equity Investment and Valuation**
- **Broker-Dealer Principal/Manager (FINRA regulated)**
- **Energy Generation Development (IGCC/CCGT)**
- **Board of Directors (Governance) of publicly traded and private companies**

SUMMARY

Finance executive and entrepreneur in capital markets focused on consulting to the energy industry in recent years. Providing perspective and analysis of impacts of energy policy when new technology and practices are present constitute most consulting engagements.

EXPERIENCEHIGHLIGHTS

Consultant | Gizmo Global | 2015-Present

Financial Consulting focused on the energy industry with focus on the electricity system of the USA. Acted in capacity of executive, manager, and consultant to The Finance Lab as well as other electricity dense users such as data centers

Energy Policy Analysis | Finance Lab | 2020-Present

Starting the Pearl Street Station Finance Lab to assist energy policy stakeholders on financial incentives and implications. Providing key features of legislation governing fuel clause adjustment (CO Bill 2022/2023) and analyzing the impact of ROE rate setting for regulated utilities in the United States

CEO and Chairperson of the Board | EmberClear | 2008-2015

Electricity Generation Asset Developer. Permitted, developed, sold IGCC and CCGT power plants to PE Funds and Large International Power Plant Operators ranging in sizes from 330 – 450 Megawatts

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Managing Director | AmTech | 2002-2007

Co-Founder for a Technology Focused broker dealer. Acted as Director of Research for 24 equity analysts. Sold to a publicly traded competitor after annual revenue per employee exceeded $1MM in 2007

Equities Analyst | Various | 1992-2002

Sell-side equities analyst in wireless communications for SG Cowen & Co, Soundview Financial, and Rauscher Pierce.

Buy-side technology portfolio manager for

The Abernathy Group, Meerkat Capital, and Ivory Capital. Managed portfolio of high growth technology equities in a long-short strategy.

Finance Manager | Verizon | 1989-1992

Various finance and audit positions at regulated telecommunications company General Telephone & Electric which became Verizon Communications. Prepared financial analysis used for regulatory and shareholder meetings

EDUCATION & OTHER

University of Texas @ Austin (1989)

BS: Finance

BA: International Business

Honors Masters Business Degree

Guest Lecturer at Boston College Graduate School of Business "Blockchain & Crypto Currencies"

FINRA Series 7,24,63,65 (licenses granted, but no longer sponsored)

Exhibit AL-2

Lawrence Berkeley National Laboratory: All-Source Competitive Solicitations, March 2021



All-Source Competitive Solicitations: State and Electric Utility Practices

March 2021

Dr. Fredrich Kahrl, 3rdRail Inc.

Project Manager and Technical Editor:
Lisa Schwartz, Lawrence Berkeley National Laboratory

All-Source Competitive Solicitations: State and Electric Utility Practices

Dr. Fredrich Kahrl, 3rdRail Inc.

Project Manager and Technical Editor:
Lisa Schwartz, Lawrence Berkeley National Laboratory

March 2021

About the Author

Dr. Fredrich Kahrl is an independent researcher and consultant. He has worked with North American regulators and utilities on a range of critical issues facing the electricity industry, including grid modernization investment economics, distribution system platforms and markets, wholesale market design and evaluation, resource planning, retail rate design, and resource adequacy program design. Previously, he was a Director at Energy and Environmental Economics (E3). He holds Ph.D. and M.S. degrees in Energy and Resources from the University of California, Berkeley, and a B.A. in Philosophy from the College of William & Mary.

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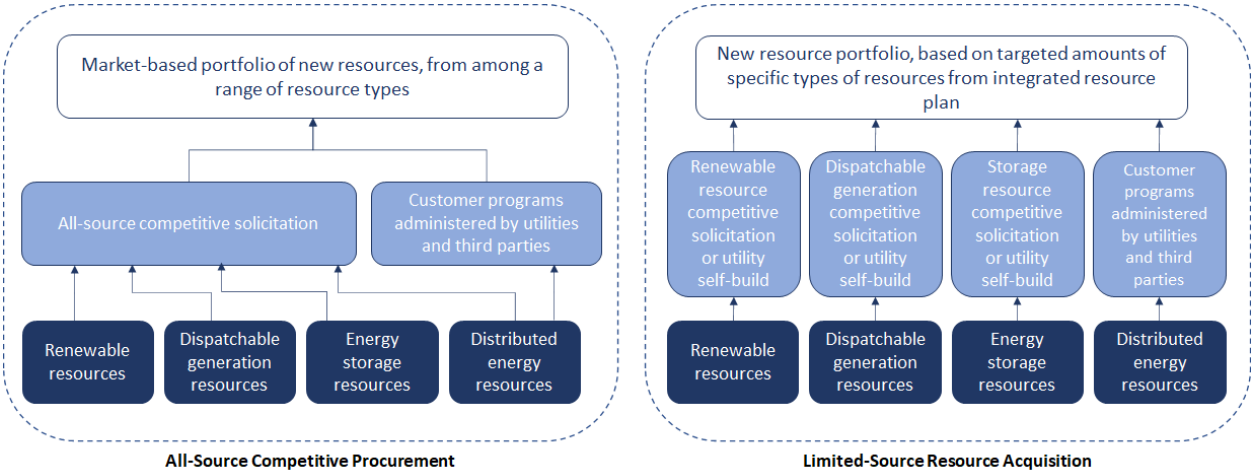
Summary

All-source competitive solicitations for electric utility procurement allow proposals for different types of energy resources and technologies—including utility-scale resources and distributed energy resources (DERs), new and existing resources, and utility-owned, customer-owned, and third party-owned resources—to compete to meet a utility's overall resource needs. Utilities solicit offers from suppliers, including their affiliates, and often include a utility self-build option. Interest in this procurement strategy emerged in the 1980s, then slowed beginning in the late 1990s as many states established retail competition and created dedicated procurement processes for renewable energy and demand-side resources. Potential opportunities for new types of generation and energy storage technologies and rapid changes in costs are driving renewed interest in all-source solicitations.

In contrast, utilities use *limited-source resource acquisitions* to procure different kinds of resources through separate, dedicated competitive solicitations and may not be required to competitively procure some kinds of resources (Figure 1).

The strength of all-source competitive procurement is in its potential ability to identify a market-based portfolio of new resources from among a range of resource types, to meet utility needs at low cost and with an acceptable level of risk. In addition, the portfolio approach used in all-source competitive procurement allows for integrated procurement of resources that have interactive effects, such as wind, solar, and energy storage. Interest in all-source solicitations also is increasing as a strategy to address greater uncertainty in a time of rapid technological change.

Figure 1. Illustration of All-Source Competitive Procurement and Limited-Source Resource Acquisition



Note: This figure is for illustrative purposes and does not capture the nuances of different approaches to utility planning and resource acquisition across states. Some kinds of DERs may not be eligible to participate in all-source competitive solicitations.

This report provides an overview of principles, practices, and emerging issues in all-source competitive solicitations by vertically integrated investor-owned utilities, including those that participate in independent system operator (ISO)/regional transmission operator (RTO) markets and those that do not. It first reviews the history of electric utility all-source solicitations, then results over the last decade (Table 1). The report also provides an overview of goals, design trade-offs, and process stages and examines

solicitation design and implementation options and issues, including methodologies for bid evaluation. The report draws on a review of regulatory documents, resource plans, solicitation materials, independent evaluator reports, and scholarly literature. While the report focuses on solicitations for bulk power system needs, it also briefly discusses solicitations for non-wires alternatives for distribution system needs, as well as considerations for coordinating both types of procurements.

A growing number of utilities have undertaken all-source competitive solicitations for bulk power system resources. The results illustrate the potential of all-source solicitations as a tool for discovering competitive market prices across a range of technologies and for continuously optimizing resource portfolios in response to changing market conditions. For example, in Public Service Company of Colorado's (PSCo's) 2013 all-source solicitation, the utility received only one energy storage bid, which was not cost-competitive with other resources. In its 2017 all-source solicitation, PSCo received 28 bids for stand-alone battery storage and 105 bids for battery storage paired with other resources and selected 250 megawatts (MW) of battery storage.

The increasing competitiveness of battery storage is a key driver of interest in all-source competitive solicitations. Battery storage, and energy storage more broadly, is a unique resource. It can function as both a generator and a load, is "energy-limited" in the sense that it relies on other generating resources to provide its energy, and has the ability to quickly start up and rapidly respond to changing system conditions by charging and discharging. Battery storage has a short construction lead time and can be sited almost anywhere in the electricity system. These unique characteristics create challenges for directly comparing the economics of storage and natural gas-fired generation and for understanding the value of storage in a resource portfolio that includes significant solar and wind generation. All-source competitive solicitations provide a market-based mechanism for assessing the value of energy storage as part of a utility's overall resource portfolio.

All-source competitive solicitations are by nature complex. Utilities may receive bids for new or existing generation, energy storage, demand-side resources, or combinations of these resources with multiple ownership structures. Because of this complexity, all-source solicitations require significant investments in process design and implementation, and their design involves consideration of trade-offs in stakeholder participation, transparency, time, flexibility, and discretion.

At the distribution system level, a growing number of state public utility commissions (PUCs) are requiring regulated utilities to establish regular all-source solicitation processes for non-wires alternatives to traditional distribution infrastructure investments. For instance, the New York Public Service Commission requires electric utilities to consider non-wires alternatives in their annual capital plans for distribution. Non-wires alternatives procurement has the potential to reduce distribution system costs, particularly with increased electrification of building end uses and transportation. Like all-source solicitations for bulk power system resources, non-wires solicitations are complex and require thoughtful design.

This report identifies several considerations for state PUCs as they decide whether to allow, encourage, or require utilities to use all-source competitive solicitations to acquire new bulk power system resources and non-wires alternatives to defer certain types of distribution system investments. It also discusses considerations for design and oversight of all-source solicitations. These considerations are intended to be broadly applicable to reflect different vantage points across states.

***State PUCs play a critical role in building confidence in the fairness and integrity of the solicitation process* (Chapters 2 and 3).** A well-designed competitive solicitation process that sets fair rules for stakeholder participation, transparency, participation, bidder requirements, evaluation, and timelines has a greater chance of encouraging more participants and competitive and innovative bids.

***Utility resource plans provide a foundation for all-source solicitations* (Section 3.2).** Integrated resource planning and all-source solicitations are interactive. Resource plans provide several essential ingredients for all-source solicitations, including resource needs, frameworks for evaluating expected cost and risk, and modeling inputs, assumptions, and decision criteria. All-source solicitations can provide market-based cost inputs for resource plans. Enhancing the analytical rigor of resource plans also can enhance the quality of all-source solicitations by providing a stronger foundation for the identification of resource needs and evaluation of bids.

***All-source competitive procurement can complement state energy policies* (Section 3.3).** All-source solicitations are, by definition, resource- and technology-agnostic, but they can complement state energy policies through design alternatives. For instance, utilities can identify minimum needs for policy-driven resources in all-source solicitations, while having flexibility to exceed those procurement levels for cost-effective bids, or PUCs can establish dedicated procurement processes for renewable energy, energy storage, and demand-side resources to procure any residual resources needed for policy compliance.

***Net value is a more important metric than cost in evaluating bids* (Section 3.5.3).** Evaluation methods for all-source solicitations must be able to evaluate on an equivalent basis bids from a wide variety of resource types, from utility-scale solar photovoltaic (PV) systems to natural gas combustion turbines to customer-sited batteries. The appropriate metric for economic evaluation and in regulatory proceedings is net value, or a resource's market value and other benefits minus its costs. Models typically used in bid evaluation assess bids based on their net value.

***Ongoing efforts are needed to improve bid evaluation methods* (Section 3.5.4).** The rapid increase in cost-competitive bids from solar PV, wind, and battery storage resources are creating a host of methodological challenges for bid evaluation, including methods for calculating capacity credits, integration costs, the value of real-time flexibility, congestion costs and benefits, transmission and distribution deferral, and natural gas price risk. Valuing resilience is another emerging challenge for bid evaluation methods. PUCs can play an important role in encouraging methodological improvements by establishing clear principles and providing more explicit guidance on specific evaluation issues.

***New opportunities are emerging for participation of DERs in all-source solicitations* (Sections 1.3, 3.4.3, and 3.5).** DER participation—particularly for energy efficiency projects—has generally been low in all-source solicitations for bulk power systems, raising questions over whether these solicitations are an effective mechanism for DER procurement. At the same time, with ongoing improvements in DER technologies, solicitations, evaluation methods, and contracting, there are emerging opportunities for some types and combinations of DERs to participate and be selected in all-source solicitations. PUCs can explore these emerging opportunities, investigate and address potential obstacles to DER participation, and explore ways to build complementarity between DER participation in all-source solicitations and utility and third-party DER programs.

***Energy storage's unique evaluation challenges warrant systematic analysis by utilities* (Sections 1.4 and 3.5).** Energy storage can provide a range of values to utilities that are incompletely captured in utility planning models, including local resource adequacy, congestion management, rapid startup, real-time dispatch flexibility and ramping, and resilience. To encourage more accurate valuation of storage in all-source procurement, PUCs can consider requiring utilities to undertake a systematic review of storage values and evaluation methods, complementing the Federal Energy Regulatory Commission's (FERC's) requirement for ISOs/RTOs to review storage participation in wholesale markets (Order 841).[1]

[1] 162 FERC ¶ 61,127.

***Ensuring comparable evaluation between utility-owned and non-utility-owned resources presents ongoing challenges for PUCs* (Section 3.5)**. State PUCs must assess, with the assistance of independent evaluators, whether utilities' evaluation and selection of new resources, including bids by utility affiliates and utility self-build proposals, are fair and in the ratepayers' interests. In these assessments, PUCs also need to ensure that utility self-build proposals are comparable to competitive offers, in terms of their short-term and longer-term risks to ratepayers. Proactive, clear rules and expectations for utility ownership can help to ensure that selection of resources is objective and impartial. Regulatory judgment by PUCs, relying on strong institutional expertise and capacity, also is essential.

***Independent evaluators are indispensable in all-source solicitations for regulated utilities* (Section 3.6).** Through their roles in reviewing solicitation materials, facilitating communications with bidders, monitoring the solicitation process, verifying utility evaluation results, and overseeing contract negotiations, independent evaluators help to ensure a fair process. Independent evaluators balance the need for greater utility flexibility and discretion to select a portfolio across resource types and ownership structures with concerns about potential anticompetitive practices by utilities.

***All-source procurement for non-wires alternatives holds promise but requires ongoing improvements* (Chapter 4)**. Systematic procurement of non-wires alternatives is relatively recent. Ongoing improvements are needed in how utilities identify distribution system needs appropriate for non-wires alternatives, including their suitability for deferring or avoiding traditional capital investments; how utilities operate non-wires alternatives, relative to bulk power system markets; and how utilities and developers contract for non-wires alternatives. Additionally, several institutional questions remain, including issues related to overlapping federal and state jurisdiction and rules governing distribution system operation.

Glossary

Following are definitions of terms as used in this report.

All-source and limited-source. *All-source* refers to procurement from different resource and technology types, new and existing resources, and different ownership structures. *Limited-source* refers to solicitations in which the scope of resource acquisition is deliberately constrained—for example, a solicitation intended only to procure renewable resources or a utility proposal to build a natural gas-fired power plant identified in the action plan of an integrated resource plan.

Solicitation and procurement. *Solicitation* refers to the process through which utilities request bids for projects to fill a resource need, including the evaluation and selection of winning bids. *Procurement* can refer to same process and also may be used more specifically to refer to the acquisition of resources. The terms solicitation and procurement are used interchangeably in this report.

Requests for proposals, offers, and information. Competitive solicitations may be a *request for proposals* (RFP) or a *request for offers* (RFO) and may include a *request for information* (RFI). An RFP typically gives the bidder significant latitude to develop a proposal, whereas an RFO describes a well-defined need or project and the bidder provides an offer to meet the defined need. RFIs often are used to gauge developer interest and market conditions and do not require financially binding proposals or offers. This report focuses on RFPs.

Bulk power system and distribution system. The *bulk power system* includes power producing resources that aggregate to a total capacity greater than 75 MVA (megavolt-ampere, gross nameplate rating) and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kilovolts (kV) or above. This does not include facilities used in the local distribution of electric energy.[2] *Distribution system* refers to medium-voltage system (typically up to 35 kV) substations, feeders, lines, and other equipment that distribute electricity to and from customers.

Distributed energy resources and utility-scale resources. The National Association of Regulatory Utility Commissioners (NARUC) defines a *distributed energy resource* (DER) as "A resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar PV, wind, CHP [combined heat and power], energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)."[3] *Utility-scale* is typically defined in terms of project size (megawatts), though there is no standard industry threshold for the minimum size of utility-scale projects. This report uses the term utility-scale generically to refer to projects that are larger than a few megawatts, often juxtaposed against DERs.

Non-wires alternatives. *Non-wires alternatives* are non-traditional investments—including energy efficiency, demand response, distributed generation and storage, and managed electric vehicle charging—or market operations that may defer, mitigate, or eliminate the need for traditional transmission and distribution investments. For this report, the focus is on non-wires alternatives for distribution system needs.

[2] NERC (n.d).
[3] NARUC (2016).

Independent system operators and regional transmission organizations. An *independent system operator* (ISO) is a system operator that meets the 11 criteria (principles) established for ISOs in the Federal Energy Regulatory Commission's (FERC's) Order 888.[4] *Regional transmission organizations* (RTOs) are regional transmission operators that fulfill the minimum characteristics and functions of an RTO established in FERC's Order 2000.[5] FERC has approved four RTOs: New England Independent System Operator (ISO-NE), Midcontinent Independent System Operator (MISO), PJM, and Southwest Power Pool (SPP). Three ISOs—California ISO (CAISO), Electricity Reliability Council Texas (ERCOT), and New York ISO (NYISO)—operate within state boundaries and are not RTOs.

[4] 78 FERC ¶ 61,220.
[5] 89 FERC ¶ 61,285.

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1.0 Introduction and Background

Changes in policies, technologies, and markets are driving increased interest in all-source competitive solicitations. This report provides an overview of emerging practices and issues in their design and implementation based on review of regulatory documents, resource plans, solicitation materials, independent evaluator reports, and scholarly literature. The report seeks to inform state PUCs as they consider options for utility resource acquisition.

As used in this report, *all-source competitive solicitation* refers to electric utility procurement that allows proposals for different resource types, utility-scale and DERs, new and existing resources, and different ownership structures to compete to fill a utility resource need. This definition is intended to be broad; the report does not seek to adjudicate what qualifies as an "all-source" solicitation.

The report focuses on all-source competitive solicitations by vertically integrated investor-owned utilities for bulk power system needs.[6] It also briefly discusses competitive solicitations by investor-owned utilities for non-wires alternatives to meet certain distribution system needs, as well as ways in which PUCs and regulated utilities are beginning to coordinate procurements for bulk power resources and non-wires alternatives.

Many of the design and implementation issues related to all-source solicitations are common to all types of utility competitive procurements. However, all-source solicitations present unique challenges for PUCs and utilities. The report seeks to provide a comprehensive overview, while focusing on these unique challenges. References to a rich literature that spans more than three decades provide resources for more in-depth information on specific aspects of utility competitive solicitations.

