

Direct Testimony of Ronald J. Binz
Southern Alliance for Clean Energy & Southface Energy Institute, Inc.
Georgia PSC, Docket No. 44160

STATE OF GEORGIA
BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re:

**Georgia Power Company's
2022 Integrated Resource Plan**

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DOCKET NO. 44160

**DIRECT TESTIMONY OF RONALD J. BINZ
ON BEHALF OF
SOUTHERN ALLIANCE FOR CLEAN ENERGY AND
SOUTHFACE ENERGY INSTITUTE, INC.**

May 6, 2022

I. INTRODUCTION

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

A: My name is Ronald J. Binz. I am a Principal with Public Policy Consulting, a firm specializing in energy policy and regulatory matters. I provide consulting services to a variety of public sector and private sector clients in the energy industries, primarily in the regulatory arena. My business address is 333 Eudora Street, Denver, Colorado, 80220.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am testifying on behalf of Southern Alliance for Clean Energy (“SACE”) and Southface Energy Institute, Inc. (“Southface”).

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A: I have been involved in energy regulation since 1979. From 1995 to 2006, and from 2011 to the present, I have served as principal of Public Policy Consulting, where I provide consulting services on regulation in the energy and telecommunications markets. My focus in recent years has been on performance-based regulation and energy regulatory policy, including Integrated Resource Planning, clean technology, smart grid, and climate issues.

From 2007 to 2011, I was Chairman of the Colorado Public Utilities Commission (“PUC”). In that capacity, I helped implement Colorado’s vision for a “New Energy Economy” and its 30% Renewable Energy Portfolio Standard, participated in the Governor’s Climate Action Plan, rewrote the Commission’s Integrated Resource

1 Planning rules, streamlined telecommunications regulation, promoted broadband
2 telecommunications investment, and improved the Commission's operations.

3 As Commission Chair, I presided over implementation of the Colorado Clean Air-Clean
4 Jobs Act, examining proposals of electric utilities to reduce pollutants from their fleets of
5 coal fired power plants.

6 I also presided over the modification and approval of an electric utility resource plan
7 involving the addition of substantial amounts of new wind capacity, the early closure of
8 two coal power plants to reduce carbon and other emissions and substantial amounts of
9 new energy efficiency savings.

10 From July 2011 to July 2013, I was Senior Policy Advisor at the Center for the New
11 Energy Economy ("CNEE") at Colorado State University. CNEE provides policymakers,
12 governors, regulators, and other decision-makers to develop a roadmap to accelerate the
13 nationwide development of a new energy economy.

14 From 1977 to date, I have participated in more than 150 regulatory proceedings before
15 the Federal Energy Regulatory Commission ("FERC"), the Federal Communications
16 Commission ("FCC"), State and Federal District Courts, the 8th Circuit, 10th Circuit and
17 D.C. Circuit Courts of Appeal, the U.S. Supreme Court, and state regulatory commissions
18 in California, Colorado, Georgia, Hawai'i, Idaho, Maine, Massachusetts, Missouri,
19 Montana, New York, North Dakota, Rhode Island, South Dakota, Texas, Utah,
20 Washington, Wyoming, and the District of Columbia. I have filed testimony in at least
21 sixty proceedings before these bodies, addressing technical and policy issues in
22 electricity, natural gas, telecommunications, and water regulation. I have also testified
23 before U.S. House and Senate Committees sixteen times.

1 From 1996-2003, I served as President and Policy Director of the Competition Policy
2 Institute, an independent non-profit organization based in Washington, DC, advocating
3 for state and federal policies to bring competition to energy and telecommunications
4 markets for consumers' benefit.

5 From 1984 to 1995, I was director of the Colorado Office of Consumer Counsel,
6 Colorado's state-funded utility consumer advocate office. During my tenure, the office
7 was a party to more than two hundred legal cases before the Colorado PUC, FERC, FCC,
8 and the courts. I negotiated rate settlement agreements with utilities, regularly testified
9 before the Colorado general assembly, and presented to professional business and
10 consumer organizations on utility rate matters.