1.1 Report Structure

This chapter provides four elements of essential background: a historical perspective on competitive solicitations by electric utilities; recent technology, policy, and market trends and how they have motivated renewed interest in all-source solicitations; recent trends in all-source solicitations; and the impact of energy storage as an emerging resource. The remainder of the report is organized as follows:

- **Chapter 2** describes goals and principles, design trade-offs, and process stages for all-source solicitations.
- **Chapter 3** discusses design and implementation options and issues across five areas for bulk power system solicitations: procurement rules and guidance, resource planning and all-source procurement, needs identification, RFP instrument design, and evaluation and selection.
- **Chapter 4** examines the design and implementation of all-source solicitations for non-wires alternatives as a strategy for deferring or avoiding capital expenditures for distribution system infrastructure.
- **Chapter 5** offers concluding thoughts.

[6] This scope includes utilities in states like California where utilities do not own significant generation but are primary load- serving entities and have a long-term procurement process.

1.2 Historical Perspective and Motivation

Competitive procurement for electric utility resources emerged from implementation of the 1978 Public Utility Regulatory Policies Act (PURPA),[7] as utilities and PUCs sought an alternative to avoided cost-based payments to qualifying facilities (QFs).[8] In some states, PURPA created significant uncertainty for utilities' management of their resource portfolios because of the potential for rapid increases in QF capacity in response to "above-market" avoided costs.[9]

Use of competitive procurement increased over the 1980s.[10] By the early 1990s, utilities in more than 20 states had conducted competitive bidding for new power supplies.[11] Many of these early solicitations were all-source, allowing bids from a range of supply-side and, in some cases, demand-side resources, and enabling participation by QFs, host utilities, other utilities, and later independent power producers (IPPs).[12]

Interest in all-source competitive procurement slowed beginning in the late 1990s, with the emergence of competitive wholesale and retail markets, changes in policies and regulations, low demand growth, and changes in technology and commodity costs. By the mid-2000s, most of the states that embraced competitive procurement during the 1990s had developed competitive retail markets for electricity.[13] In these states, incumbent utilities transitioned to serving as default service providers, shifting their procurement from long-term asset ownership and contracts to short-term purchases from third-party marketers. Of the 37 states[14] that eschewed retail electric competition over the first decade of the 2000s, PUCs in less than one-third maintained or developed rules requiring regulated utilities to use competitive solicitations to acquire new bulk power system resources.[15]

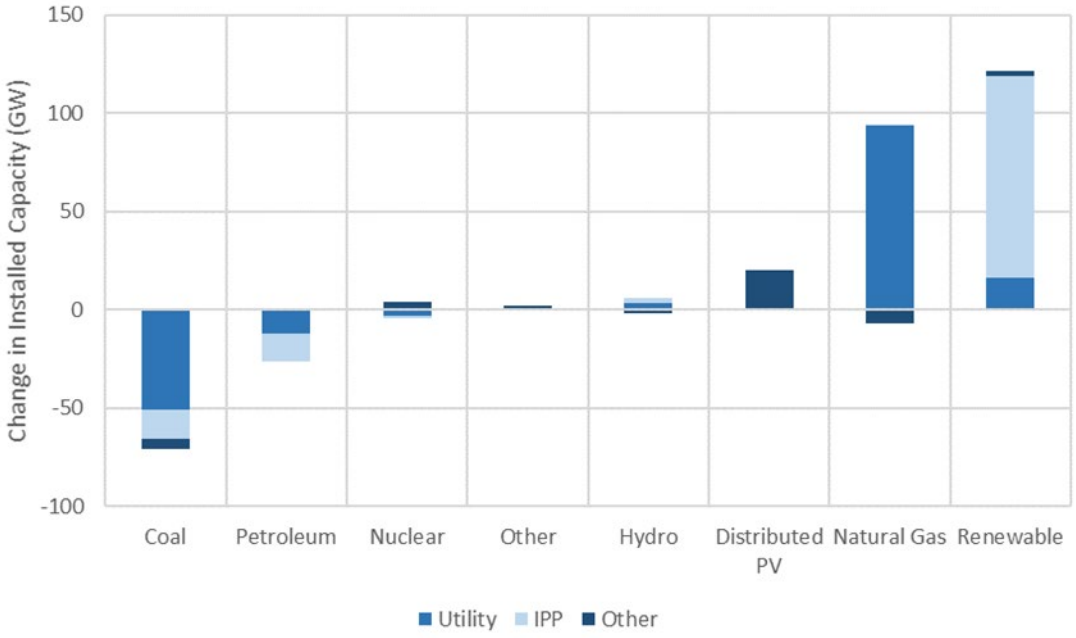
Changes in economics and policies over the 2000s and 2010s also shaped utility resource procurement. U.S. electricity demand growth has not yet recovered from the 2007–2009 recession, remaining essentially flat (0.3% percent per year growth) between 2010 and 2018.[16] Low demand growth limited utilities' need for new generation capacity mainly to replacing older coal- and oil-fired power plants and meeting state renewable energy mandates. Many states developed and extended renewable portfolio standards (RPS), requiring utilities to procure renewable energy through competitive solicitations that were designed to be renewable resource and technology neutral.[17] Natural gas prices remained

[7] 16 U.S.C. § 824a-3.
[8] Duann et al. (1988); Rose et al. (1991); Swezey (1993). For historical overviews of the emergence of competitive bidding in the electricity industry, see Duann et al. (1988); Kahn et al. (1989); Joskow (2000); Rose et al. (1991).
[9] *Above-market* refers to levels that are above the competitive cost of supply. Above-market avoided costs can result from rapid changes in relative costs, as occurred with rapid declines in the cost of natural gas generation in the 1980s and more recently with rapid declines in the cost of wind and solar generation. They also can result from a rapid increase in QF capacity, which can reduce long-run and short-run marginal costs—for instance, when an increase in QF capacity in a system that was short generation capacity suddenly results in excess capacity in the system. Challenges associated with avoided cost-based payments to QFs continued after the 1980s. For examples, see Kavulla and Murphy (2018).
[10] Central Maine Power was the first utility to conduct a competitive bid for power supplies, in 1984. For an overview of the evolution of competitive bidding over the 1980s, see Rose et al. (1991) and Swezey (1993).
[11] Rose et al. (1991); Swezey (1993).
[12] Ibid.
[13] Based on the surveys in Rose et al. (1991) and Swezey (1993). These states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, and Pennsylvania.
[14] Energy Information Administration (EIA) (2018). These 37 states include those that established limited direct access programs.
[15] A 2008 survey found that 10 states—Arizona, California, Colorado, Florida, Louisiana, Montana, Oklahoma, Oregon, Utah, and Washington—had done so (Tierney and Shatzki 2008). Another 2008 survey found that 13 states had policies requiring or encouraging competitive procurement (Basheda and Schumacher 2008).
[16] Data are from EIA, "Retail Sales of Electricity by State by Sector by Provider 1990–2018," https://www.eia.gov/electricity/data/state/.
[17] Wiser and Barbose (2008); Barbose (2019). Both sources discuss exceptions to resource and technology neutrality in RPS requirements.

persistently low after 2008, contributing to lower market prices and natural gas-fired generation's growing role as the default incremental resource to meet resource adequacy requirements.[18]

Changes in U.S. generation capacity over the late 2000s and 2010s reflected these trends. Between 2005 and 2018, most net generation capacity additions consisted of utility-owned natural gas generation and IPP-owned renewable energy generation (Figure 2).

Figure 2. Net Changes in U.S. Net Summer Generating Capacity by Energy Source & Producer Type, 2005–2018[19]



Note: Other includes IPP combined heat and power (CHP) plants and customer-owned generation. Hydro includes conventional and pumped hydropower. PV refers to solar photovoltaic. Utilities include investor-owned utilities, publicly owned utilities, and rural electric cooperatives.

More recently, renewed interest in all-source competitive procurement is driven by a confluence of changes in markets, policies, and technologies, including:

- The emergence of battery storage as a more competitive resource, along with questions about how storage should be valued and included in utility resource portfolios
- Significant reductions in the cost of solar PV and wind generation that are making these resources increasingly cost-competitive with natural gas-fired generation[20]

[18] See Mills et al. (2019). Data on natural gas prices to support this statement are from EIA, "Natural Gas Prices," https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm.
[19] Data are from EIA, "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State 1990–2018," https://www.eia.gov/electricity/data/state/.
[20] Bolinger et al. (2019).

- Growing uncertainty in the cost of new resources, reflected in large ranges in levelized cost estimates[21] and uncertainty in the delivered cost to individual utilities

- Renewed interest in demand-side resources, driven by new loads; expanded functionality of demand-side resources; state energy and climate policies; cost declines for information, control, and battery technologies; and growing concerns over power system resilience to extreme weather-related events and cyberattacks

Growing interest in all-source procurement is due to its potential to discover region-specific competitive costs for a range of new resources; support the development of optimized portfolios of generation, energy storage, and demand-side resources; enable utilities to continuously optimize their portfolios as relative costs change; and coordinate DER procurement with bulk system resource procurement.

1.3 Trends in All-Source Competitive Solicitations

A growing number of utilities have used or announced all-source competitive solicitations. Table 1 provides an overview of these solicitations over the last decade, including those in progress or announced.

The "Solicited Proposals" column in Table 1 shows the number of bids, projects, or bidders for each solicitation, if available based on publicly reported information.[22] The total number of bids is often larger than the total number of projects, as participants bid multiple variations of the same project—for instance, different contract lengths, ownership structures, and storage configurations. The significant number of proposals suggests that many of these solicitations have been competitive. Independent evaluators and PUCs have confirmed this.[23]

The results of the competitive solicitations in Table 1, in tandem with Table 2 and Table 3 illustrate several trends:

- *The increasing cost-competitiveness of solar PV and wind generation, inclusive of federal tax credits*. In the EPE 2017, PSCo 2017, and NIPSCO 2018 solicitations, solar PV and wind were selected based on offer price rather than for regulatory compliance.

- *The emergence of battery storage as a competitive resource*. Battery storage was selected in the SCE 2013, EPE 2017, and PSCo 2017 solicitations. PSCo's all-source solicitations illustrate the rapid emergence of battery storage. In its 2013 solicitation PSCo received one bid for stand-alone battery storage (about 50 MW); in its 2017 solicitation it received 28 bids (21 projects, 1,614 MW) for stand-alone battery storage and bids for battery storage paired with solar PV (87 bids, 59 projects, 10,813 MW), wind (11 bids, 8 projects, 5,907 MW), or combustion turbines (CTs) (7 bids, 3 projects, 476 MW).[24]

[21] NIPSCO (2018a).
[22] For instance, for the EPE and PNM solicitations only the number of bids appears to be publicly available.
[23] For examples, see SCE (2014); Colorado PUC (2018); Rose (2018); and EPE (2019).
[24] PSCo (2013); PSCo (2017b).

Table 1. All-Source Competitive Solicitations by Investor-Owned Utilities: 2010–2019 and 2020 Announced

Utility	Year	RFP Need	Solicited Proposals	Selected Resources
PacifiCorp [A]	2011	≤ 600 MW	N/A	Terminated due to lower than expected load growth
PSCo [B]	2013	250 MW	55 bids, 10,300 MW (ICAP, bids)	Gas PPA: 314 MW Wind PPA: 450 MW Solar PV PPA: 170 MW Gas UOG: 352 MW
SCE [C]	2013	1,615–2,090 MW	> 800 bids, 66 bidders (Western Basin)	EE agreement: 136 MW DR agreement: 75 MW BTM storage agreement: 161 MW BTM renewable PPA: 50 MW Storage agreement: 101 MW storage Gas tolling: 1,698 MW
SDG&E [D]	2014	500–800 MW	N/A	EE agreement: 18.5 MW Storage tolling: 20 MW (canceled) Gas tolling: 500 MW
APS [E]	2016	400–600 MW	N/A	Gas tolling: 565 MW
EPE [F]	2017	370 MW	81 bids	Gas combustion turbine (CT) UOG: 226 MW Solar PV PPA: 200 MW Battery storage PPA: 100 MW 50–150 MW of additional wind and solar
PNM [G]	2017	≤ 456 MW	345 bids	N/A
PSCo [H]	2017	≤ 1,114 MW	430 bids, 111,963 MW (ICAP, bids); 238 projects, 58,283 MW (ICAP, projects)	Gas acquisition: 383 MW Wind UOG: 500 MW (acquisition) Wind PPA: 631 MW Solar PV PPA: 707 MW Battery storage PPA: 250 MW
NIPSCO [I]	2018	600 MW	90 bids, 59 projects 13,236 MW (ICAP, bids); 9,446 MW (UCAP, bids)	1,104 MW wind (102 MW joint ownership, 302 MW joint venture build-transfer agreement)
OG&E [J]	2018	≤ 500 MW	94 bids, 26 projects	Coal acquisition: 360 MW
PSE [K]	2018	272 MW	97 proposals	N/A
NV Energy [L]	2019	400–600 MW	N/A	N/A
Vectren South [M]	2019	10–700 MW	N/A	N/A
IPL [N]	2019	200 MW	N/A	N/A
NorthWestern [O]	2020	280 MW	N/A	N/A
PacifiCorp [P]	2020	N/A	N/A	N/A

N/A - not publicly available or not able to locate; ICAP - installed capacity; UCAP - unforced capacity; PPA - power purchase agreement; UOG - utility-owned generation; EE - energy efficiency; DR - demand response; BTM - behind the meter. Several recent solicitations do not have available information because the solicitation was still in process at the time of writing. Tolling agreements refer to arrangements in which the buyer pays the power plant owner for the right to operate the plant.
Data sources: [A]Merrimack Energy Group 2012; [B]RFP need and solicited proposals from PSCo 2013, selected resources from PSCo 2016; [C]RFP need from California PUC 2013, solicited proposals from SCE 2014 and only for the Western Basin (85 percent of need), selected resources from https://www.sce.com/procurement/solicitations/archive/lcr; [D]RFP need from https://www.sdge.com/all-source-2014-rfo, selected resources from SDG&E 2017; [E]RFP need and selected resources from APS 2017; [F]RFP need from EPE 2017, solicited proposals from EPE 2019, selected resources from https://www.epelectric.com/company/news/plans-to-add-hundreds-of-mws-of-solar-energy-battery-storage-by-2023; [G]RFP need and solicited proposals from Nagel 2019; [H]RFP need from PSCo 2017a, solicited proposals from PSCo 2017b, selected resources from Colorado PUC 2018; [I]RFP need from NIPSCO 2018b, solicited proposals from NIPSCO 2018a, selected resources from https://www.nipsco.com/our-company/news-room/news-article/nipsco-announces-addition-of-three-indiana-grown-wind-projects and IURC 2019; [J]RFP need from OG&E 2018, solicited proposals and selected resources from Rose 2018; [K]RFP need: https://www.pse.com/press-release/details/pse-seeks-bids-for-new-energy-resources; [L]RFP need from NV Energy 2019a; [M]RFP need from https://www.vectren.com/irp; [N]RFP need from https://www.iplpower.com/About_IPL/Regulatory/Filings/IRP_2019/Request_for_Proposals/; [O]RFP need from http://www.northwesternenergy.com/our-company/regulatory-environment/2020-request-for-proposals; [P]intent to conduct all-source RFP from https://www.pacificorp.com/suppliers/rfps/all-source-rfp.html.

- *Bundling resources in innovative ways* (see Table 2 and Table 3). Examples include solar or wind plus battery storage, gas plus battery storage, and solar plus wind.

- *Limited participation and selection of demand-side resources*. Some utilities allowed demand-side resources—demand response and in some cases energy efficiency—to participate in all-source solicitations, whereas in other cases utilities acquired demand-side resources through separate processes.[25] Demand-side resources were selected by California utilities (SCE and SDG&E), but in other solicitations (NIPSCO and EPE) participation of demand-side resources was low, and utilities did not select them.[26]

- *Procurement may exceed expected need*. The EPE (2017) and PSCo (2017) solicitations acquired additional resources to take advantage of low-cost bids for solar PV and wind.

Table 2. Bid Prices from PSCo's 2013 and 2017 All-Source Solicitations[27]

2013 All-Source Solicitation		
Resource	**Unit**	**Approximate Price Range ($)**
Dispatchable Capacity	$/kW-mo	3–61
Renewable	$/MWh (all-in)	52–101
Semi-Dispatchable	$/MWh (all-in)	190–220
Production Tax Credit (PTC) - Wind	$/MWh (all-in)	34–72
2017 All-Source Solicitation		
Resource	**Unit**	**Median Price ($)**
Combustion Turbine/IC Engines	$/kW-mo	4.80
Combustion Turbine with Battery Storage	$/kW-mo	6.20
Stand-alone Battery Storage	$/kW-mo	11.30
Wind	$/MWh (bid)	18.10
Wind and Solar	$/MWh (bid)	19.90
Wind with Battery Storage	$/MWh (bid)	21.00
Solar (PV)	$/MWh (bid)	29.50
Wind and Solar and Battery Storage	$/MWh (bid)	30.60
Solar (PV) with Battery Storage	$/MWh (bid)	36.00

Note: All-in prices include the bid price plus PSCo-estimated integration and transmission costs.

Consistent with the trend in Table 2, above, utility ownership of new resources acquired in all-source solicitations has often been for thermal resources. Through the PSCo (2017) and NIPSO (2018) solicitations, both utilities also acquired wind generation either directly or through joint ventures.

Publicized median or average bid prices from the PSCo (2013, 2017) and NIPSCO (2018) solicitations illustrate potential benefits of regular all-source solicitations for price discovery. Bid prices for wind, solar PV, and battery storage declined significantly in the four years between PSCo solicitations (Table 2).

[25] Solicitations where demand-side resources were allowed to participate include SCE 2013; SDG&E 2014; EPE 2017; and NIPSCO 2018. PSE conducted a separate solicitation in 2018 for demand response. PSCo did not accept demand-side resources in either of its solicitations, consistent with the Colorado PUC's decision to acquire these resources through a separate proceeding. When acquired through a separate process, demand-side resources reduce needs in the all-source solicitation.
[26] For instance, in the NIPSCO 2018 and EPE 2017 solicitations, the only demand-side resource bid in each was a single demand response bid. See NIPSCO (2018a) and EPE (2019).
[27] PSCo (2017b).

NIPSCO's 2018 all-source solicitation explicitly sought to discover prices.[28] A screening study commissioned by NIPSCO as part of its 2016 Integrated Resource Plan (IRP) found a wide range in technology cost estimates (upper portion of Table 3). In its 2018 solicitation, average bid prices were at the low end, and were in some cases lower than the "minimum" estimates from the screening study (lower portion of Table 3).

Table 3. NIPSCO's Technology Cost Range Estimates and Average Bid Prices[29]

Range of Technology Cost Estimates Based on a Screen Conducted for NIPSCO's 2016 IRP

	Units	Min ($)	Average ($)	Max ($)
Combined cycle gas turbine (CCGT	$/kW	900	1,113	1,326
CT	$/kW	583	834	1,485
Solar PV (utility-scale)	$/kW	1,115	1,673	2,370
Onshore wind	$/kW	1,425	1,719	1,977
Storage (Li-ion, 4-hour)	$/kW	1,317	2,110	3,114

Note: kW - kilowatt

Summary of Average Bid Prices from NIPSCO's 2018 All-Source Competitive Solicitation

	Units	Average Bid Price ($)
Asset Sale or Option		
CCGT	$/kW	959.61
Solar	$/kW	1,151.01
Wind	$/kW	1,457.07
Solar + Storage	$/kW	1,182.79
Power Purchase Agreement		
CCGT	$/kW-mo + fuel and variable O&M	7.86
Solar + Storage	$/kW-mo + $35/MWh (average)	5.90
Storage	$/kW-mo	11.24
Solar	$/MWh	35.67
Wind	$/MWh	26.97

Notes: O&M - operations and maintenance; MWh - megawatt-hour

The results of recent all-source solicitations highlight their potential to elicit competitive, innovative offers across a range of resources, but also hint at some of their challenges and the importance of good process design. Chapters 2 and 3 discuss these issues.

1.4 Energy Storage: An Emerging Resource

Growing interest in all-source competitive solicitations is being driven, in part, by the increasing competitiveness and expanding role of energy storage.[30] As a category, energy storage includes battery storage, compressed air, flywheels, pumped hydropower, and thermal storage. Several of these technologies have long been evaluated in utility resource plans. In particular, recent interest in energy

[28] NIPSCO (2018a).
[29] Ibid.
[30] The California Public Utilities Code defines an energy storage system as "… commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy." California's definition further establishes characteristics that a system must have and purposes that it must meet to qualify as energy storage. This definition has been used in other legislature contexts, such as Minnesota's SF 3870 (https://www.revisor.mn.gov/bills/bill.php?b=Senate&f=SF3870&ssn=0&y=2017). See California PUC (2010).

storage technologies has been spurred by the increased competitiveness of short- to medium-duration (less than four-hour) battery storage[31] and the potential role of energy storage in solar and wind integration.

This section provides an overview of key considerations for evaluating energy storage in utility all-source competitive solicitations, as context and background for the report. The section focuses mainly on battery systems, but many of the conclusions apply to electrical storage more broadly.

Energy storage is a unique resource. It can function as both a generator and a load, but is "energy-limited" in the sense that it only shifts energy over time and is not a source of energy. Energy storage is typically highly flexible, with the ability to rapidly ramp its output and start-up. By reducing peak loads and congestion, energy storage also can substitute for transmission and distribution infrastructure as a non-wires alternative.

Battery storage typically has a short construction lead time, providing option value to utilities.[32] For instance, a utility with significant load forecast uncertainty three years into the future may find it cost-effective to wait and procure resources with shorter lead times closer to the time of need.[33] Battery systems can be modular, with implications for minimum size requirements in all-source solicitations (see Section 3.4.3). Batteries can be sited almost anywhere in the electricity system, from behind the customer meter to the high voltage transmission system, making them highly versatile.[34]

Battery systems are eligible for accelerated depreciation and investment tax credits. These federal tax incentives are more lucrative when battery systems are paired with renewable energy.[35] Battery systems have been bid into all-source solicitations as stand-alone systems, paired with wind and solar generation, and in one instance (PSCo's 2017 solicitation) paired with a CT (see Section 1.3).[36]

The unique characteristics of energy storage require a different approach to thinking about its value in the context of resource planning and procurement. From a utility perspective, the value of batteries can be grouped into four broad categories: energy price (or cost) arbitrage, ancillary services, capacity, and resilience (Table 4).[37]

[31] *Duration* refers to the average energy storage capacity of a battery. A 10 MW/20 MWh battery will have a maximum charge rate of 10 MW and an average duration of two hours.
[32] The U.S. Energy Information Administration (EIA), for example, assumes a one-year lead time for batteries in the Electricity Market Module of its *Annual Energy Outlook*. See EIA (2020).
[33] For more on utility long-term forecast error in the Western United States, see Carvallo et al. (2019).
[34] U.S. Department of Energy (2020).
[35] Battery systems are eligible for a seven-year modified accelerated cost recovery system (MACRS) if not charged by a renewable energy system, and a five-year MACRS if they are. Battery systems that are charged with renewable energy more than 75 percent but less than 100 percent of the time are eligible for a portion of the investment tax credit (ITC), which declines from 30 percent in 2018 to 10 percent in 2022. Battery systems that are charged with 100 percent renewable energy receive the full ITC. See NREL (2018).
[36] The rationale for pairing with a CT is to improve the CT's performance—for example, by increasing its ramp rate, reducing its heat rate, and reducing the risk of forced outages.
[37] For additional discussion on the value of energy storage, see EPRI (2011); Denholm et al. (2013); Edgette et al. (2013); Chang et al. (2014); Fitzgerald et al. (2015); and Massachusetts Department of Energy Resources (2017).

Table 4. An Overview of Battery Values to Utilities

Value Category		Description
Energy price (cost) arbitrage	Traditional energy price arbitrage	Charging in lower cost periods and discharging in higher cost periods. *Example*: Battery charges during off-peak periods and discharges during on-peak periods.
	Day-ahead and real-time price (cost) arbitrage	Charging or discharging within the day during periods of lower or higher real-time costs, respectively, relative to day-ahead costs. Higher within-day costs may occur as a result of transmission or generator outages, real-time congestion, real-time ramping, and forecast error. *Example*: A battery maintains a non-zero state of charge in the day-ahead time frame and discharges in real time when costs spike during a transmission outage that occurs within the day.
	Congestion management	Charging when the transmission system is uncongested and discharging when it becomes congested. The battery must be located in a congested (higher cost) part of the transmission system. Congestion arbitrage is done automatically through nodal dispatch and locational marginal prices in ISO/RTO markets. *Example*: A battery charges when the transmission system is uncongested and locational marginal costs are $20/MWh, and discharges when it is congested and locational marginal costs are $40/MWh.
	Renewable energy integration	Charging when renewable generation is on the margin, renewable generation is being curtailed, and costs are near-zero or negative, and discharging when fossil-fuel generators are on the margin and marginal costs are higher. *Example*: A battery charges when costs are -$50/MWh and discharges when they are $50/MWh.
Ancillary services	Frequency regulation	Reserving battery capacity and energy to provide upward and downward frequency regulation reserves. Battery energy and ancillary services provision are co-optimized in ISO/RTO markets. *Example*: A 10 MW battery provides 5 MW of energy (discharge) and 5 MW of upward regulation reserve capacity over a five-minute dispatch interval.
	Operating reserves	Reserving battery capacity and energy to provide spinning and non-spinning reserves. Eligibility depends on storage capacity (duration). *Example*: A fully charged 10 MW battery provides 5 MW of energy (average discharge) and 5 MW of spinning reserve capacity over a one-hour interval.
Capacity	System resource adequacy	Reserving battery capacity and energy to provide resource adequacy reserves. The battery's credit toward resource adequacy requirements may be less than its nameplate capacity at higher penetrations of battery storage. *Example*: A 10 MW/40 MWh battery is awarded 9 MW for resource adequacy, based on a capacity credit of 0.9 when four-hour battery storage capacity is equal to 15% of total system peak demand.
	Local resource adequacy	Reserving battery capacity and energy to provide resource adequacy reserves in a transmission-constrained area. *Example*: A battery provides local resource adequacy in a transmission-constrained urban area.
	Distribution	Deferring or avoiding distribution costs by discharging during distribution peak demand periods (Chapter 4). *Example*: A battery defers distribution capital expenditures by discharging during a local peak on a distribution feeder.
	Transmission	For distribution-connected batteries, discharging during transmission peak demand periods, thereby reducing transmission load and net

		transmission costs. In ISO/RTO markets, the net benefits to the utility, if it owns the transmission line, are the difference between the utility's transmission costs and ISO/RTO transmission charge. *Example*: A 10 MW distribution-connected battery reduces utility transmission charges by 10 MW × (transmission charge – unit transmission costs) by discharging during coincident peaks.[38]
Reliability and resilience	Backup generation	Supplying standby power to reduce the frequency and duration of customer outages lasting up to several hours, providing reliability value. Batteries also can reduce the number of longer-duration outages, providing resilience value. *Example*: A battery provides backup power (reliability value) to an islanded part of the distribution system during a two-hour transmission outage.

Notes: The term "costs" in the table refers to unit costs and includes prices in ISO/RTO markets, where relevant. The examples are illustrative and not all inclusive.

Energy storage can, in principle, provide multiple values simultaneously, though in practice its value is limited by charge/discharge capacity and storage capacity. For instance, a 10 MW battery could provide 3 MW of energy, 3 MW of upward regulation reserves, and 4 MW of system resource adequacy reserves, but its provision of energy and reserves cannot exceed the battery's 10 MW discharge capacity.[39] If a distribution-connected battery discharges during the system peak, it also may provide transmission and distribution capacity benefits. In addition, the battery's value is limited by its state of charge. A battery with a zero state of charge cannot discharge energy or provide upward regulation or operating reserves but can provide downward regulation by charging.

Centrally organized wholesale electricity markets provide tools to help utilities maximize the value of storage resources. These tools include locational marginal price-based day-ahead markets and real-time energy markets with five-minute security-constrained economic dispatch,[40] which enable storage to be efficiently used in congestion management and arbitraging day-ahead and real-time price differences. ISOs/RTOs co-optimize procurement of energy and ancillary services, enabling storage capacity to be most efficiently used to provide energy or reserves.

Energy, ancillary services, and resource adequacy values often are more transparent in ISO/RTO markets than in regions without organized markets. Unlike ISOs/RTOs, utilities do not provide developers with sub-hourly, node-specific, day-ahead, and real-time energy and ancillary services prices (marginal costs) and regional long-term transmission plans.[41] Storage and other resource developers can use market prices and regional transmission plans to better customize their projects. ISO/RTO market prices also provide greater transparency of some values that are not well-reflected in standard utility planning tools, such as real-time dispatch, congestion management, regional market participation, and zonal (local) resource adequacy (Section 3.5.4).[42]

[38] For areas outside ISO/RTO regions, the equivalent calculation would use marginal transmission costs, which would be low when the system is unconstrained.
[39] This example is simplified and only intended for illustration. It does not consider, for instance, discharge losses.
[40] Security-constrained economic dispatch is defined as "an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system." U.S. DOE (2007), 3.
[41] In areas without centrally organized wholesale electricity markets, utilities typically provide bidders in competitive solicitations with information on utilities' high-level costs through their resource plans and may provide bidders with information on available transmission capacity. Utilities may limit the amount of information they provide to developers to gain a competitive advantage.
[42] *Zonal* (or *local*) resource adequacy refers to resource adequacy requirements for individual zones within a balancing area that result from transmission constraints. Zonal resource adequacy requirements establish a minimum amount of capacity resources that must be procured within that zone, to ensure resource adequacy even if the transmission system is constrained.

Because all-source solicitations are typically developed around the utility's capacity needs (Section 3.3), resource adequacy considerations are pivotal for the competitiveness of energy storage in these solicitations. Two key considerations are how storage is counted toward resource adequacy requirements and how local resource adequacy values are evaluated. As an energy-limited resource, the capacity credit for storage often is less than its nameplate capacity. Further, its capacity credit may decline as more storage comes online. Methods for calculating the capacity credit of storage today vary across ISOs/RTOs and utilities, but may eventually converge on effective load carrying capability (ELCC) (Section 3.5.4). Energy storage may be easier to site than generation and thus has high value in congested load pockets.[43] Capturing local resource adequacy value is important for storage economics.

As a capacity resource, energy storage is often compared with a CT, either explicitly or implicitly through portfolio optimization. The two resources can be compared in terms of their annualized ($/kW-yr) capacity costs. While a CT often sits idle because of its high operating costs, energy storage can provide energy and ancillary service value throughout the year. In comparing the two resources, it is thus important to compare their net capacity costs, or equivalently the net value that they provide. Net value is the market value and other benefits of a resource minus its costs (see Section 3.5.3). Energy storage can be cost-effective for filling a capacity need even if its annualized costs are higher than a CT.

In general, the value of energy storage for providing different forms of energy arbitrage depends on the frequency and duration of arbitrage events, such as wind and solar curtailment (low or negative prices), transmission congestion, or real-time price spikes.[44] For instance, a $5/MWh average net price spread over half of the hours in a year (4,380) will have more than double the value ($22/kW-yr) of a $100/MWh average price spread in 100 hours per year ($10/kW-yr). This implies that storage will have more limited value for integration of renewable resources, congestion management, and real-time dispatch if the frequency and duration of wind and solar curtailment, transmission congestion, and real-time price spikes are relatively low.

When paired with other resources, the cost of battery storage can be difficult to interpret. For instance, in PSCo's 2017 solicitation, the median bid price for wind was $18.10/MWh and the median bid price for wind with battery storage was $21.00/MWh, but this does not imply that the levelized cost of battery storage is $2.90/MWh. The megawatt-hours in the denominator are mostly or entirely for wind generation, and it is not clear from the bid price how much storage (MW or MWh) was included in the bid.[45] More important, these bid prices provide limited information on the *value* of paired storage, as storage plus wind or solar may have tax incentive-related restrictions on when it can charge. Like other resources, the most appropriate way to evaluate paired battery storage, and assess its merits relative to stand-alone storage, is by calculating its net value (benefits minus costs) to the utility.

Cycling costs are an important and often overlooked consideration for battery evaluation.[46] More frequent charging and discharging (cycling) batteries will reduce their operating lifetimes. Restricting battery operation, however, may lead to lost value. This trade-off has important implications for contracting. For instance, power purchase agreements that are denominated in terms of net megawatt-hours discharged

[43] Siting battery storage in urban areas may require upgrades in safety codes to address fire safety concerns and may benefit from more streamlined permitting. Even so, batteries have a smaller footprint and may be able to comply more easily with environmental requirements than a thermal generator. See GAO (2018).

[44] This assumes that the scarcity value of storage is considered a capacity (resource adequacy) value rather than an energy arbitrage value.

[45] For instance, consider a bid for a 100 MW, 30 percent capacity factor wind facility with costs of $50/kW-yr that is paired with 5 MW of storage at $120/kW-yr. The annual energy cost of the wind facility will be $19/MWh ($50/kW-yr / [100 MW × 0.3 × 8,760 hrs/yr]). The combined annual cost of the wind and battery facility will be $5.6 million/yr ($50/kW-yr × 100 MW + $120/kW-yr × 5 MW), and its annual energy cost, per unit of wind generation, will be $21/MWh ($5.6 million/yr / [100 MW × 0.3 × 8,760 hrs/yr]). The approximately $2/MWh cost difference between the two tells little about the cost or size of the battery, unless one of these characteristics and the cost and capacity factor of the paired resource are known.

[46] Xu et al. (2018).

from the battery explicitly incorporate cycling costs. In fixed price contracts, which allow utilities to operate the battery for an annual fixed ($/kW-yr) payment, bidders must include an estimate of cycling costs in their fixed price bids and may set limits on cycling in the negotiated contract with the utility (or aggregator).

Because of unique operating characteristics, rigorous evaluation of energy storage bids is important for determining whether they are cost-effective and what kinds of bids and contracting options provide the most net value for utilities.[47] Additional considerations for including and evaluating energy storage in all-source solicitations are discussed in later sections of this report.

[47] The Electric Power Research Institute (EPRI) offers guides, tools, and templates for energy storage implementation, including RFPs, at EPRI Energy Storage Integration Council (ESIC), https://www.epri.com/#/pages/sa/epri-energy-storage-integration-council-esic?lang=en-US.

2.0 Overview of All-Source Competitive Solicitations

This chapter focuses on three areas of all-source competitive solicitations:

- Goals, principles, and the importance of a good process
- Design trade-offs
- Process stages

2.1 Goals, Principles, and the Importance of Good Process

Generally, the goals of all-source competitive procurement of electricity resources are competitive pricing and innovative proposals across a diverse range of resources, resulting in lower costs for utility customers over time, fair returns for utilities and non-utility suppliers, and fair allocation of risk among all parties.

As a regulated process with a monopsony[48] utility buyer, the ability of competitive solicitations to achieve these goals rests on utilities treating all proposals objectively and impartially. Utilities or their affiliates often are permitted, and in some cases the utility has been required, to participate in competitive solicitations directly, by proposing projects or partnering with developers, and indirectly by soliciting projects for utility ownership or eventual transfer to utility ownership.[49] When utilities participate in competitive solicitations as both the sole buyer and a potential seller, opportunities for self-dealing raise concerns around impartiality.

These concerns have a long history. Questions over how to regulate utilities' transactions with their affiliates emerged as utilities began to undertake competitive solicitations in the late 1980s. At the time, regulators had limited ability to detect and confirm affiliate abuse.[50] To govern utilities' transactions with their affiliates, FERC established three criteria in *Edgar* (1991) that would demonstrate lack of affiliate abuse:

> *"(1) a competitive solicitation process was designed and implemented without undue preference for an affiliate; (2) the analysis of bids did not favor affiliates, particularly with respect to non-price factors; and (3) the affiliate was selected based on some reasonable combination of price and non-price factors."*[51]

Later, in *Allegheny* (2004) and *Ameren* (2004), FERC developed four principles to determine whether an RFP meets the *Edgar* criteria:

> *"a. Transparency: the competitive solicitation process should be open and fair;*
>
> *b. Definition: the product or products sought through the competitive solicitation should be precisely defined;*

[48] A monopsony is "a market with many sellers but only one buyer." Pindyck and Rubinfeld (2001), 327.
[49] Tierney and Shatzki (2008). The rationale for allowing utilities to participate in competitive solicitations has historically been that, because of their expertise, knowledge of their systems, or low cost of capital utilities may be able to provide cost-effective resource solutions. See, for instance, Rose et al. (1991).
[50] Harunuzzaman and Costello (1996).
[51] FERC (2004a).

c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders;

d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection."[52]

These four principles provide a high-level regulatory framework for ensuring fairness in competitive procurement.[53] However, fairness considerations extend beyond treatment of transparency, product definition, evaluation criteria, and oversight. For instance, what is a reasonable timeline for the solicitation process and how long should bidders be required to maintain the validity of their bids? How should utilities incorporate and weight non-price considerations? How can utilities have greater certainty that PUCs will allow cost recovery in utility customer rates for the resources utilities select in competitive solicitations? How can bidders ensure redress in the event of disputes with utilities? How can bidders ensure that utility contracts will fairly allocate risks?

These broader concerns highlight the importance of good process design and implementation for maintaining fairness in competitive solicitations. Whether state regulators play more active or responsive roles in designing the solicitation process, their oversight is critical for building confidence in the integrity of the process.[54] Confidence in the integrity of the process, in turn, is important for encouraging greater participation and more competitive and innovative offers. Chapter 3 explores process design and implementation options and issues for all-source competitive solicitations.

2.2 Design Trade-offs

Like competitive solicitations broadly, the design of all-source solicitation processes involves several trade-offs, described below.[55]

- *Regulatory prescriptiveness versus utility flexibility*. More prescriptive rules on how utilities should design and implement competitive solicitations can assuage concerns over utility self-dealing or utilities' incentives to manage costs but may limit utilities' flexibility to find low-cost, low-risk, high-value solutions. More prescriptive requirements on how winning bids are treated can increase developer confidence, but may not provide sufficient flexibility to course-correct if issues arise during contracting.

- *More versus less transparent process for stakeholders*. Enabling stakeholders to review RFP documents, evaluation methods, and selection results may improve the integrity of the process and increase buy-in for the results but may slow the process and create concerns over the confidentiality of bidders' and utilities' commercially sensitive information.[56]

- *More versus less information on evaluation criteria and methods revealed to bidders*. Providing more information to bidders on evaluation methods and criteria increases transparency, the likelihood of suitable bids, and fairness but reduces the utility's discretion

[52] FERC (2004a); FERC (2004b).
[53] FERC's regulation of affiliate transactions was intended to complement state regulatory review of competitive solicitations (Strunk and Patel 2004). FERC continues to authorize affiliate transactions, though notably it has not required third-party design and implementation of solicitations as a condition for meeting the *Edgar* criteria. For a recent example of FERC's review and approval of an affiliate transaction in an all-source solicitation (NIPSCO and Rosewater Wind Farm, LLC), see FERC (2019).
[54] Tierney and Shatzki (2008).
[55] For historical perspective on these trade-offs, see Rose et al. (1991) and Tierney and Shatzki (2008).
[56] Strategies for addressing confidentiality concerns are discussed in Section 3.4.5.

in evaluating bids and increases the chances that bidders will focus on maximizing their scores rather than developing innovative projects.