11 My educational background includes an M.A. degree in Mathematics from the University
12 of Colorado (1977), course requirements met for Ph.D., graduate coursework toward an
13 M.A. in Economics from the University of Colorado (1981-1984), and a B.A. with
14 Honors in Philosophy from St. Louis University (1971).

15 I have authored or co-authored numerous publications on energy and regulatory matters,
16 including *Risk-aware Planning and a New Model for the Utility-Regulator Relationship*
17 (July 2012).¹ A copy of my professional resume, which includes my employment history,
18 education, Congressional testimony, regulatory testimony, reports and publications, and
19 professional associations and activities, is attached as Exhibit 1 to this testimony.

¹ Binz, R.J. and D. Mullen, July 2012, *Risk-Aware Planning and a New Model for the Utility-Regulator Relationship*. Available at: <http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf>.

1 **Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC**
2 **SERVICE COMMISSION (“GPSC” OR “THE COMMISSION”)?**

3 A: Yes. I testified in Docket No. 6717-U X Concerning the *Service Provider Selection Plan*
4 of Atlanta Gas Company in January 1997.

6 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

7 A: I was asked by SACE and Southface to review the Georgia Power Company’s (“Georgia
8 Power” or “The Company”) 2022 Integrated Resource Plan (“IRP”) and offer
9 recommendations to the Commission. The purpose of my testimony is to share some of
10 the lessons I’ve learned and insights I’ve gained about planning and procurement that
11 may improve the outcomes of these activities in Georgia. My testimony is based mainly
12 on the experience in Colorado, which has attracted attention nationally as a model for
13 planning and procurement. The Colorado model results in competitive resource
14 acquisitions that benefit utility customers by accomplishing the most important outcomes:
15 lots of bids and low-cost resources.

16 The experience in Colorado is relevant here because the state’s utilities are “vertically
17 integrated,” as they are in Georgia. I think it’s likely that Colorado’s utilities will join an
18 organized market in the next decade. Until then, and in lieu of a competitive wholesale
19 market, the Colorado PUC has refined the practice of using competitive bidding for
20 supply-side resources. As I will develop, there are many benefits associated with a well-
21 designed competitive acquisition process. Respectfully, I think some of Colorado’s
22 experience may be helpful to the Commission.

Q: ARE YOU SUBMITTING EXHIBITS ALONG WITH YOUR TESTIMONY?

A. Yes, I am submitting three (3) exhibits along with my testimony, as follows:

EXHIBIT-1: Curriculum Vitae of Ronald J. Binz.

EXHIBIT-2: Report on All-Source Competitive Solicitations.

EXHIBIT-3: Report on Risk-Aware Electricity Regulation.

II. SUMMARY OF FINDINGS AND CONCLUSIONS

Q: PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW OF GEORGIA POWER'S PROPOSED 2022 IRP AND THE ANALYSIS YOU HAVE CONDUCTED.

1. The energy landscape is in a period of accelerating technological and financial change, driven by much lower-cost, carbon-free technologies and increasing environmental requirements. Utilities must modify their planning, acquisition, and operating practices considering sectoral changes.
2. There are significant flaws in Georgia Power's 2022 IRP and acquisition process which means that the plan submitted in this proceeding will not likely meet the requirements shown in the Company's load forecast in an "economical and reliable manner."² These flaws include:
 - a. Conducting a "limit source" solicitation in which resources are artificially assigned to categories and limited in how much can be selected, in contrast to an "all source" solicitation.

² See generally GA Code § 46-3A-1, 2020.

1 b. Choosing an inappropriate “baseline” scenario in the IRP with respect to, in
2 the Company’s terms, “greenhouse gas pressure” and with respect to its
3 natural gas forecast.

4 c. Incorrect characterization of renewables plus storage for purposes of
5 evaluating those bids.

6 3. Because of these flaws, Georgia Power’s approach to resource determination and
7 acquisition is systematically biased against renewable resources, especially the pairing of
8 solar and storage. The result will be an over-reliance on natural gas, failure to include
9 least-cost resources and likely resulting in higher consumer costs.

10 4. The Commission should withhold approval of the latest-in-time PPA (2028) for capacity
11 at Dahlberg Units 1, 3, and 5. This capacity deficit should either be rolled into the 2025
12 IRP; or, if there is not sufficient time, the Commission should require Georgia Power to
13 conduct a new capacity solicitation prior to the 2025 IRP.

14 5. If the Commission declines to retire some or all the coal units identified for closure, it
15 should reduce the corresponding amount of natural gas PPAs that are sought to be
16 approved in this proceeding.

17 6. The Commission should correct the shortcomings in Georgia Power’s IRP process with
18 explicit requirements in this case for the next IRP. Specifically, the Commission should
19 direct Georgia Power Company to accomplish the following within its next IRP:

20 a. Conduct an “All Source” resource review;

21 b. Require the Company to change the characterization of solar + storage so that the
22 resource can compete fairly in firm energy and firm capacity modeling;

1 c. Include Energy Efficiency and Demand Response as selectable resources in the
2 portfolio modeling in the 2025 IRP; and,

3 d. Adopt a more realistic “baseline” portfolio with respect to “Greenhouse Gas
4 Pressure.”

5 7. The Commission should require Georgia Power Company to increase its use of regional
6 capacity sharing and reflect that in its next IRP.
7

8 **III. TESTIMONY**

9 **Q: WHY IS A COMPETITIVE ACQUISITION POLICY IMPORTANT?**

10 A: Competitive acquisitions reveal the best resources at the best prices by depending on
11 market competition, where buyers and sellers possess sufficient information to transact
12 for their mutual and individual profit. Utility buyers and resource providers, armed with
13 the best information about what they need and what they can provide, can use that
14 information directly, and in competition that sharpens all their pencils. Closely related to
15 competitive acquisition is the need for a planning process that allows least-cost resources
16 to be lined up in a portfolio that is itself least-cost.

17 In the utility sector, where legal monopolies often limit buyers to one utility, competitive
18 results depend, paradoxically, on regulation that is robust enough to substitute for normal
19 competitive market incentives. Even with this important constraint, recent experience in
20 regulated utility competitive acquisition for generation resources shows that impressive
21 results can be obtained in the form of good projects that meet utility needs at low costs to
22 consumers. Again, competitive resource acquisitions through regulated utility planning
23 and procurement gives substantial certainty about both available resources and their

1 costs. Knowledge garnered in competitive markets will be superior to finding prices and
2 availability using either corporate analysis and decision making or regulatory oversight.
3 In this case, markets know best. Absent market competition, the utility's financial
4 incentives may skew outcomes, commission oversight might lack the analytic tools, and
5 staff time may be inadequate.

6 Colorado has developed a nationally recognized utility planning and procurement process
7 that provides the model from which this testimony is developed. That model has been
8 analyzed in detail in several recent reports, so those reports can be relied on to relate the
9 notable features, timelines, and details of the model.³ Those won't be repeated in detail
10 here. Instead, this testimony relates what I hope are useful lessons from experience with
11 the Colorado model.

12
13 **Q: IS IT A GOOD REGULATORY PRACTICE TO HAVE AN EXPLICIT POLICY**
14 **FOR COMPETITIVE RESOURCE ACQUISITION?**

15 **A:** Yes. A clear statement that resources are to be obtained as a result of a competitive
16 process informs everyone – the Commission and staff, utilities, suppliers, and
17 stakeholders. Absent compelling reasons not to use it, competition is the means for
18 acquiring added resources. The Colorado PUC's Rules Regulating Electric Utilities state:

19 *It is the Commission's policy that a competitive acquisition process will*
20 *normally be used to acquire new utility resources. The competitive bid process*
21 *should afford all resources an opportunity to bid, and all new utility resources*

³ E.g., Lawrence Berkely National Laboratory websites on Competitive Procurement, available at: <https://emp.lbl.gov/projects/competitive-procurement>; and Resource Planning and Procurement Trends, available at: <https://emp.lbl.gov/projects/utility-resource-planning>.