- *Longer versus shorter solicitation timeline*. A longer timeline allows more time for bidders to develop projects, for utilities to evaluate bids, and for regulatory review. But it increases solicitation costs and increases risks for developers (which have to maintain the validity of their bids throughout the process) and utilities (which may have near-term resource needs).

- *Stricter versus more relaxed bidder requirements*. More relaxed requirements may encourage greater participation and competition, but lower bidder eligibility. Collateral requirements increase risks for utilities, which may not be able to pass on to customers the costs of construction delays or operational under-performance.[57] Ratepayers may be forced to absorb the cost of failed projects. Failed projects may decrease confidence by stakeholders in the solicitation process. Stricter requirements may favor more traditional, well-capitalized firms and incumbents.

The use of independent evaluators, described in more detail in Section 3.6, is key to addressing many of these trade-offs. PUCs also can improve their management of trade-offs by periodically reviewing the solicitation process and outcomes. Independent evaluators can help conduct this review and recommend improvements to the solicitation process as part of their evaluations for each solicitation. PUCs and utilities can make ongoing refinements to solicitations based on these reviews.

The use of all-source solicitations is itself a decision regarding another important trade-off. They provide utilities with the flexibility to develop an optimal resource portfolio by evaluating bids from a range of different resource types and ownership structures. This greater flexibility may enable more innovative solutions and allows utilities to respond to bids and changes in market conditions. At the same time, all-source solicitations require a significant amount of trust in the utility bid evaluation and selection process, including utility modeling, to fairly evaluate resources with diverse operating characteristics and ownership structures. Also, such solicitations often seek more types of products. Thus, having professional independent evaluators that monitor the process and review and verify outcomes is even more critical for all-source solicitations than limited-source solicitations—solicitations in which the scope of procurement is deliberately constrained to a narrowly defined resource type.

Design trade-offs in competitive solicitations are complex and require regulatory judgment. Different jurisdictions will reasonably make different trade-offs. Chapter 3 describes design options and issues for addressing trade-offs in the context of recent all-source competitive solicitations.

2.3 Process Stages

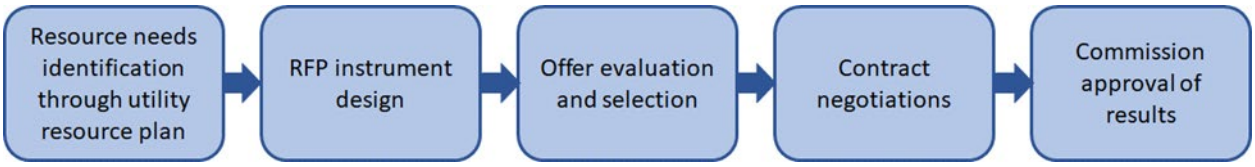
Competitive all-source procurement processes generally include five main stages, illustrated in Figure 3.[58] Needs identification, described in Section 3.3, typically is undertaken through utility resource planning. During RFP instrument design (Section 3.4), utilities and PUCs develop the process for soliciting offers, including timelines, documents, pre-qualification requirements, communication protocols, and evaluation

[57] For instance, low development securities may mean that developers do not have sufficient incentives to meet construction milestones, potentially leading to delays in bringing projects online. If utilities are forced to pay high market prices to meet energy or capacity needs due to these delays, regulators may disallow a portion of these costs.

[58] Characterizations of utility competitive procurement processes vary. For instance, Rose et al. (1991) identify five stages in the procurement process: solicitation, evaluation, selection, negotiation, and contracting. Tierney and Shatzki (2008) identify seven components in procurement designs: identify need, design RFP instrument, receive bids, evaluate offers and select winning offer, inform bidders and regulators, negotiate contracts, and submit results for commission approval.

criteria. Evaluation and selection, described in Section 3.5, are a focal area in all-source solicitations because of the diverse nature of offers. The final stages are contract negotiation and, in some states, PUC approval of the results.

Figure 3. Main Stages in All-Source Competitive Procurement



All-source solicitations are normally governed by PUC rules and guidelines that shape when utilities use competitive procurement, timelines and deadlines for the procurement process, requirements for RFP documents, and evaluation procedures and methods (Section 3.1). Commission rules also stipulate requirements for independent evaluators (Section 3.6) and opportunities for stakeholder review.

Ultimately, regulatory approval is required to include in utility customer rates the costs of resources that utilities acquire through competitive solicitations. States take different approaches as to what PUCs approve in utility competitive solicitation processes and when (e.g., the RFP instrument, a short-list of bids prior to contract negotiation, and the final selections), the role of the PUC overseeing contracting, and how and when PUC determinations of prudence are made. This report does not provide in-depth treatment of these topics.[59]

[59] For more on these topics, see Tierney and Shatzki (2008) and Lazar (2016).

3.0 Design and Implementation Options for Bulk Power Systems

This chapter discusses design and implementation options and issues for all-source competitive solicitations for bulk power systems, covering:

- Procurement rules and guidance
- Interaction between resource planning and all-source procurement
- Needs identification
- RFP instrument design
- Evaluation and selection
- Independent evaluation

The North American Electric Reliability Corporation (NERC) defines the bulk power system to include power-producing resources that aggregate to a total capacity greater than 75 megavolt amperes (MVA)[60] and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This does not include facilities used in the local distribution of electric energy.[61] Functional definitions of the bulk power system vary among states.

3.1 Procurement Rules and Guidance

Legislative requirements and regulatory rules and guidance[62] provide both the impetus for, and the conditions that shape, all-source competitive solicitations. All utilities that recently conducted all-source solicitations have, at a minimum, a statutory or PUC requirement to use a competitive process to acquire new resources. For some utilities, the use of *all-source* procurement is voluntary, whereas for others it is a requirement,[63] as in the case under Colorado's *Rules Regulating Electric Utilities*:

> *"3611 - 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)."*[64]

State PUCs generally allow utilities flexibility to bypass all-source competitive procurement under extenuating circumstances, including emergency situations and unusual economic opportunities. However, the burden is on utilities to demonstrate that doing so would serve the public interest.[65]

[60] MVA is the unit for apparent power. Apparent power is the sum of real and reactive power.
[61] NERC (n.d.).
[62] In principle, rules are binding while guidance is not (Tierney and Shatzki 2008). In practice, because following guidelines will reduce the risk of cost disallowance for utilities, differences between the two are subtle.
[63] NIPSCO's 2018 solicitation is an example of voluntary use of all-source procurement.
[64] Colorado PUC (2019), 89.
[65] The public interest may range from emergencies to economic considerations. As an example, Colorado's *Rules Regulating Electric Utilities* allow utilities to propose an alternative to all-source competitive procurement, but require that the utility "… shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate

Broadly, procurement rules and guidelines may cover participation by bidders and utilities; minimum requirements for the RFP process, including evaluation criteria and process; timing and scope of commission and stakeholder review; and use of independent evaluators. PUCs take diverse approaches to the design and detail of procurement rules and guidelines, on a spectrum from prescriptive and detailed, on one extreme, to indicative and parsimonious on the other.[66]

3.2 Interaction Between Resource Planning and All-Source Procurement

Resource planning and all-source competitive procurement focus on different time horizons. Resource planning provides a long-term (for instance, 20-year) view of demand, comparative resource options, risks, and the utility's preferred course of action.[67] Through procurement, the utility acquires both short-term and long-term resources to meet resource needs that typically begin over the next one to five years.

Planning and procurement are interactive. Resource needs are first identified in resource plans, based on forecasts of load growth, policy compliance requirements, planned generator retirements, and expiration of power purchase agreements. Evaluation and selection of resources in all-source solicitations ideally should be consistent with the utility's assessment in its resource plan of long-term costs and risks, updated in time. The utility also can use the results of its all-source solicitations to inform cost assumptions in its next resource plan. For instance, NIPSCO used its 2018 all-source solicitation to inform its 2018 IRP update; the resource need used in this solicitation was based on its 2016 IRP.[68]

The design of this interaction varies among jurisdictions. In most states, resource planning and competitive procurement are effectively separate processes that have points of intersection. Utilities use resource planning to determine resource needs. They may use consistent model inputs and assumptions, and in some cases scenarios, from resource planning in evaluating bids in the solicitation, to assist participants in developing their bids.[69] Utilities select resources based on the evaluation and, where required or allowed, apply for certificates of public convenience and necessity (CPCN) or PUC approval of contracts.

In a few states, planning and procurement are combined in a single unified regulatory process. Colorado is illustrative of this approach. Its electricity resource planning (ERP) process includes two phases. In phase one, utilities develop scenario-based (baseline and alternative) least-cost plans, identify near-term resource needs, and describe evaluation methods for the RFP (see Section 3.5). The Colorado Public Utilities Commission approves planning assumptions and methods, draft RFP documents, and

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the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition." See Colorado PUC (2019), 89. Time-limited opportunities are another potential reason that competitive bidding requirements include a process for consideration of exemptions—for example, in cases when an existing resource owned by an unaffiliated entity or an expiring power purchase agreement become available.

[66] For a historical perspective, see Rose et al. (1991) and Kahn et al. (1989).

[67] Kahrl et al. (2016).

[68] NIPSCO (2018a, 2018b).

[69] Using consistent inputs and assumptions does not imply rigidly maintaining identical inputs and assumptions, as conditions may change between the time of the resource plan and the time of the solicitation. For a review, see Carvallo et al. (2019). OG&E provides an example application. In its 2018 all-source RFP, OG&E notes that it will "… evaluate all bids based on the expected customer impact resulting from detailed simulation modeling and sensitivity analysis consideration as performed in the OG&E IRP" and that the "… modeling application will be consistent with the analysis and tools described in OG&E's 2018 IRP filing, including stress test analysis on customer cost." It further clarifies that, "Detailed assumptions used within the model are available in the OG&E IRP.... Bidders are responsible to review OG&E's IRP and consider IRP assumptions and results in designing their bid." See OG&E (2018), 14–15.

independent evaluators. In phase two, utilities conduct the solicitation, evaluate and select resources, and the Commission approves, conditions, modifies, or rejects the proposed resource plan.[70]

In practice, differences between these "unified" and "separate" approaches are subtle. The unified approach can, in principle, enable more structured PUC and stakeholder review throughout the planning and procurement process and greater consistency between resource planning and procurement. Under the separate approach, however, planning and procurement processes also can be designed to interact like a single unified process.

Regardless of approach, the timing of all-source competitive solicitations is typically tied to resource planning timelines. In some cases, however, PUCs give utilities flexibility to conduct an all-source solicitation in response to changing market or regulatory conditions, rather than according to a preset schedule.[71]

3.3 Needs Identification

Needs identification is the process through which utilities determine the characteristics of the need utilities seek to fill through the solicitation, in terms of amount, timing, and possibly location. As described in the previous section, utilities typically determine need through resource planning.

In all-source solicitations, needs are distinct from products. Needs can be defined in terms of the capacity, energy, reserves, and resource attributes needed to meet procurement mandates.[72] Products are types of resources sought through the solicitation, such as dispatchable and non-dispatchable resources (see Section 3.4.4).

A defining feature of all-source solicitations is that need is broadly defined, to allow a range of resources to compete to fill the need. In contrast, in limited-source solicitations utilities more narrowly define need in terms of function (peaking, intermediate, baseload) or specific resources determined through resource plans or policy compliance plans.

For all-source solicitations, need is typically expressed in terms of firm (unforced) capacity, as capacity need often is the binding constraint, and capacity factors of different kinds of resources providing firm capacity vary.[73] In every all-source solicitation in Table 1, utilities specified need only in terms of firm capacity, even in cases where they were replacing a large amount of energy from retiring natural gas-fired (SCE 2013 solicitation) and coal-fired (PSCo 2017 solicitation) units. All resources, including wind and solar generation, can provide some amount of firm capacity (Section 1.3, 3.5.3).

Load forecasting has always been a challenge for utilities in identifying their resource needs. These challenges have become more complex over the past decade due to the emergence of lower cost distributed generation and battery storage and utility customers' growing desire for choice. Some states have responded by allowing utilities to develop market-based options for customers, as a complement to bulk power resource procurement (see text box).

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[70] Reasoner (2009); Colorado PUC (2018).
[71] NIPSCO's 2018 all-source solicitation provides an example of this kind of flexibility.
[72] Some utilities may identify additional reserve needs to integrate solar and wind generation (flexibility reserves), but utilities typically do not identify regulation and operating reserves separately from capacity. *Resource attribute* here refers primarily to renewable energy attributes.
[73] As long as the solicitation has a reasonably large number of project proposals from diverse resources, energy demand should not be a binding constraint. In other words, through a solicitation that procures incremental capacity needs, utilities also meet their incremental energy needs.

Market-Based Options for Utility Customers

Competitive procurement is a market-based solution for utility acquisition of resources, but it does not directly provide customers with access to markets for either utility-scale generation or DER services from third-party aggregators.

To provide market access while continuing to serve customers in vertically integrated states, utilities can:

1. Allow customers to solicit and choose offers from non-utility suppliers
2. Solicit offers from suppliers on behalf of or jointly with customers, allowing for tailored solutions
3. Solicit offers from suppliers for dedicated programs that customers can participate in
4. Provide customers with access to market-based rates, allowing them to sign virtual contracts

In the first three options, the utility signs the contract with the supplier and serves the customer on a cost-based tariff that reflects the utility's costs of servicing the customer under the contract, including imbalance and ancillary service, transmission, distribution, and administrative costs. In options 1 and 2, contracts are often referred to as "sleeved" because they are wrapped with utility tariffs. Examples of utility tariffs that facilitate sleeved contracts include Rocky Mountain Power's Schedule 34, NV Energy's Green Energy Rider, and Kentucky Power's Renewable Power Option Rider.

In the third case, utilities can provide subscription-based tariffs that provide customers with flexibility in terms of the level and duration with which they wish to participate in the program. Examples of subscription-based tariffs include Puget Sound Energy's Green Direct program, Xcel Energy's Renewable*Connect program, and Georgia Power's Renewable Development Initiative. Some tariffs, such as the Green Energy Rider, allow for different mechanisms (options 1, 2, and 3) for solicitations and contracting.

Although these kinds of tariff programs have focused on facilitating access to markets for utility-scale renewable resources, they also can facilitate access to markets for DER services. To enable third-party DER aggregators to competitively provide services for utility customers, PUCs may need to address utility incentives, wholesale market access issues for DERs, contracting obstacles for DER providers, and tariff structures for DER aggregators.

For further reading on market-based options for utility customers, see Bonugli 2019; for more on removing obstacles for DER providers, see Migden-Ostrander et al. 2018.

Utilities generally take one of two approaches to incorporating into all-source solicitations their needs for policy-driven resources, such as renewable resource requirements or energy storage mandates. In the first approach, utilities include policy-driven resource needs as minimum procurement amounts. PSCo's 2017 all-source solicitation provides an example of this approach. The utility considered including renewable and flexible resource needs in its RFP in part to comply with Colorado's renewable energy standard and meet its flexible reserve requirements.[74]

In the second approach, utilities have separate, dedicated procurement processes for policy-driven resources. In the all-source solicitation, they may procure some or all of their policy resource needs, and then procure the residual amount needed in a dedicated procurement process. SCE's 2013 all-source solicitation for local capacity requirements (LCR) resources is an example of this approach. In this solicitation, SCE procured some renewable and energy storage resources that could be applied to its RPS and energy storage mandate compliance needs.[75] Any residual amounts were procured in dedicated RPS and energy storage procurement. Both approaches allow the utility to procure in amounts beyond the minimum requirements, if cost-effective.

[74] PSCo determined that it was ahead of schedule to meet Renewable Energy Standard targets and that no additional resources were needed to provide flexible reserves. See PSCo (2016a).
[75] For a discussion of interactions among these procurement processes, see SCE (2013a).

Utilities can integrate the evaluation of generator retirement decisions with the evaluation of new all-source solicitations. A utility, for instance, may have older generation facilities that have relatively high going-forward costs and could be mothballed or retired if solicited bids are low enough, even in cases where there is remaining book (undepreciated) value in the existing generation asset. PSCo's 2017 solicitation provides an illustration of such an instance. The utility included the capacity of two coal units in the upper end of its resource need range. With low cost bids available in the solicitation, PSCo decided to retire both units.[76]

Need is often a flexible target—utilities often do not procure the exact amount of firm capacity or other need announced in the RFP. A utility may decide to procure less than its RFP need and use short-term market purchases to make up any near-term shortfalls before its next procurement cycle.[77] A utility also may decide to procure more than its RFP need, if bids have lower than anticipated costs.[78]

3.4 RFP Instrument Design

3.4.1 Documents and Information for Bidders

Like utility RFPs broadly, all-source RFPs typically include a core set of materials and information:

- *RFP document*, which describes the purpose of the RFP, contact information and communication protocols, schedule, bidder requirements, proposal submission guidelines and requirements, technology requirements, proposal fees, credit requirements, confidentiality rules, evaluation process, regulatory approval process, and other terms and conditions associated with the RFP
- *Notice of intent to bid*, which solicits information on the bidder company, proposed resource type, and proposed interconnection point
- *Model contracts or term sheets*, which establish default terms and conditions for contracts and basis for contract negotiations
- *Evaluation criteria*, which describe, in greater detail than the RFP document, how utilities will evaluate bids

RFP documents also may reference or include the utility's resource plan that is associated with the RFP.

To support a competitive all-source solicitation, the information provided through RFP documents must be sufficiently comprehensive to enable a significant number of bidders with potentially diverse projects to develop bids that will meet eligibility requirements and advance to final evaluation. Bidders also must have clarity on their risks, which entails transparency on bid validity requirements, technology performance requirements, security requirements, and contract terms and conditions. Rules and a process for dispute resolution—for instance, related to evaluation or contract negotiations—also can engender confidence in the solicitation process.[79]

[76] Colorado PUC (2018).
[77] For example, see NIPSCO's 2018 solicitation, Table 1 and NIPSCO (2018a).
[78] For example, see EPE's 2017 solicitation (Table 1).
[79] For instance, the EPE 2017 and PSCo 2017 RFPs created a process through which bidders can petition to change how their bids are being treated in the evaluation process.

In some cases, PUC rules stipulate what type of information should be included in the RFP.[80] In other cases, ensuring that the RFP documents contain sufficient information for a fair and competitive process is the job of the independent evaluator. Any adjustments to RFP documents once they are released, including changes in modeling inputs and assumptions in cases where the utility is carrying out the evaluation, typically are done in consultation with the independent evaluator.

Colorado's all-source procurement process is unique in the sense that some of the information typically in RFP documents also is included in utilities' resource plans. This information includes minimum bid size, a description of the evaluation process, modeling inputs and assumptions, and a generic timeline.[81]

3.4.2 Process and Timeline

All-source RFP processes generally contain five elements:

- Bidders conference and question and answer period
- Notice of intent to bid
- Proposal submission
- Evaluation and selection
- Contract execution

The processes, milestones, and timelines for all-source solicitations vary significantly among utilities due to different solicitation designs and regulatory requirements (Table 5). Colorado's (PSCo in Table 5) process and timeline, for instance, are set through commission rules.[82] In other cases, commissions may set requirements only for specific milestones, such as responding to proposals and contract execution.