1 *will be compared in order to determine a cost-effective resource plan (i.e., an*
2 *all-source solicitation).*⁴

3
4 **Q: PLEASE DESCRIBE THE COMPETITIVE ACQUISITION REGIME USED IN**
5 **COLORADO.**

6 A: Colorado uses an “all-source” competitive acquisition regime. Bidding is open to all
7 technologies and, very importantly, all sizes of projects. The state has been using all-
8 source bidding since at least 2008. The process has been reformed over the course of its
9 use, with the result that the utilities now receive a large number of bids, representing a
10 more complete set of technologies, various ownership models, and a range of in-service
11 dates. Best of all, Colorado’s competitive bidding regime has produced very low prices
12 for a variety of generation technologies. I will present details in the next section of
13 testimony.

14 As an example, Table 1 provides a summary from XcelEnergy’s 2016 Colorado IRP.⁵
15 The prices listed in this table are the *MEDIAN* price for the bids in each category. As we
16 will see later, the eventual contracted prices were even lower than the median bids. These
17 very low prices, especially for solar + storage, surprised many in the utility world and
18 have become the expectation for bids in many states.⁶

⁴ Colorado Public Utilities Commission, *Rules Regulating Electric Utilities*, 4 CCR 723-3 Section 3611 (a).

⁵ In this table, prices are redacted when the number of bidders (1 or 2) is so small that the vendors’ identities could be discovered.

⁶ An effusive utility employee called prices in the 2016 all-source solicitation “incredible.”

Table 1. Median Prices in XcelColorado's 2016 All-Source Solicitation

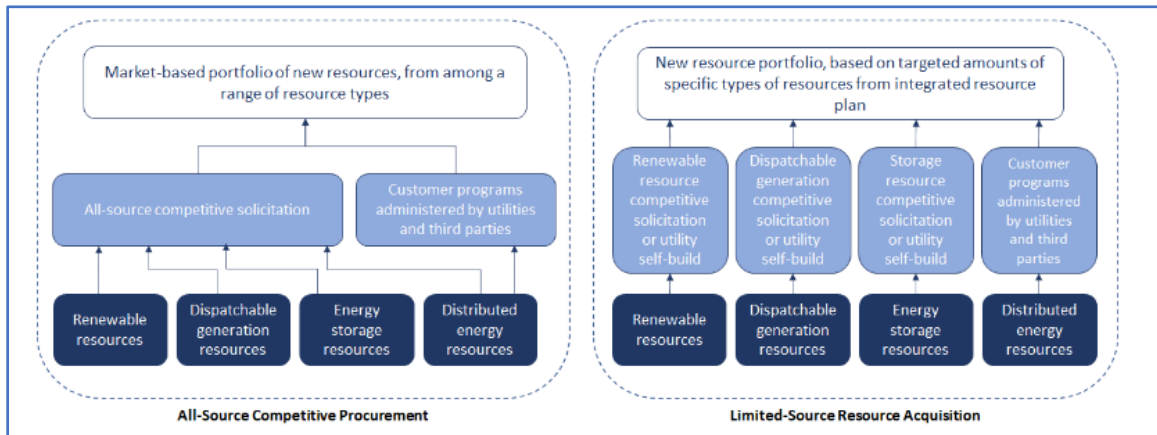
RFP Responses by Technology						
Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	\$ 4.80	\$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	\$/kW-mo
Gas-Fired Combined Cycles	2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

Q: HOW DOES ALL-SOURCE COMPETITIVE ACQUISITION COMPARE TO THE SYSTEM USED BY GEORGIA POWER?