[80] For instance, New Mexico's proposed procurement requirements specify that the RFP should include: "(1) bid evaluation criteria and bid ranking; (2) the overall amount and duration of power the utility is soliciting and any other details concerning its resource needs; (3) reasonable estimates of transmission costs for resources, if relevant, including a detailed description of how the costs of future transmission will likely apply to bid resources; (4) the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; (5) the utility's proposed contracts for the acquisition of resources; (6) proposed contract term lengths; (7) the discount rate; (8) modeling inputs and assumption as well as general planning assumptions; (9) the timing of process, including the solicitation period, the ranking period and the expected selection period; (10) all security requirements and the rationale behind them;
(11) any bidder's notice of communication or non-communication with any commissioner during the blackout period; (12) a requirement that the utility cannot unreasonably discriminate between proposals for a utility-owned resource and proposals for a resource owned by an independent power producer through a purchase power agreement; and (13) any other information necessary to implement a competitive procurement process." See NMAC (n.d.).
[81] PSCo (2016a, 2016b).
[82] Colorado PUC (2018).

Table 5. Expected RFP Timelines for All-Source Solicitations, in Days from RFP Issue[83]

EPE (2017)	
Activity	**Days**
Pre-bid meeting	19
Notice of intent to bid due	35
Final submission of questions	56
Response to questions	75
Proposal and fee due	96
Shortlist notification	250
Individual meetings complete	262
Best and final proposal due	278
Contract execution	366

NIPSCO (2018)	
Activity	**Days**
Pre-bid conference	2
Notice of intent, pre-qualification application due	15
Notification of pre-qualification application results	21
Proposal due	46
Proposal evaluation complete	123
Agreements executed	231

PSCo (2017)	
Activity	**Days**
Pre-bid meeting and RFP Q&A	29
Notice of intent to respond	30
Bid receipt	90
30-day report due	120
Bidder advancement notification	135
120-day report due	210
Independent evaluator RFP analysis report due	240
Intervenor's comments due	255
Company comments due	270
Commission decision	300
Completion of acquisition	630

OG&E (2018)	
Activity	**Days**
RFP technical conference	-3
Final submission of questions	7
OG&E response to questions	9
Notice of intent to bid due	10
Proposal and fee due	14
Selection of projects for negotiation	29
Complete negotiations	43

Note: A negative sign indicates that the activity occurred before RFP issue.

All-source procurements are, by nature, more complex than limited-source procurements because they involve a diverse range of technologies, resource combinations, and ownership structures. This greater complexity accentuates the trade-off between the timing needed for strong and diverse bids, robust evaluation of those bids, and commission and stakeholder review, on the one hand, and the impact of a longer process on bid validity and solicitation cost, on the other hand. PUCs and utilities use judgment and ongoing adaptation of solicitation design to resolve these trade-offs.

3.4.3 Eligibility Requirements

Utilities require bidders to meet a variety of eligibility requirements in order to have their proposals pass to the evaluation stage (Table 6). In some cases, these requirements reflect utility preferences; in other cases, they are threshold requirements. The most common eligibility requirements are bidder creditworthiness, project deliverability, site control, project minimum size, and commercial operation date (COD). Some eligibility requirements may be resource-specific, whereas others are shared across different resource types. For instance, site control will be required for natural gas generation but not for demand response bids, but both will be required to meet a specified commercial operation date.[84] State or utility eligibility requirements or considerations also may include safety, local material content and labor, minority-owned businesses, brownfield development, dispatchability, and ancillary services needs.

[83] Schedules are from EPE (2017); NIPSCO (2018b); PSCo (2017a); and OG&E (2018).
[84] For an example, see SCE (2013b).

Table 6. Illustrative Eligibility Requirements for All-Source Solicitations[85]

Requirement	Description
Site control	Developer must demonstrate a high level of control[86] over the proposed site
Project location or deliverability	Project must be in or fully deliverable to a specified transmission zone
Development milestone plan	Developer must demonstrate ability to secure permits, agreements, and studies to meet a proposed COD
Fuel supply plan	Developer must demonstrate ability to secure and maintain an adequate fuel supply
Independent units	Generation or storage units must be able to operate independently of other units
Exclusive output and dispatch rights	Utility will have exclusive rights to utilize the resource up to the procured quantity
Minimum project size	Projects must exceed a minimum quantity of installed capacity
Remaining useful life	Project must have a minimum remaining useful life
Minimum operating requirements	Project must meet minimum operating requirements
COD	Project must be able to achieve a COD within a specified time window
Contract duration	Contract duration must be within a specified time window
Proposal structures and terms	Proposals must meet specified terms and conditions and not be conditioned on contingencies
Scheduling provisions	Utility will act as the scheduler for the project in ISO/RTO markets
Company structure	Project developer should be a sole purpose entity
Bidder experience	Bidder should have a minimum number of years of experience with similar projects
Bidder financial ability	Bidder must meet minimum standards for financial strength and creditworthiness

A key difference among utilities in terms of project deliverability requirements is whether the utility participates in a centrally organized wholesale electricity market administered by an ISO or RTO. For utilities that participate in such markets, projects are typically required to secure full deliverability to the capacity zone where the utility serves load, which may require the project to pay the cost of any required incremental transmission upgrades.[87] For utilities that do not participate in these markets, projects are required to secure firm transmission service to the utility's service territory, which may require paying pancaked transmission rates[88] and will tend to discourage projects that are multiple service territories away from the utility.

Some states and utilities allow demand response and, to a lesser extent, energy efficiency to participate in all-source solicitations alongside utility-scale resources to fill firm capacity needs (Section 1.3). Even when these demand-side resources can participate in all-source solicitations, their participation complements but does not replace demand-side programs and procurement.[89] A demand response provider, for instance, can choose to participate in either the all-source solicitation or in programs.

Whether demand-side resources should be procured as part of all-source solicitations or through programs has been debated since the 1980s. Key questions center around economic efficiency and whether demand-side resource projects, and energy efficiency projects in particular, have fundamentally different

[85] Based on SCE (2013b); EPE (2017); PSCo (2017a); NIPSCO (2018b); OG&E (2018).
[86] A high level of control could include an executed land lease, an option to lease, or easements.
[87] These transmission upgrade costs are evaluated and assessed by RTOs/ISOs in system impact studies as part of the interconnection process.
[88] "Rate pancaking, or a pancaked rate, occurs when a transmission customer is charged separate access charges for each utility service territory that the customer's contract path crosses." FERC (2016), 2.
[89] All of the utilities in Table 1 that allowed demand-side resource participation in their all-source solicitations (SCE, SDG&E, EPE, and NIPSCO) also administer demand-side programs.

characteristics that impede their fair participation in all-source competitive bidding.[90] Varying practices across states suggests that these debates have not been resolved.[91]

Under the broader umbrella of DERs, new kinds of distribution-level resources are emerging, including hybrid solar-plus-storage projects and aggregations of distributed generation and battery storage. For instance, in 2019 a 20 MW residential solar-plus-storage project cleared ISO-New England's capacity market. These kinds of DER aggregations have not yet participated in utility all-source competitive solicitations. Like demand response and energy efficiency, there are questions about whether these resources are best procured through all-source competitive bidding or through programs, though in principle the two can be complementary and target different kinds of projects.

Minimum project size is an important consideration in all-source procurements because some kinds of resources—DERs in particular—may have smaller standard sizes. The modularity of battery storage also may lead to smaller project sizes. Minimum size requirements for solicitations and the extent to which they are resource-specific vary by utility (Table 7). For example, PSCo lowered the minimum size requirement in its 2017 all-source solicitation, noting that it "… will allow the Company to determine if the credits afforded to small, supply-side resources interconnecting at distribution voltages can overcome typically lower-cost supplies from larger generation projects employing similar generation technologies."[92]

Table 7. Minimum Size Requirements for Recent All-Source Solicitations[93]

Utility	Solicitation Year	Minimum Size
SCE	2013	Gas-fired units: 25 MW CHP: 1 MW Demand response: 100 kW Energy efficiency: 100 kW Energy storage: 500 kW Distributed generation: 100 kW
EPE	2017	Gas-fired CT: 80 MW Intermittent renewable generation: 5 MW Energy storage: 15 MW, 4-hour duration Demand response: 10 MW
PSCo	2017	100 kW
NIPSCO	2018	Demand response: 10 MW *(no other minimum size requirements specified)*
OG&E	2018	50 MW

3.4.4 Products Solicited

Although all-source competitive solicitations, by definition, are technology and ownership neutral, utilities may solicit offers for specific kinds of products, reflecting the different characteristics,

[90] Concerns over demand-side participation in all-source competitive auctions have included the typical small size of projects, significant customer acquisition costs for service providers, different cost and risk profiles relative to supply-side resources, lack of experience by service providers, measurement issues around peak and efficiency savings, and the often iterative nature of demand-side programs. For an overview of issues around the participation of demand-side resources in all-source competitive solicitations and competitive bidding more generally, see Committee on Energy and Commerce and Subcommittee on Energy and Power (1988); Goldman and Hirst (1989); Kahn and Goldman (1991); and Goldman and Kito (1995).
[91] For a recent argument for expanding demand-side resource participation in all-source solicitations and adopting all-source solicitations as a tool for increasing investments in demand-side resources, see Henderson (2018).
[92] PSCo (2016a), 1–70.
[93] SCE (2013b); EPE (2017); PSCo (2017a); NIPSCO (2018b); OG&E (2018).

requirements, and considerations for different resources. Different products have individual RFP documents and product-specific model contracts. For instance, wind and solar projects will require different model contracts than natural gas-fired generation. Table 8 illustrates products solicited by utilities in recent all-source procurements.[94]

Table 8. Products Solicited by Utilities in Recent All-Source Procurements[95]

Utility	Solicitation Year	Products
SCE	2013	Gas-fired generation CHP Demand response Energy efficiency Energy storage Renewable Resource adequacy[96] Distributed generation
PSCo	2017	Company ownership[97] Dispatchable resources Renewable resources Semi-dispatchable renewable capacity resources
NIPSCO	2018	Dispatchable Semi-dispatchable Renewables Demand resources Stand-alone and paired storage Contractual arrangements

3.4.5 Confidentiality Issues

Balancing transparency and confidentiality of bidders' and utilities' commercially sensitive information is essential for maintaining the integrity of all-source solicitations. There are two main confidentiality concerns. First, bidders may have concerns over giving utilities or other developers access to information on technology, cost, and bidding strategies. Second, utilities may have concerns giving non-utility suppliers access to information on operations and cost that is used to develop resource plans. Nevertheless, bidders and utilities need access to each other's information. Additionally, PUCs, independent evaluators, and, in some cases, consultants need access to bid information.

In practice, the main strategies for balancing transparency and confidentiality are procurement rules that govern nondisclosure agreements. Nondisclosure agreements stipulate the conditions under which parties can share confidential information and notification requirements for when they do so. Nondisclosure agreements may be "bilateral"—between the utility and individual bidders or between the utility and intervenors—and may be included as part of RFP documents.[98]

[94] PSCo procured demand-side resources through a separate process. PSCo (2016a).
[95] SCE (2013a); PSCo (2017a); NIPSCO (2018b).
[96] *Resource adequacy* refers to resources that only offer capacity used to meet resource adequacy requirements.
[97] *Company ownership* refers to the sale of new or existing assets to PSCo.
[98] For example, NIPSCO's RFP documents contain a bilateral confidentiality agreement. See https://www.nipsco-rfp.com/RFP-Documents.

3.5 Evaluation and Selection

3.5.1 Evaluation Process

All-source evaluation and selection typically includes four stages: (1) initial screening to identify offers meeting basic eligibility requirements (Section 3.4.3); (2) preliminary evaluation to identify a short list of best offers; (3) full evaluation of the short list of offers; and (4) selection of one or more projects for PUC approval, based on the full evaluation.

Preliminary evaluation often uses cost offers and an assessment of qualitative factors to short-list bids, with only offers that have the lowest costs and meet qualitative criteria moving on to full evaluation. In all-source solicitations, bids are grouped by resource type and, in some cases, ownership structure for preliminary evaluation. Full evaluation uses computer-based modeling but often also includes an assessment of qualitative factors. The remainder of this section focuses on the full evaluation process.

3.5.2 Evaluation Criteria

Utilities use a broad range of quantifiable benefits and costs ("price factors") and qualitative characteristics ("non-price factors") to evaluate bids. At a high level, many of these evaluation criteria are common across all-source solicitations, though specific non-price criteria differ (Table 9). Commonly used non-price criteria include development and contract risk, bidder financial viability, technology viability, policy compliance benefits, resource diversity, transmission system impact, resilience, environmental impact, and utility financial impact.[99] In some cases, PUCs provide more proactive guidance on the scope of these evaluation criteria, whereas in other cases they approve criteria by approving RFP documents or through CPCN filings.[100]

How these criteria are applied varies across jurisdictions. Some PUCs require utilities to develop weighting and scoring systems for price and non-price factors. Table 10 shows an example from OG&E's 2018 all-source solicitation. In other cases, utilities incorporate price and non-price factors in their evaluation and present the results of this analysis in their filings for PUC approval of selected resources. There are trade-offs between these approaches. Weighting and scoring can be more transparent than qualitative assessment of non-price factors but may introduce a false sense of accuracy. An assessment must be made of the "correct" weights, and scoring for non-price factors may be subjective. Additionally, transparent weighting and scoring systems may invite gaming by bidders.[101]

[99] For a more detailed background on non-price factors, see Tierney and Shatzki (2008).
[100] New Mexico's proposed procurement requirements provide an example of proactive commission guidance on evaluation criteria (NMAC n.d.). Colorado is an example of a commission that approves evaluation criteria in RFP documents (Colorado PUC 2018). In California, the commission approves evaluation criteria in CPCN filings (SCE 2013).
[101] For an overview, see Kahn et al. (1989).

Table 9. Price and Non-Price Factors Used in Recent All-Source Solicitations[102]

Utility (Year)	Price Factors	Non-Price Factors
SCE (2013)	Based on a least-cost best-fit methodology[103] Benefits: energy, ancillary services, resource adequacy capacity Costs: dispatch, contract or revenue requirements, debt equivalence, transmission, compliance with greenhouse gas (GHG) emission requirements	"Environmental & permitting status; electrical interconnection; fuel interconnection & source; water interconnection & source; project financing status; project development experience; thermal host (CHP only); FERC & California (CA) QF standards (CHP only); emissions performance standards; site control; large equipment status; reasonableness of commercial operation date; transmission area; modifications to *pro forma* documents; GHG contributions towards the CHP Settlement Agreement target; contributions towards SCE's RPS targets; congestion, negative price, and curtailment considerations not captured in the quantitative valuation; portfolio fit of energy, capacity, & term; offeror concentration; technology concentration; dispatchability & curtailability; offer price in excess of public or independent data (i.e., in excess of shadow cost curves); LCR effectiveness factor of interconnection"
EPE (2017)	"Net capacity offer or purchase offer and capacity costs; energy costs, including fuel costs; fixed and variable O&M costs; unit start-up costs; variable costs impacting production cost; transmission and/or distribution system costs; other costs and system impacts; potential federal regulation of carbon emissions costs and taxes"	"Resource siting - letter of Intent for site control; right-of-way acquisition; environmental and other permitting; resource financing; design/procurement/ construction status; firm transmission capacity; commercial operation date and completion security; reliability of technology; ability of the resource to continue operating in extreme hot and cold weather temperatures; project team capabilities; performance guarantees and limitations on remedies; bidder's financial strength; operation and maintenance plan; environmental and regulatory compliance; environmental impact dispatching limitations; cyclic on/off operation capability; automatic generation control; ancillary services (e.g., voltage support and load following); start-up characteristics; maintenance coordination; transmission impact/voltage control; water efficiency; other factors; resource expansion capability; stability of price proposal; economic development benefits; diversity of overall resource portfolio; cash flow; debt ratio; bond ratings; capital attraction"
PSCo (2017)	Based on capacity expansion modeling; includes incremental transmission (interconnection and upgrade) costs, line loss costs, integration costs (non-dispatchable resources), gas supply costs, benefit of geographic diversity of wind generation resource, benefit of energy storage resource, surplus capacity credit, adder for gas price volatility mitigation	"Financial strength of the respondent; financing plan, including ability to utilize tax advantages; development, construction, and operation experience; generator technology, availability, and warranties; environmental permitting and compliance; land use permitting and zoning; other permitting; real property acquisition/site control progress and plan; project operational characteristics; scale of the project; community support for the project; transmission access plan feasibility and arrangements; transmission upgrade schedule assessment; construction and equipment supply plans and arrangements; project execution planning; accreditability of capacity to meet reliability needs; accounting assessment"
OG&E (2018)	Net present value of customer impact; utility financial impact	Contract risk, costs, and benefits; operational characteristics and viability; locational benefits, reliability, resiliency, and security; overall project development risk, including critical path schedule, site control, technology, fuel, bidder experience, resource financing, and community engagement; resource diversity and scalability; environmental impact

[102] SCE (2013a); EPE (2017); PSCo (2017a); PSCo (2016b); OG&E (2018).
[103] According to the least-cost best-fit methodology, bids are evaluated based on their net market value, or their benefits minus their costs.

Table 10. OG&E's Weighting Framework for Evaluating Bids: 2018 All-Source Solicitation[104]

Criteria	Weight (%)
Non-price evaluation criteria	**50**
Contract risks, costs, and benefits	15
Operational characteristics and viability	10
Locational benefits, reliability, resilience, and security	10
Overall project development risks	5
Resource diversity and scalability	5
Environmental impact	5
Quantitative evaluation criteria	**50**
Net present value of OG&E customer impact	40
OG&E financial impact	10

3.5.3 Economic Evaluation Methods

Economic evaluation is one of the main challenges in all-source solicitations because of the diversity of resource bids. In addition to different ownership structures and contract lengths, bids may include resources with very different operating characteristics, different combinations of resources within the same bid, or bids for resources that are shaped or firmed with energy storage or energy market purchases.

Comparing different resources solely in terms of their bid costs will not result in a least-cost resource portfolio, as different resources may provide different value to the utility. For instance, an energy storage resource may be more expensive than a CT on a gross capacity cost ($/kW-yr) basis but may be lower cost on a net capacity cost basis, because it provides higher energy and ancillary services benefits. Accounting for value, rather than focusing on bid cost alone, is thus an essential part of all-source economic evaluation.

Market pricing provides a useful lens for thinking about a resource's value. The value of a resource that a utility offers in ISO/RTO markets is the energy, ancillary services, and capacity market revenues that it earns. The net market value to the utility will be the resource's revenues minus its costs. For instance, a wind resource that has average energy and capacity market revenues of $25/MWh and a PPA price of $20/MWh will have a net market value of $5/MWh. Net value is a broader category than net market value and may include values that are not captured in markets, such as transmission and distribution deferral value. This net value framework also is applicable to utilities that do not participate in ISO/RTO markets, using shadow prices (system lambdas) rather than market prices.