A: Georgia Power conducted separate competitive bids for capacity and renewable resources. Significantly, the company sets a target (limit) on the amount of renewable energy required. The company acquires demand-side management (“DSM”) and demand response (“DR”) resources through a separate process. It is unknown at this point, but we might surmise that the company will conduct a separate process when standalone storage is acquired. The term “limited-source resource acquisition” is applied to this practice. In contrast, all-source bidding accommodates all supply technologies and, in some cases, both supply-side and demand-side resources. Figure 1, below, from a 2021 report

produced for the U.S. Department of Energy by researchers at Lawrence Berkeley National Laboratory, illustrates the differences in these two approaches.⁷

Figure 1. All Source versus Limited Source Procurement



Far preferable would be for Georgia Power to conduct “all-source” bidding, a practice used by progressively more vertically integrated U.S. utilities. Roughly, this is a “bottom-up” approach to assembling a portfolio, compared to the “top-down” methods employed by Georgia Power. With its rich solar resources, there are strong reasons that Georgia regulators should require the state’s utilities to use all-source solicitation.⁸

⁷ Kahrl, F., March 2021, *All-Source Competitive Solicitations: State and Electricity Utility Practices*, Berkeley, CA: Lawrence Berkeley National Laboratory. pp. 59.

⁸ For a helpful discussion of all-source solicitations, see above, included as Exhibit 2.

1 **Q: PLEASE DISCUSS GEORGIA POWER’S 2022 IRP IN LIGHT OF YOUR**
2 **EXPERIENCE AND FINDINGS.**

3 A: The system of bidding and acquisition used by Georgia Power in the *2022-2028 Capacity*
4 *Request for Proposals (“RFP”)*, Docket No. 42641, was flawed and will lead to the
5 acquisition of the wrong resources, with higher costs. I have several concerns about the
6 *2022-2028 Capacity RFP* design decision that eliminated many of the solar projects in
7 the interconnection queue from the pool of eligible bidders. I also have concerns about
8 the manner in which renewable resources are characterized in the Company’s modeling.
9 Further, I have concerns about the Company’s vision for capacity additions over the next
10 18 years. I disagree about the assumptions used by the Company in developing its
11 baseline scenario for capacity expansion. Finally, the entire planning and acquisition
12 process fails to acknowledge or accommodate opportunities for the Company to share
13 reserves in the region.

14
15 **Q: PLEASE BEGIN WITH YOUR CONCERN ABOUT THE TECHNIQUES USED IN**
16 **SOLICITATION AND MODELING BY GEORGIA POWER.**

17 A: I have two. First is the design of Georgia Power’s *2022-2028 Capacity-Based RFP*
18 resulting power purchase agreements (“PPAs”) under discussion in this case. In seeking
19 bids for capacity, the Company set a minimum bid offer at 100 MW.⁹ This had the effect
20 of removing an estimated seventy-four solar projects (with storage or storage-capable)
21 from contention in the bidding. Few solar + storage projects in 2019 exceeded the
22 100 MW size limitation. Capacity offerings smaller than 100 MW were not considered,

⁹ *Georgia Power’s 2022-2028 Capacity-based RFP*, Docket No. 42641.

1 even though many of them might well have been lower cost than the resources that were
2 selected, but the Commission will never know.

3 Second, in Georgia Power's *2022-2028 Capacity-Based RFP* solicitation, various types
4 of resources are assigned to their own bidding pool in line with the characterization of the
5 resource by Georgia Power. Solar + storage bids were allowed to bid in but were
6 characterized and evaluated as if they were merely batteries charged by intermittent
7 power. Analyzed this way, solar + storage bids are seen as little combustion turbines, but
8 with higher costs and producing energy that the Company was not interested in buying.