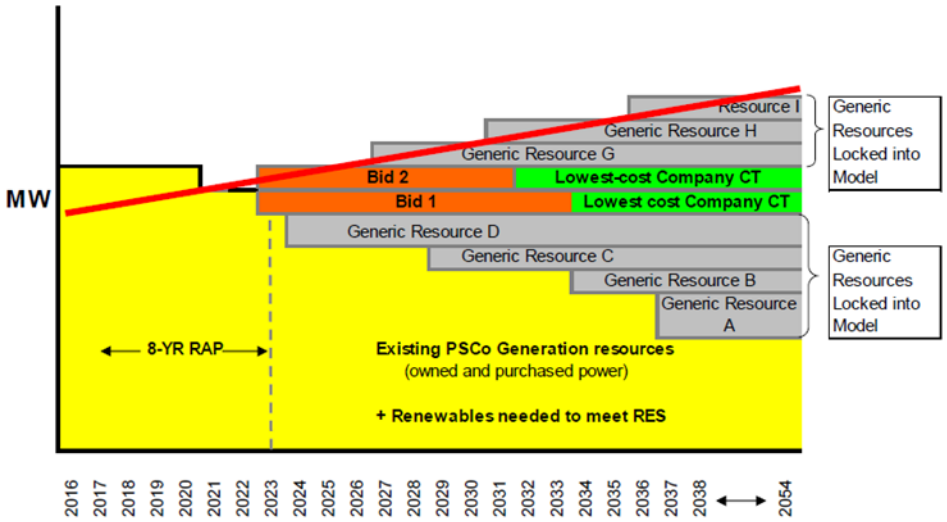
Utilities generally use one of two approaches to evaluate the benefits and costs of bids: (1) portfolio evaluation of bids using capacity expansion models ("portfolio evaluation approach") or (2) net value evaluation for each bid ("resource evaluation approach") using energy, ancillary service, and capacity market price forecasts to calculate market value. In the portfolio evaluation approach, utilities evaluate bids based on their impact on utility portfolio costs. In the resource evaluation approach, utilities evaluate bids based on their individual benefits and costs. The two approaches differ in terms of their choice of models. Portfolio evaluation uses capacity expansion models, whereas resource evaluation uses production simulation models.

PSCo's 2017 solicitation and SCE's 2013 solicitation illustrate these different approaches. PSCo used a capacity expansion model to evaluate optimal (system cost minimizing) portfolios of bids and self-build proposals that fulfill its resource adequacy need (Figure 4). Because PSCo's acquisition period is shorter (2017 to 2023), and the model horizon extends to 2054, the utility used a generic resources plan to fill in

[104] OG&E (2018).

resource needs after the acquisition period.[105] Specifically, because these different types of resources (bids versus self-build proposals) have different contract durations and economic lifetimes, PSCo backfilled each resource with a self-build CT ("lowest-cost Company CT" in Figure 4) after the resource reaches the end of its contract or expected lifetime.

Figure 4. Illustration of PSCo's Modeling Framework for Portfolio Selection[106]

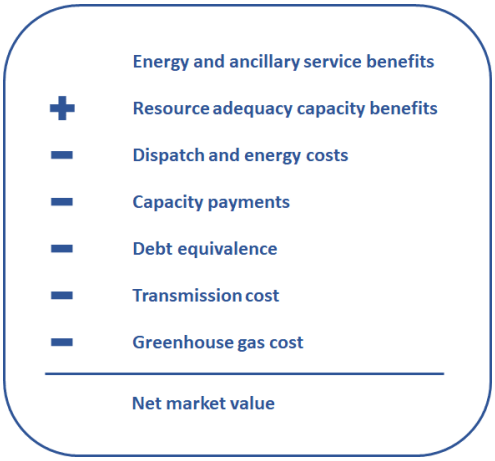


For computational reasons, capacity expansion models have limited operational detail and limited to no representation of the transmission and distribution systems, resulting in a narrower set of potential resource benefits and costs. PSCo incorporated unaccounted for benefits and costs through credits (reductions) and adders (increases) to resource costs.[107] These benefits and costs include incremental transmission costs (for interconnections and upgrades), integration costs and geographic diversity benefits (for non-dispatchable resources), firm natural gas supply costs (if not provided in the bid), avoided line losses and transmission and distribution costs (for DERs), and reduced exposure to natural gas price volatility (for resources other than natural gas-fired units). These inputs were based on company estimates or separate studies and were described in RFP documents.[108]

In its 2013 all-source solicitation, SCE used the California Public Utilities Commission's least-cost best-fit framework for evaluating the present value net costs of bids. This framework calculates a net market value for individual resources by summing benefits, or the resource's market value to the utility, and subtracting operating costs, contract payments, and other utility costs for the resource (Figure 5).

[105] Generic resources include combined-cycle and simple-cycle gas-fired generation, wind generation, and solar generation. These generic resources are selected by the model. See PSCo (2016b).
[106] PSCo (2016b).
[107] As a simplified example, a wind resource that has a $30/MWh levelized cost might have a $2/MWh integration cost adder, a $1/MWh diversity credit, and a $2/MWh reduced fuel price exposure credit. Its net cost used for modeling would be $29/MWh.
[108] PSCo (2016b).

Figure 5. Net Market Value Framework Used in SCE's 2013 All-Source Solicitation[109]



SCE calculated energy and ancillary services benefits by dispatching individual resources against market price forecasts for these services, using price forwards and, for later time periods, a production simulation model. The utility calculated capacity benefits as a capacity credit ("net qualifying capacity") for that resource multiplied by a forecast of resource adequacy costs in California over time. The net market value is the net present value of each resource over its proposed project duration. SCE then ranked bids by their net market value and an assessment of qualitative considerations.

Despite analytical differences, the portfolio evaluation and resource evaluation approaches have a similar economic logic. Both approaches capture benefits and costs of different resource types for comparable evaluation of a diverse range of resources. Both enable comparable evaluation of DERs—as a potential resource in capacity expansion models in the portfolio evaluation approach or through direct evaluation of their benefits (avoided costs) in the resource evaluation approach.[110] Both enable incorporation of values, such as resilience, that are not calculated endogenously in traditional models.

However, differences in assumptions between the two approaches will typically lead to different results, and there are trade-offs associated with each. The portfolio evaluation approach is less transparent, may include less operational and network detail, and may require a greater reliance on adders and credits to account for costs and benefits that are not captured in the model.[111] The resource evaluation approach assumes that new resources will not impact market prices (price-taker assumption) and, relatedly, that interactions among resources with the utility's existing and future portfolio can be captured through adders or qualitative factors. In general, the resource evaluation approach is better suited to utilities that participate in centrally organized markets, where market prices for day-ahead energy, real-time energy, and ancillary services are discoverable and market liquidity makes the price-taker assumption more realistic.

The complexity of modeling in bid evaluation underscores the importance of consistency between modeling inputs and assumptions used in utility resource plans, updated for changes in technology costs

[109] Based on SCE (2013a).
[110] Smaller resources create computational challenges for capacity expansion models. To address this issue, PSCo's 2017 all-source solicitation either (a) aggregated small (<10 MW) bids that were within close (five-mile) proximity, had the same interconnection point, and would total more than 10 MW when aggregated, or (b) compared small bids to the most expensive resource for that generation type selected in the model. See PSCo (2017a).
[111] With regard to transparency, capacity expansion model results are not always intuitive with respect to why the model selected a resource.

and market conditions, and those used to evaluate bids in competitive solicitations. Consistency helps to provide greater transparency to bidders and regulators.

3.5.4 Key Economic Evaluation Issues

The changes in relative technology costs and system economics described in Chapter 2 require improvements in economic evaluation methods that are still ongoing, including enhancements in utility planning models (see text box). This section examines emerging issues in capacity crediting, wind and solar integration costs, energy storage valuation, congestion costs, transmission and distribution deferral, and fuel price risk. Resilience is an emerging area for utility evaluation, but was not quantitatively considered in bid evaluations identified for this report and is not covered in detail here.

Model Enhancements to More Accurately Evaluate Solar and Wind Generation

Utility planning models fall into three general categories: (1) reliability models to evaluate resource adequacy; (2) capacity expansion models to develop least-cost resource portfolios over time; and (3) production simulation models to calculate detailed dispatch and operating costs for a snapshot in time.

All of these models require enhancements to more accurately capture variable and uncertain operating characteristics and geographic diversity of solar and wind generation. For variability, that requires higher temporal resolution. For uncertainty, that requires more probabilistic representation of power system operations. For geographic diversity, that requires a more detailed representation of solar and wind production profiles in different areas, transmission costs to develop these resources, and the overall transmission network.

Adding more temporal and spatial complexity into utility planning models will quickly exceed their practical computational limits, requiring simplification and use of other models and techniques to develop exogenous (outside the model) inputs. For instance, models can address uncertainties in load, solar, and wind—and correlations among them—through statistical sampling to develop load, solar, and wind profiles as modeling inputs. More detailed reliability, production simulation, and transmission studies also can be used to develop inputs for capacity expansion models, which in turn can provide resource portfolios for reliability and production simulation studies. Ongoing computational improvements will increase the scope of what can be endogenously (within the model) included in utility planning models.

Further reading: Sullivan et al. (2014); Cole et al. (2017); Go et al. (2020).

Capacity crediting. How resources are credited for their contributions to resource adequacy has a significant impact on all-source procurements, which often are structured around a resource adequacy need. Dispatch-limited and energy-limited resources can contribute to resource adequacy but do not do so at their nameplate capacity. Accurately accounting for their contributions to resource adequacy requires a de-rate factor, relative to nameplate capacity. Utilities are increasingly using an effective load carrying capability (ELCC) methodology to calculate this de-rate factor for wind generation, solar generation, and to a lesser extent energy storage. ELCC values are calculated through reliability studies. In centrally organized markets, utilities can use the capacity credit values calculated by the ISO or RTO for resource adequacy requirements.[112]

Whether using the ELCC methodology or ISO/RTO capacity credit values, utilities must make assumptions about long-term regional generation mixes because ELCC values for wind, solar, and energy

[112] These values correspond directly to the values that utilities can use to calculate compliance with their resource adequacy obligations. ISOs/RTOs use different methods to calculate capacity credits.

storage decline with increasing penetration.[113] For utilities that do not participate in centrally organized markets, resource plans include long-term generation portfolio forecasts, though these plans require assumptions about the contribution of imports to resource adequacy. Utilities participating in centrally organized markets must project how changes in the regional generation mix will affect ELCC values over time, because ISOs and RTOs only calculate capacity credits for the next resource adequacy period.

Both the methods used to calculate capacity credits and approaches to coordination with respect to long-term regional generation mix are continuing to evolve, creating some procurement uncertainty and risk for utilities. This risk underscores the importance of utilities regularly updating the methods they use to credit the capacity contribution of various types of resources in planning and procurement.

Wind and solar integration costs. Some utilities have historically used integration cost adders in resource planning and procurement to account for the incremental system costs of wind and solar generation that are not captured in models, such as increased cycling costs for thermal units.[114] In all-source solicitations, integration costs are important because they affect the relative cost of energy from different resources. Some utilities use integration cost adders that are developed from detailed production cost studies, while others do not use integration cost adders.[115] In any case, wind and solar integration cost adders are generally small.[116]

Continued growth in wind and solar generation, coal and nuclear unit retirements, changes in the operational capabilities (dispatchability) of wind and solar generation,[117] and more frequent pairing of wind and solar generation with energy storage in bids will all affect integration costs. For utilities that use integration cost adders, it is important that they accurately reflect incremental costs—those not already captured in models.

Energy storage valuation. Broadly, energy storage is not a new resource in utility resource plans. Some utilities have incorporated pumped storage and, to a lesser extent, flywheels and compressed air energy storage into resource planning evaluation for decades. However, a combination of policies, cost reductions, and technological innovations have the potential to significantly increase the amount of storage utilities add to their resource mix. Further, increasing commercial viability has prompted concerns that storage is not being adequately valued in utility resource evaluation.

Existing capacity expansion and production cost models typically include an energy storage dispatch logic. Concerns about valuation have focused on the sub-hourly dispatch benefits of storage,[118] or where storage can be used within the operating day to more cost-effectively address load, wind, and solar forecast uncertainty, generation and transmission outages, and ramping constraints. Existing models often simulate hourly rather than sub-hourly dispatch, though they may still capture some of these sub-hourly effects by simulating an hourly real-time dispatch. Whether the computational costs of incorporating sub-hourly operations into models will be justified, relative to the benefits or alternative methods of incorporating sub-hourly dispatch benefits, is still unclear.[119]

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[113] Wiser et al. (2017); Carden and Wintermantel (2019).
[114] Mills and Wiser (2012); Porter et al. (2013).
[115] For instance, among the solicitations reviewed in this report, APS (2016 solicitation) and PSCo (2013, 2017 solicitations) used integration cost adders for wind and solar generation, while SCE (2013 solicitation); EPE (2017 solicitation); NIPSCO (2018 solicitation); and OG&E (2018 solicitation) do not appear to have done so.
[116] For instance, PSCo's integration cost adders are generally less than $3/MWh and decline over time as the utility's coal units retire (Xcel Energy Services 2016). See also Mills et al. (2013) and Wiser and Bolinger (2018).
[117] Loutan et al. (2017); E3 (2018).
[118] Cooke et al. (2019).
[119] Production simulation models that include a representation of real-time energy markets already incorporate at least some, if not most, of these sub-hourly benefits. Developing sub-hourly dispatch logic requires a significant increase in data and computational requirements. It is unclear if this approach will lead to a commensurate increase in accuracy relative to

Congestion costs. Congestion refers to the inability to dispatch resources in merit order because of transmission constraints. Congestion has important implications for utility procurement because (1) new resources can increase congestion, reducing their value, and (2) utility-scale storage and DERs sited on the high-cost side of a transmission constraint can reduce congestion, increasing their value. Models used in bid evaluation may not capture congestion at all or may capture it to different extents. In some cases, utilities use qualitative methods to evaluate congestion risks. Congestion costs are inherently difficult to forecast because they depend on ISO/RTO transmission expansion plans and the siting and resource decisions of other market participants. Market participants also have limited ability to hedge long-term congestion costs through ISO/RTO financial transmission rights, which are short term. Continued growth in wind and solar generation, and the availability of lower-cost storage, will likely increase the importance of accurately evaluating congestion costs and risks in all-source procurement.

Transmission and distribution deferral. Changes in aggregate loads that result from procurement of DERs may allow utilities to defer transmission and distribution investments over time.[120] These avoided costs can be captured in the valuation of DER bids to enable greater comparability between DERs and other resources. Models may capture some of the benefits of transmission deferral, through locational marginal prices and zonal capacity prices, but generally do not capture the full value of transmission deferral and do not capture the value of distribution deferral.[121] These benefits can instead be included as a reduction in resource costs (bid cost minus benefits). Benefits also may be able to be targeted, with higher value in constrained areas; however, the location-specific nature of constraints may limit the application of benefits. Targeted procurement through solicitations for non-wires alternatives may be a more efficient means of deferring transmission and distribution investments.[122] When targeted benefits are used, it is important to coordinate between resource planning and procurement and non-wires alternatives procurement, to avoid over-procurement. Currently, methods and practices for calculating and applying transmission and distribution deferral benefits are uneven and lack standardization.[123]

Fuel price risk. Greater reliance on natural gas generation has prompted concerns over the risks of fuel price volatility. In all-source solicitations, capturing fuel price risk is important because resources without fuel costs can provide a long-term hedge against fuel price risk, even during times when current fuel prices are low.[124] Utilities bear fuel price risk when they sign power purchase agreements that have fuel price indices or in tolling agreements[125] where they procure fuel. Although some analysis of fuel price risk is included in resource plans, utilities generally are less transparent about whether and how they will consider fuel price risk in evaluating bids in all-source procurement processes.[126]

incorporating sub-hourly benefits through simplified representations of real-time dispatch, adders based on statistical analysis, or other means.

[120] Increased levels of some types of DERs, particularly distributed generation, may necessitate distribution system upgrades. Here, however, the focus is on load reductions stemming from DER procurement by utilities.

[121] After accounting for the avoided transmission congestion value in locational marginal prices and zonal capacity costs, the residual value of transmission deferral will be the reduced costs of transmission investments needed to meet reliability criteria in ISO/RTO or utility transmission planning. These investments are generally tied to load forecasts.

[122] For an example of the location-specific nature of distribution deferral value, see Cohen et al. (2016).

[123] For instance, only some of the utilities reviewed in this study included transmission and distribution deferral benefits in their bid evaluations. Further, there appears to be some degree of misunderstanding across the electric utility industry between marginal and average costs and what costs are actually avoidable.

[124] Bolinger (2013).

[125] In a physical tolling agreement, the buyer pays the power plant owner (seller) a premium for the right to operate the power plant. The buyer often procures the fuel for the plant.

[126] Among the utilities for which a significant number of all-source RFP materials are publicly available, only two had a detailed description of how natural gas price risk would be addressed in bid evaluation.

3.5.5 Evaluation of Utility-Owned and Non-Utility-Owned Projects

All-source procurements can include a variety of ownership structures. Utilities can own new projects through self-build proposals, by acquiring existing resources, by requesting proposals for utility ownership, through partnerships with non-utility entities, or through build-own transfer (BOT) projects. Non-utility-owned projects typically have power purchase agreements, tolling agreements, or other forms of contractual agreement with utilities.

Ensuring comparability between utility-owned and non-utility-owned projects is a key challenge in all forms of competitive procurement. Three of the most important comparability challenges are debt equivalence, development and performance risks, and contract lengths.[127]

Debt equivalence. Debt equivalence describes the debt-like nature of long-term contractual liabilities. Credit rating agencies impute the debt equivalence of these long-term obligations in establishing credit ratings for utilities, which may increase utilities' borrowing costs.[128] Debates around the treatment of debt equivalence in competitive procurement began in the 1990s and continued into the 2000s.[129] Regulators generally took two, in some cases parallel, approaches to dealing with debt equivalence: (1) allowing utilities to include debt equivalence adders or account for the financial impacts of long-term contracts qualitatively in procurement and (2) addressing debt equivalence in rate cases rather than procurement, by adjusting utilities' cost of capital to account for the imputed cost of power purchase agreements.[130]

In the recent all-source solicitations described in Table 1, some utilities included adders in bid valuation to address debt equivalence. Other utilities considered it as a non-price factor or did not consider it at all in bid evaluation.[131] Because debt equivalence and other utility financial impact metrics have the potential to influence procurement decisions, their use in bid evaluation requires care to mitigate their effect on the competitiveness of the solicitation.

Development and performance risks. Eligibility thresholds, development securities and milestones, and performance standards set requirements for bidders that utility self-bid proposals may not explicitly be required to meet. PUCs can help to ensure a level playing field by building similar development and performance incentives, where appropriate, into prudence review. For instance, PUCs can require utilities to meet agreed-upon construction milestones, cost limits, and availability and other performance requirements as a condition for full cost recovery.[132]

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[127] Limits imposed by rules governing affiliate transactions may present an additional comparability challenge. For instance, restrictions on such transactions may limit the ability of DERs owned by affiliates to provide multiple services, even if the DERs are technically capable of providing those services.

[128] Credit agencies take different approaches to calculating, and place different emphasis on, debt equivalence. Standard and Poor's (S&P) and Fitch calculate debt equivalence quantitatively as the net present value of capacity (fixed cost) payments in the contract, discounted at the utility's cost of debt, multiplied by a risk factor that accounts for cost recovery risk (S&P, Fitch), contract cost relative to market (Fitch), and seller default risk (Fitch). Moody's uses a mix of quantitative and qualitative factors to assess the risk of long-term contracts to utilities. See Ghadessi and Zafar 2017.

[129] Independent power producers argued that including the costs of debt equivalence in competitive solicitations would bias outcomes in favor of utilities. Utilities argued that imputed debt was a real cost that should be accounted for in valuation and rates. For overviews, see GF Energy LLC (2005); The Brattle Group (2008); Tierney and Schatzki (2008); and Ghadessi and Zafar (2017).

[130] Tierney and Schatzki (2008).

[131] For instance, SCE included debt equivalence adders in its 2013 all-source solicitation (SCE 2013b), though California utilities are not permitted to use adders when utilities propose self-build resources in solicitations (Ghadessi and Zafar 2017). EPE considered debt equivalence qualitatively in its 2017 all-source solicitation, as part of a broader set of "EPE financial impact" factors (cash flow, debt ratio, bond ratings, capital attraction) in its non-economic evaluation of bids (EPE 2017). In PSCo's 2017 all-source solicitation, the utility only appears to have considered debt equivalence in the context of comparing contract durations (PSCo 2017a).

[132] PUCs approve the utility costs that are allowed to be recovered from customers through rates.

Contract lengths. Utilities generally can depreciate assets over a longer time horizon than independent developers. That may make utility-owned assets appear to be lower cost. However, longer-lived assets can create technology, market, and regulatory risks for utility customers. PUCs can help reduce these risks by providing more explicit guidance to utilities on how these risks will be addressed in prudence review and by evaluating whether utility ownership terms are consistent with competitive terms in developer bids.

3.5.6 Reporting Requirements

Market price information plays an important role in helping bidders develop their projects and bids. All-source competitive solicitations are not auctions, which means that they do not reveal market clearing prices for capacity or energy. In competitive solicitations, utilities do not publicly report information on winning bid prices, for confidentiality reasons.

Nevertheless, information on bids and bid costs reported as part of the solicitation can be helpful for developers. This information can include, for instance, anonymized information on bid price range or median, the number of projects and installed capacity by resource type, and resources selected in the solicitation. Information reported in solicitations can complement detailed investment and operational cost inputs, assumptions, and results reported in integrated resource plans. In cases where utilities participate in ISO/RTO markets, information reported in solicitations can complement market prices for energy, ancillary services, and in some cases capacity.

Colorado provides an example of systematic reporting requirements. The PUC's Resource Planning Rule 3618(b)(I) requires that:

"Within 30 days after bids are received in response to the RFP(s), the utility shall report: (1) the identity of the bidders and the number of bids received, (2) the quantity of MW offered by bidders, (3) a breakdown of the number of bids and MW received by resource type, and (4) a description of the prices of the resources offered."[133]

Table 2 (Section 1.3) provides an illustration of the kinds of bid price information reported in PSCo's 30-day reports for its 2013 and 2017 all-source competitive solicitations.

3.6 Independent Evaluation

Professional independent evaluators, also called independent monitors, have become an essential part of investor-owned utilities' competitive solicitations. Every all-source solicitation described in Table 1 used independent evaluators. This section focuses on professional independent evaluators, as opposed to third-party intervenors, which also play a monitoring role in all-source solicitations.

They may be hired by the utility, with PUC approval, by the commission itself, or jointly hired by the commission and utility.[134] Independent evaluators are typically paid by utilities, with contracts subject to commission approval. The commission may provide high-level or more detailed requirements for independent evaluators in procurement rules or guidelines.

[133] Colorado PUC (2019), 98.

[134] In Colorado, the independent evaluator is jointly proposed by the utility, the Commission, and the Office of Consumer Counsel (Colorado PUC 2019). In New Mexico, the independent monitor is selected by the commission (NMAC n.d.). In California, independent evaluators are proposed by utilities and approved by the Commission (SCE 2013b).

Possible roles and responsibilities for independent evaluators lie along a spectrum of more active involvement, where the independent evaluator plays a proactive role in managing different stages in the solicitation process, to more arms-length involvement, where the independent evaluator plays a more passive monitoring role and responds to materials provided by the utility (see text box).

Possible Roles and Responsibilities for Independent Evaluators

- "Review and comment on completeness of proposed RFP materials and conformance with relevant requirements;
- Review and comment on proposed evaluation methods and assumptions;
- Oversee written and verbal communications between the commission, its staff, potential bidders, and the utility (including its evaluation teams, transmission evaluation teams, and unregulated generation affiliates);
- Monitor and in some cases, moderate utility public workshops;
- Identify and assist in the resolution of potential disputes arising between parties involved in the procurement;
- Provide feedback to the utility and commission on different elements of the procurement process;
- Validate utility self-build (prior to bid submission);
- Review and validation of models and assumptions used in evaluating offers;
- Management of submitted offers, including initial review of submitted offers and "blinding" of offers in conformance with relevant requirements;
- Oversee of the utility's evaluation process;
- Independently evaluate submitted offers;
- Independently assess portfolios of offers according to broader planning goals;
- Oversee negotiations with bidders; and
- Report on procurement process, results, and lessons learned to regulators."

Source: Tierney and Shatzki (2008), A-1.

Fundamentally, roles and responsibilities of independent evaluators are similar across states. Independent evaluators review RFP materials, evaluation methods, bid selection, and in some cases contract negotiations to ensure that the solicitation process is fair and nondiscriminatory, and make a final determination of the fairness and competitiveness of the process in their reports to commissions.

However, the treatment of independent evaluators, their ability to actively influence the solicitation process, and their more detailed tasks vary across jurisdictions.[135] Common differences include the extent to which the independent evaluator is treated as an independent entity or an advisor to the commission, and relatedly the extent to which the independent evaluator will be expected to testify in proceedings, and rules governing how utilities will be expected to respond to deficiencies identified by the independent evaluator during the solicitation process (Table 11).

[135] This report does not delve into detailed differences in tasks among independent evaluators. As a reference, Sedway (SCE 2014, D-6, 3) provides a helpful list of detailed tasks that it performed in its role as independent evaluator: "reviewed and made suggested improvements to the LCR RFO materials prior to their issuance, reviewed SCE's outreach activities, attended SCE's Bidders' Conference on October 16, 2013, reviewed SCE's evaluation methodologies, commented on evaluation methods and processes, participated in the opening of offers (and retained Sedway Consulting's own copy, of each offer for its own evaluation), discussed offer clarification requirements with SCE, participated in the decisions to disqualify offers that failed to comply with the LCR RFO requirements, performed an independent evaluation of all qualified indicative and final offers, compared Sedway Consulting's evaluation results to SCE's results, participated in discussions regarding offer shortlisting, joined in many of SCE's LCR RFO planning and evaluation meetings, participated in executive-level energy procurement Risk Management Committee (epRMC) meetings in which offer disqualification, shortlisting, and selection decisions were made, participated in debriefing calls and/or meetings with bidders whose projects were not shortlisted or selected, monitored email communications with all bidders, participated in clarification calls with shortlisted bidders to ensure that they were properly filling out revised bid spreadsheets for final offer submission, and monitored negotiation calls with shortlisted bidders."

In all-source procurement, an important function of independent evaluators is to ensure that evaluation methods lead to fair treatment among different resource types. Independent evaluators assess utility evaluation methods by reviewing modeling inputs and assumptions and actively testing the rigor and consistency of evaluation models, or in some cases conduct the evaluation themselves. More active testing approaches include parallel evaluation by the independent evaluator and the use of "mock bids," where the independent evaluator and the utility develop and evaluate likely bids before and during bid evaluation to ensure that utilities have not altered the modeling inputs and assumptions after they were reviewed by the independent evaluator.[136]

Independent evaluators play a critical role in providing assurances for a fair and competitive procurement process. Although specific roles and responsibilities for independent evaluators vary across jurisdictions, developing a clear scope of work helps set industry expectations and allows evaluators to be seen as independent custodians of the competitive process.[137]

Table 11. Roles and Responsibilities of Independent Evaluators in Three Illustrative States

State	High-Level Roles and Responsibilities
California	• Ensure a fair and nondiscriminatory solicitation process • Make a determination as to whether the final selection was free and nondiscriminatory, reporting findings to the California PUC • Testify in California PUC proceedings, as required or requested by the utility or the PUC • Make recommendations to the utility for improvements in the solicitation process during the solicitation (utility is not obligated to make these improvements)
Colorado	• "address in its report whether the utility's proposed competitive acquisition procedures and proposed bidding policy, including the assumptions, criteria and models, are sufficient to solicit and evaluate bids in a fair and reasonable manner" • "generally serve as an advisor to the Commission and shall generally not be a party to the proceedings" • "In the event that the IE [independent evaluator] notes a problem or a deficiency in the bid evaluation process, the IE should notify the utility."
New Mexico	• "will act as an advisor to the commission subject to the commission's exclusive supervision and control" • "shall provide the independent monitor's report to the commission with utility bid analysis results and modeling runs supporting the utility's decision to award a contract responsive to the requests for proposal, including whether the process reasonably invited and considered all feasible resource options and an independent analysis of the winning bid" • "in the event an independent monitor finds a problem or deficiency at any stage in the utility's procurement process, they shall promptly notify the utility and, after the utility responds to that notice, it will promptly notify the commission in writing of the utility's response to and resolution of that problem or deficiency."

[136] For an example of parallel evaluation, see Appendix D (Independent Evaluator Report) in SCE (2014). For an example of mock bids, see Accion Group (2013).
[137] Tierney and Shatzki (2008).

4.0 All-Source Competitive Solicitations for Non-Wires Alternatives in Distribution System Planning[138]

Electric utility distribution systems are composed of medium voltage (typically up to 35 kV) lines, substations, feeders, and related equipment that transport electricity to and from customers and connect to the transmission system.[139] Through the distribution system planning process, utilities determine distribution system investments needed to meet reliability and safety criteria based on load forecasts.

In some cases, procurement of DERs may reduce the costs of meeting certain types of distribution system needs by reducing or shifting the timing of demand and, by doing so, deferring or avoiding capital expenditures. DERs also may provide voltage support and other distribution services in a cost-effective manner.[140] These non-wires alternatives, also called non-wires solutions, are a form of regulated competition for distribution investments. Non-wires alternatives may be at the customer's site (behind the meter) or on the utility side of the customer's meter.

Because utilities often do not have any incentive to reduce distribution capital expenditures, a growing number of states are requiring utilities to consider procurement of DERs to meet certain types of distribution needs, where cost-effective and technically feasible.[141] PUCs also have tested financial incentives for utilities, including a percentage adder on customer- or third-party-owned DER projects that cost-effectively defers distribution system investments (e.g., in California) and shared savings mechanisms (e.g., in New York).

Solicitations for non-wires alternatives are typically a form of all-source procurement. A wide range of solutions—energy efficiency, demand response, distributed generation, and distributed energy storage—may be eligible to participate. To fulfill a distribution system need, resources must be located at specified locations on the distribution system.

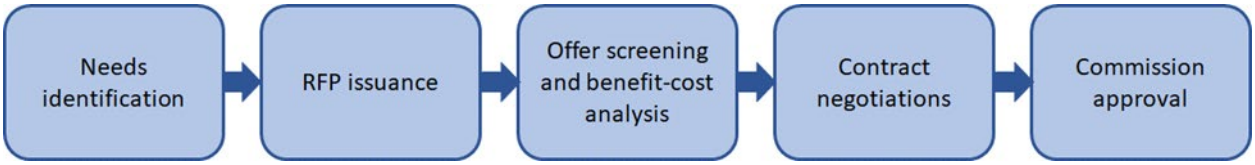
This chapter provides an overview of all-source competitive solicitations for non-wires alternatives, focusing on the procurement process, planning and needs identification, the solicitation process, resource evaluation and selection, and outcomes from recent solicitations.

4.1 Procurement Process

Generally, the process for all-source procurement of non-wires alternatives has five steps (Figure 6). The first step involves needs identification (next section), followed by RFP issuance for offers to fill that need. Utilities screen bids to ensure they meet minimum organizational and technical requirements, undertake benefit-cost analysis (sometimes including development of potential portfolios), and then, for feasible and cost-effective non-wires solutions, enter into contracts with individual resources or an aggregator of resources.

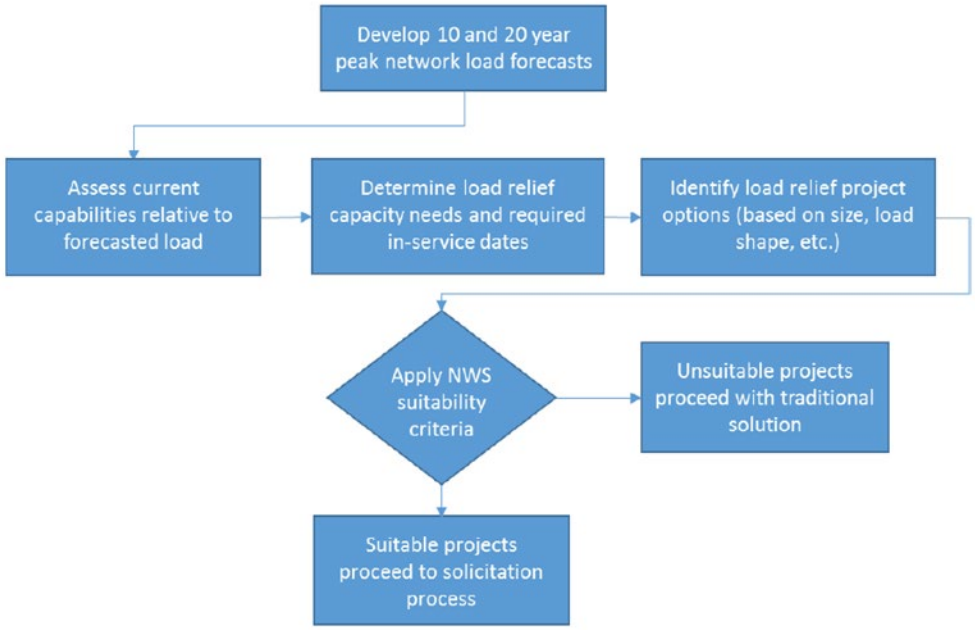
[138] Some transmission service providers also have conducted non-wires alternatives procurements to defer or avoid transmission investments. This chapter focuses on distribution system investments.
[139] Sallam and Malik 2019. The distribution system includes all the components of the cyber-physical distribution grid including the information, telecommunication, and operational technologies and transformers, wires, switches, and other apparatus.
[140] Advanced inverters can provide voltage support through reactive power compensation. "Other reliability services" here refers primarily to "back-tie" services, in situations where utilities need to use feeder switching to reconnect customers after a contingency event. DERs can provide back-tie services by reducing loads on feeders and providing utilities with operational flexibility, based on a preset schedule, in response to a control signal from the grid operator (automatic response), or by directly monitoring grid conditions (autonomous response).
[141] Including California, Colorado, District of Columbia, Hawaii, Maine, Maryland, Minnesota, Nevada, New York, and Rhode Island. See Schwartz (2020).

Figure 6. Main Stages in Non-Wires Alternatives Procurement



The cycle for non-wires alternatives procurement depends on regulatory requirements and distribution planning needs. In New York, distribution utilities identify needs and evaluate solutions as part of their annual capital planning processes. Figure 7 is Consolidated Edison's illustration of this process.

Figure 7. Consolidated Edison's Capital Planning Process for Non-Wires Solutions



Notes: Suitability criteria are discussed in the next section. NWS - non-wires solutions.

In California, distribution utilities are required to publish annually by August 15 a grid needs assessment report that identifies grid needs over the next five years and a distribution deferral opportunities report that identifies locations where non-wires alternatives may be a feasible and cost-effective solution to grid needs. By November 15, utilities are required to submit a distribution investment deferral opportunities list to the California Public Utilities Commission requesting approval for competitive solicitations for non-wires solutions.[142]

In Hawaii, Hawaiian Electric Company's (HECO's) non-wires alternatives procurement is integrated into a single, 18-month integrated grid planning process that jointly considers resource, transmission, and distribution needs.[143] The process includes identifying distribution needs that may be deferred or avoided

[142] California PUC (2019).
[143] See Hawaiian Electric. What is Integrated Grid Planning? https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning.

through procurement of non-wires alternatives. HECO subsequently issues RFPs soliciting offers from non-wires alternatives to meet those needs.

4.2 Planning and Needs Identification

Distribution system planning has historically been relatively opaque with no formal regulatory process for identifying utility investment needs. Over the last decade, PUCs in some states have begun to require utilities to standardize the distribution planning process, make it more transparent, engage stakeholders, integrate consideration of non-wires alternatives, and support emerging markets for distribution services.[144]

The "need" identified in non-wires alternatives procurement is most often a load reduction quantity (MW), sometimes referred to as "load relief," during specific hours of the day ("overload periods") that will enable utilities to defer or avoid one or more specific capital investment projects.[145] The identified need also includes the time (year and season or month) that the non-wires alternative would need to be operational. Table 12 provides examples of identified needs for RFPs for non-wires alternatives.

Table 12. Projects, Needs, and Default Solutions: Example Consolidated Edison Non-Wires Alternatives RFPs[146]

Project (RFP year)	Need	Default Solution
Hudson Network (2017)	Amount: 7.1 MW Location: West 50th St. Substation Overload period: 1–8 pm (5 pm peak) When: 2021 (summer)	Feeder upgrades to reduce potential overloads
Columbus Circle Network (2017)	Amount: 4 MW Location: West 42nd St. No. 2 Substation Overload period: 2–7 pm (6 pm peak) When: 2021 (summer)	Feeder upgrades to reduce potential overloads
West 42nd Street Load Transfer Project (2017)	Amount: 42 MW (total, varies by year) Location: W. 42nd St. No. 1 Substation Overload period: 9 am–7 pm (2–3 pm peak) When: 2021–2027 (starting May 2021)	Transfer 55 MW of load from W. 42nd St. No. 1 Substation to Astor Substation before summer 2021

Not all distribution capital investments can be deferred or avoided through non-wires alternatives. To provide greater transparency into utility consideration of non-wires alternatives and a more systematic process, PUCs have: (1) required utilities to pre-determine criteria for the kinds of capital investments that will include consideration of non-wires alternatives and/or (2) required utilities to regularly assess deferral opportunities, subject to PUC review and oversight. New York's "suitability criteria" are an example of the first approach. They define threshold metrics for project type, timeline, and cost suitability (Figure 8).[147] California's distribution deferral opportunities report, subject to oversight by the PUC and an independent distribution planning advisory group, illustrates the second approach.[148]

[144] Cooke et al. (2018).
[145] Load reduction will be the need identified in solicitations for distribution capacity and back-tie services, though the operational requirements for back-tie services will be different.
[146] Con Edison (2017a, 2017b, 2017c).
[147] Joint Utilities (2017).
[148] For sample distribution deferral opportunities reports, see PG&E (2019) and SCE (2019).

Figure 8. Con Edison's Suitability Criteria for Non-Wires Alternatives Procurement[149]

Criteria	Potential Elements Addressed	
Project Type Suitability	• Project types include Load Relief or Load Relief in combination with Reliability. Other categories have minimal suitability and will be periodically reviewed for potential modifications due to State policy or technological changes.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450k

Because non-wires alternatives needs are tied to specific distribution investment projects, systematic procurement of non-wires alternatives entails incorporating non-wires procurement into the distribution planning process as a regular step, as illustrated previously for Con Edison (Figure 7).

As a regular process, non-wires alternatives procurement requires harmonization with utility bulk system planning and procurement, programs, and rate designs. DERs procured through non-wires alternatives procurement may affect aggregate demand. If sufficiently large, this change in demand should be incorporated into the load forecast that is used in bulk power system planning and procurement. In bulk power procurement and demand-side programs, utilities may acquire DERs that modify customer net loads—load minus self-generation. If feasible and practical to disaggregate load modifications to the distribution level, these changes in net load should be incorporated in the distribution load forecasts used in determining distribution system needs and opportunities for non-wires alternatives.

Targeted demand-side programs and rate design can complement non-wires alternatives procurement. For targeted programs, utilities identify high value areas of the distribution system using marginal cost of service studies and use marginal distribution avoided costs to "geotarget" programmatic expenditures. Utilities also may include marginal distribution costs as a component in retail rates.[150] Changes in customers' net loads that result from targeted programs and rate designs should be incorporated into distribution load forecasts and distribution needs assessments. If targeted programs and rate designs are not sufficient to defer investments, utilities can then conduct solicitations for non-wires alternatives, if suitable.

These interactions highlight the importance of coordination between procurement of non-wires alternatives and other utility processes. Greater consistency among different processes will help to improve efficiency and reduce costs.[151]

[149] The figure is from Joint Utilities (2017).
[150] New York's proposed "full-value tariff" is an example of one such rate. See E3 (2016).
[151] See U.S. Department of Energy's Modern Distribution Grid Project guides.

4.3 Evaluation and Selection

Evaluation of non-wires alternatives typically consists of a screening phase—to determine whether projects meet minimum technical, timeliness, and feasibility criteria—and an evaluation phase.

Bidders generally are not required to submit offers that meet the full need—either the amount (MW) or duration (hours)—identified in the RFP. That raises a threshold question for the utility: Is the total amount and duration of peak load reduction provided by projects that pass the initial screen enough to meet the RFP need? If not, utilities may decide to proceed with a traditional solution without going through the formal evaluation process for non-wires alternatives proposals.[152] In some cases, utilities are proceeding with non-wires alternatives that meet near-term distribution needs, both to further test these alternatives and in the event the forecasted additional load does not materialize.[153]

Utilities in California, New York, and Rhode Island have used benefit-cost analysis frameworks for evaluating non-wires alternatives bids. These frameworks are rooted in the cost-effectiveness tests that have been used for decades for utility demand-side management programs, based on avoided costs. In addition to deferring or avoiding distribution investments, non-wires alternatives may provide additional value to utilities and society, from avoided energy costs to lower air emissions, dependent on the project's location and load reduction profile.[154]

This benefit-cost framework allows utilities to integrate a range of location-specific and time-specific benefits and costs into a single benefit-cost ratio, applied to individual projects or a portfolio of projects. Utilities may add program administration costs, incentive costs, and any incremental distribution network costs to bid costs in their analysis. The focus of this analysis is on net benefits rather than cost. If the benefit-cost ratio for a portfolio of projects, or for all individual projects in that portfolio, is greater than 1.0, the non-wires solution will be cost-effective relative to the traditional solution, even if the total cost of the non-wires projects exceeds the cost of the traditional solution.[155]

In 2016, the New York Public Service Commission directed utilities to develop benefit-cost analysis handbooks to provide transparency on methods used to calculate benefits and costs in non-wires alternatives evaluations and utility programs.[156] Table 13 shows benefit categories for Con Edison's *Benefit-Cost Analysis Handbook*, illustrating the overlapping nature and potential complexity of calculations and the importance of transparency. For instance, locational marginal prices will include some, but not all, components of avoided transmission costs. Among the benefit categories in the table, generally the largest are avoided distribution capacity costs, avoided locational marginal energy costs, avoided zonal generation capacity costs, and, if not already captured in locational marginal prices, avoided cost of emissions.[157]

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[152] For example, in February 2020 HECO cancelled its Integrated Grid Planning Soft Launch RFP, for capital deferral for a new housing/commercial development and emergency overloads at a substation, due to insufficient response to MW and duration requirements (https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning). In the future, the utility plans to pursue programmatic approaches for non-wires alternatives to help meet distribution needs for future developments and defer or avoid substation transformers. Con Edison cancelled its Hudson RFP in 2017 (Con Edison 2018a).

[153] Chew et al. (2018); NV Energy (2019b).

[154] NREL maintains a database on distribution infrastructure upgrade costs—the costs DERs may be able to defer or avoid in the context of non-wires alternatives: https://data.nrel.gov/submissions/101.

[155] For instance, the cost (all costs in present value annualized terms) of a traditional solution might be $100/kW-yr and the total cost (bid cost plus incremental network cost) of the non-wires solution might be $120/kW-yr. If the non-wires solution has energy, ancillary services, and capacity benefits of $40/kW-yr, its net costs would be $80/kW-yr. Equivalently, the non-wires solution would have a benefit-cost ratio of 1.2 ($140/kW-yr/$120/kW-yr).

[156] For another example benefit-cost methodology that captures time-specific and location-specific benefits and costs, see California's locational net benefit analysis, https://drpwg.org/sample-page/drp/.

[157] For an energy efficiency-specific example in New York, see White et al. (2018).

Table 13. Benefit Categories, Descriptions, and Data Sources: Con Edison's Benefit-Cost Analysis Handbook[158]

Benefit Categories	Description	Data Source
Avoided generation capacity cost (AGCC)	Reduced zonal installed capacity market costs via reductions in coincident peak demand	Long-term forecast (ICAP spreadsheet model) for installed capacity prices, maintained by Department of Public Service (DPS) staff
Avoided locational based marginal prices (LBMPs)	Reduced energy market costs based on day-ahead zonal LBMPs, which also include transmission congestion and loss components	NYISO long-term forecast in its *Congestion Assessment and Resource Integration Study (CARIS)*
Avoided transmission capacity infrastructure and operation and maintenance (O&M)	Reduced baseline transmission investment costs; only included when a project or portfolio reduces transmission costs that are not already captured in AGCC and LMBPs	Project-specific engineering study
Avoided transmission losses	Reduced losses when a project changes the topology of the transmission system; incremental to marginal transmission losses included in the LBMP	Project-specific engineering study
Avoided ancillary services	Markets benefits of DERs that will provide ancillary services in the NYISO market; does not include reduced ancillary services market costs from load reductions[159]	Historical data using the NYISO *Operations & Markets* reports
Wholesale market price impact	Benefit of reduced installed capacity market prices and LBMPs; included in the Ratepayer Impact Test and Utility Cost Test as a sensitivity	Calculated by DPS staff
Avoided distribution capacity infrastructure	Deferrable or avoidable cost of distribution capacity investments from load reductions	Marginal cost of service study or project-specific costs
Avoided distribution O&M	Avoided distribution O&M costs from load reductions; expected to be zero for most resources	Pending further study
Avoided distribution losses	Reduced costs from percentage reductions in distribution losses; reductions in losses from reduced energy use are already captured in the AGCC and LBMP calculations	Project-specific engineering study
Net avoided restoration costs	Avoided cost of restoring power during outages; for most resources, already included in avoided distribution capacity costs	Project-specific engineering study
Net avoided outage costs	Reduced customer outage costs; currently limited application	Pending further study
Net avoided CO_2	Avoided cost of CO_2 emissions not already included in the LBMP	Net marginal damage cost of carbon provided by DPS staff
Net avoided SO_2 and NO_X	Value of incremental reductions in SO_2 and NO_X emissions from sources not covered in cap-and-trade programs	Forecasted allowance prices are from NYISO *CARIS*
Avoided water impact	Value of reduced water use; assessed qualitatively	Not assessed quantitatively
Avoided land impact	Value of reduced land impact; assessed qualitatively	Not assessed quantitatively

[158] Con Edison (2018b).

[159] The utilities state that "There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels" (Con Edison 2018b, 25). However, NYISO frequency regulation requirements appear to be based on load forecasts (NYISO 2019) and are allocated to load serving entities based on hourly or daily loads (NYISO 2020). That implies that avoided regulation costs should be considered at least in two of the cost-effectiveness tests: the Ratepayer Impact Test and Utility Cost Test. Given the small size of the frequency regulation market, however, the ancillary service market benefits of load reductions are likely to be small.

Methods for evaluating non-wires projects continue to evolve. For instance, the benefits in Table 13 do not capture the real-time flexibility benefits of distributed storage or demand response, because reduced energy costs are calculated using locational day-ahead market prices. Utilities also are beginning to explore methods for incorporating resilience benefits into their evaluation frameworks. For instance, the New York utilities' benefit-cost analysis handbooks contain two "reliability/resiliency" categories: net avoided restoration costs, which captures the benefits of measures that reduce the costs of restoring power after an outage, and net avoided outage costs, which captures the benefits of measures that reduce the frequency and duration of outages for non-participating customers. The application of these categories is still at an early stage.[160]

Location is an important trade-off for utilities in non-wires alternatives procurement. Non-wires projects are located at different locations relative to a substation, feeder, or other location of need. Projects that are more strategically located to meet the need will provide more effective solutions, but limiting the geographic scope of the RFP to a narrow set of locations may not result in sufficient competitive bids. Alternatively, higher concentration in a limited geographic area of some kinds of non-wires alternative projects, in particular distributed generation and storage, may be more likely to trigger the need for other distribution system investments to maximize their system value.[161]

The locational evaluation of these trade-offs compares: (1) effectiveness of the non-wires alternative in meeting the identified distribution system need, based on the amount of the distribution deferral value that a project will capture, and (2) total project cost, including any incremental distribution system costs to accommodate the project(s). More temporal granularity in bulk power system benefits—for instance, hourly avoided energy and capacity benefits—can help to facilitate more accurate assessment of trade-offs as well, because different types of DERs have different load reduction profiles.

Use of traditional benefit-cost analysis requires a choice of cost test to determine which benefits and costs will be included. As has historically been the case with utility programs, jurisdictions may prefer certain cost tests in non-wires alternatives procurement. For instance, the PSC requires regulated New York utilities to use a societal cost test as the primary measure of cost-effectiveness, but allows them to also consider the Utility Cost Test and Ratepayer Impact cost test.[162] Rhode Island utilities have used a Total Resource Cost test or a state-specific test.[163]

Utilities can evaluate non-wires alternatives bids on an individual basis or as part of a portfolio of bids. The portfolio approach generally is more accurate, as projects within a portfolio may be interactive. Integrated portfolio analysis of DERs, for non-wires alternatives procurement and utility procurement more broadly, is still relatively nascent.[164]

As in all-source procurements for bulk power system needs, utilities assess non-wires alternatives bids based on a combination of quantifiable benefits and costs and qualitative considerations. Qualitative considerations may include project viability and execution risk, developer qualifications, site control, timeliness, operational risk, safety, and community impact.[165]

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[160] In many jurisdictions, there are still physical limitations on the ability of DERs to reduce power restoration costs or outage costs, such as restrictions on islanding.
[161] For example, higher concentrations of distributed generation and storage may require infrastructure upgrades to maximize their system value or may require software upgrades to help better manage these resources. For a discussion of trade-offs in locating non-wires alternatives, see Tierney (2016).
[162] Con Edison (2018b).
[163] This state-specific test is the Rhode Island (RI) test. See National Grid (2019).
[164] Mims Frick et al. (2018).
[165] For examples, see Con Edison (2017a, 2017b, and 2017c); and PG&E (2019).

4.4 Lessons and Emerging Issues

A growing number of utilities have held all-source solicitations for non-wires alternatives. More systematic utility procurement of these resources is relatively recent, and only a small number of non-wires alternatives projects that were procured through formal solicitations are in active operation.[166]

Nevertheless, utility procurements to date have provided valuable experience and insights. Key lessons include the following:[167]

- Regulators will likely need to set clear rules for utility ownership and can consider other types of financial incentives.
- More frequently collected, more granular, and higher quality distribution system data and forecasts are critical inputs into the planning tools used to evaluate the need, suitability, and cost-effectiveness of non-wires alternatives.
- More work is needed to develop end-use load profiles and time-sensitive values of various DERs[168] and to assess performance of DERs in non-wires alternatives applications.[169]
- Developer and customer education and outreach are an important foundation for non-wires alternatives procurement.
- Pre-qualification of bidders can help to streamline the solicitation process and allow it to scale over time.
- Transparency in the RFP process, evaluation methods, and interconnection requirements are critical for successful solicitations.
- New methods and tools may be needed for more effective consideration of the suitability and cost-effectiveness of non-wires alternatives, to capture values that often have been omitted from utility evaluations, and to avoid potential double counting of values.
- Developers may need longer lead time for some kinds of non-wires alternatives projects, which may imply developing longer or multi-phase distribution system planning horizons.
- Some locations with identified distribution system needs may not be well-suited to the kinds of non-wires solutions that developers can deploy. Utilities may need to conduct additional outreach or use RFIs to test the market.
- Contracts for non-wires alternatives projects require standardization and clarity on performance risks and incentives.
- Progress is needed to support DER aggregation and facilitate the participation of DER aggregators in non-wires alternative solicitations.

[166] Chew et al. (2018); EPRI (2019).
[167] Chew et al. (2018); Con Edison (2018a); HECO (2019); Hile et al. (2017); EPRI (2019).
[168] Mims Frick et al. (2019); Mims and Schwartz (2019); SEE Action Network (2020a).
[169] SEE Action Network (2020b).

- Operation of distribution-level resources, and particularly customer-owned resources, needs to be integrated into utility operating practices and procedures.

- Energy storage presents unique opportunities but also unique challenges for non-wires alternatives projects, because permitting, interconnection, and operating requirements may not be clear.

Non-wires alternatives procurement has been limited, in part, by low growth in electricity demand. Expected increases in distribution system loads from building and transportation electrification have the potential to increase the deployment of non-wires alternatives over the next decade.

Growth in non-wires alternatives would require changes in the ways utilities operate their distribution systems and interact with bulk power system markets, in order to maximize the distribution-level and bulk power system value of these resources.[170] Efforts to do so involve an area of overlapping state and federal jurisdiction that has yet to be resolved.[171]

[170] Kahrl et al. (2019).
[171] See, for example, Electricity Advisory Committee (2019).

5.0 Conclusions

Over the past decade, a growing number of utilities have used all-source competitive solicitations to acquire new resources. The results illustrate their potential to discover competitive prices for a range of resources and technologies; develop low-cost, lower-risk, higher-value portfolios with diverse types of resources; and enable greater coordination between procurement of utility-scale facilities and DERs.

All-source competitive solicitations are complex. They require sophisticated evaluation methods and models. Solicitations may include utility self-build projects or allow bidding by utility affiliates. The design and implementation of all-source solicitations involve trade-offs in transparency, stakeholder participation, and time. State utility regulators and independent evaluators play essential roles in building confidence in the fairness of the solicitation process, which is crucial for attracting bidder participation and ensuring competitive results. Yet, in spite of this complexity, all-source competitive solicitations have a simple objective: to find the portfolio of resources, from among all resource options, that will meet system needs and state policy goals at low cost with an acceptable level of risk.

By definition, all-source solicitations for bulk power system needs are resource- and technology-agnostic, with broadly defined needs that are typically oriented around firm capacity. All-source solicitations can complement state energy policies, either by integrating procurement mandates into the solicitation as minimum requirements or by procuring any residual resources needed for policy or regulatory compliance using dedicated solicitations. For instance, a state RPS or energy storage mandate could be addressed: (1) in an all-source solicitation as a minimum requirement, or (2) in a separate procurement for any renewable or storage resources needed for compliance that are not procured through an all-source procurement that enabled offers from these resources.

Utility resource plans provide a foundation for all-source solicitations, and the two are closely related and interactive. These plans identify resource needs, based on load forecasts, generator retirement assessments, power purchase agreement expirations, and policy compliance needs. Resource plans also can supply the modeling inputs and assumptions used in bid evaluations, updated for current market conditions. Conversely, bids from all-source solicitations can inform cost and other inputs used in resource plans.

Evaluation is the central challenge for all-source solicitations. Resources bid into all-source solicitations—from dispatchable thermal resources to customer-sited solar plus storage—have diverse operating characteristics. Evaluation methods for all-source procurements must be able to compare these resources on an equivalent basis. The appropriate metric for economic comparison is net value, which captures a resource's market value and other benefits minus its costs. Both of the main approaches to modeling in bid evaluations, capacity expansion modeling and net market value evaluation, are based on net value assessment.

All-source solicitations can incorporate bids from an array of DER types, from end-use energy efficiency projects to behind-the-meter solar-plus-storage, providing an avenue for discovering market pricing and optimizing utility resource portfolios. DER participation in recent all-source solicitations has generally been low. That raises questions about obstacles to DER participation, what kinds of DERs might be better suited to participating in all-source competitive solicitations, and how demand-side programs and all-source competitive solicitations can better complement one another. With recent advances in DER technology, resource evaluation, and contracting, it is worth exploring whether participation of DERs in all-source solicitations can be improved.

The emergence of cost-competitive battery storage, reductions in the cost of renewable energy resources, and sustained low natural gas prices have led to several emerging issues for utilities for bid evaluation, including assessment of capacity crediting for wind and solar generation and energy storage, integration costs for wind and solar generation, real-time flexibility of energy storage, congestion costs, storage benefits, transmission and distribution deferral, and natural gas price risk. All of these areas require ongoing improvements in evaluation methods.

Although quantitative evaluation is the cornerstone of all-source solicitations, bid evaluation and selection require a significant amount of judgment by utilities and utility regulators. Utilities use an extensive list of qualitative (non-price) considerations to evaluate bids, ranging from developer creditworthiness to project development risk. Non-price considerations are critical for managing risk and selecting viable projects, but they also increase utility discretion and need for regulatory oversight.

A utility's direct participation in a solicitation process through self-build proposals raises regulatory challenges for PUCs. PUCs can help to mitigate opportunities for uncompetitive behavior through clear rules, guidelines, and requirements to use independent evaluators, but this does not obviate the need for regulatory judgment. For instance, PUCs still need to evaluate whether a utility's self-build proposal is comparable to competitive offers, in terms of short-term and long-term risks to ratepayers.

Independent evaluators play an indispensable role throughout the solicitation process, ensuring that the solicitation and selection process are objective and impartial. Independent evaluators typically have a broad range of responsibilities. These may include confirming that RFP materials meet PUC standards for transparency and completeness, facilitating communications between bidders and utilities, assessing utility evaluation methods and models or conducting the evaluation themselves, monitoring and providing feedback on the solicitation process, overseeing contractual negotiations, and resolving disputes between bidders and utilities. Every all-source competitive solicitation reviewed in this report used an independent evaluator.

At the distribution system level, several states and utilities have made progress in establishing viable all-source solicitation processes for non-wires alternatives. Systematic procurement of non-wires alternatives is nascent. A number of areas require continued learning and adjustment, including utility data collection, transparency around utility needs identification, design and implementation of solicitations, contracting, and utility incentives.

Several emerging issues associated with non-wires alternatives have yet to be resolved, such as jurisdictional issues around the dual participation of DERs as non-wires alternatives for utility distribution systems and as resources bid into centrally organized wholesale electricity markets, and how distribution-level dispatch should be integrated with these markets. Resolving these issues will be an important area of focus over the next decade. The value proposition of non-wires alternatives solicitations is likely to increase with growth in distribution system demands from building and transportation electrification.

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STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's 2023 Integrated Resource Plan Update, Application for Certification of Plant Yates Units 8-10	)	Docket No. 55378

CERTFICATE OF SERVICE

I do hereby certify that I have served the following parties with the foregoing **DIRECT TESTIMONY AND EXHIBITS OF ALBERT LIN ON BEHALF SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY,** via electronic mail to all parties in this docket.

This 21st day of June, 2024.

/s/ Curt Thompson

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