9 Consider this excerpt from the *2022-2028 Capacity-Based RFP*:

10 It is imperative for any potential bidder proposing a Storage Bid to understand the
11 exclusive purpose of a BESS in this Capacity RFP is to satisfy Seller's capacity
12 obligations under the PPA and to satisfy Seller's obligations under the PPA to
13 deliver energy that is not intermittent to the Point of Interconnection pursuant to
14 the Company's scheduling instructions. The storage use case applicable to a
15 BESS in this capacity RFP is unlike the storage use case applicable to a battery
16 storage bid offered in any Company solicitation for renewable resources. The pro
17 forma PPA found in Attachment F3 and the additional guidance for BESS
18 proposals in Attachment L provide the parameters for the acceptable and
19 applicable use of the storage device in this capacity RFP. Evaluation of a Storage
20 Bid in this RFP will be appropriately focused upon the capacity use of the BESS,
21 which is to serve as a satisfactory replacement resource for any retiring capacity

1 resource to ensure system reliability. It is not the intent of this RFP to increase the
2 amount of intermittent energy being delivered to the grid.¹⁰

3 This scheme distinctly disadvantages solar + storage projects. Solar + storage resources
4 are not seen as renewable resources whose output is “firmed up” by batteries. The
5 capacity value brought by a solar project during its peak generation period (say 10AM to
6 4 PM) is disregarded in this scheme in favor of the size of the project’s battery. Because
7 many solar + storage facilities size their batteries at one-fourth to one-half the facility’s
8 capacity, this limits the capacity value assigned by Georgia Power to about one-fourth to
9 one-half the facility’s firm capacity during its generating hours. This arbitrary limit is
10 divorced from the reality of how these systems operate. As discussed more below, this
11 characterization of solar + storage unreasonably excludes competitive resources from
12 competing on level playing field.

13 The root problem is the Company’s apparent view of variable renewable resources.
14 Georgia Power seems to regard variable renewable resources, even with storage, from the
15 perspective of a fossil-fueled utility with a rigid operating approach. Although the
16 Company conducted two recent RFPs – one for renewables and one for capacity – this
17 method relegates solar generation to being an “energy resource.” In fact, elsewhere stand-
18 alone solar is often accorded a capacity value and solar + storage has many of the
19 qualities of grid dynamics that provide a firm or near-firm resource with both (clean)
20 energy and capacity.

21 This attitude is progressively more at odds with how other utilities are approaching the
22 availability of low-cost renewables. What’s needed is a shift of perspective about how a

¹⁰ Id., Page 7.

1 grid can be built and operated with progressively larger amounts of variable renewable
2 energy. This is not the time and place to describe a new operating regime, but we can
3 look to other utilities for some ideas.

4 XcelEnergy in Colorado made the transition from the rigid, inflexible approach to a
5 planning and operating regime that makes full use of variable renewable resources,
6 without, importantly, sacrificing any bit of reliability. XcelEnergy's orientation to a novel
7 approach was first made necessary as the company acquired massive amounts of very
8 low-cost wind power. As the price of solar + storage plunged to an "incredible" price
9 level, XcelEnergy began loading-up on wind and solar + storage in its "all-source"
10 bidding regime.

11 It's unclear how Georgia Power evaluates solar and storage. The Company apparently
12 models both solar generation and battery energy storage on a standalone basis, even
13 though solar photovoltaics ("PV") and energy storage systems ("ESS") are often
14 designed and operated as a single entity. Such integration allows solar + storage to
15 capture the brass ring of "dispatchability," which makes such units competitive with firm
16 fossil generation. Of course, these plants may not be "dispatchable" in the middle of the
17 night, but this does not diminish their value during peak periods on the system. Whatever
18 techniques are used, it's clear that designing and operating an integrated solar + storage
19 facility in real life is quite different than putting together standalone solar bids and
20 standalone ESS bids on a spreadsheet. Because solar + storage resources operate as a
21 single unit, separating them in analysis denies the projects of the economies of joint
22 operation and, financially, the benefit of federal tax treatment that applies to solar +
23 storage, but not to standalone ESS. Put simply, divorcing PV and ESS resources from one

1 another, when they are operated as a single facility, is an unreasonable approach and
2 represents a significant flaw within Georgia Power's procurement process. For these
3 reasons, solar + storage loses out to combustion turbines ("CT") in the capacity RFP,
4 while storage handicaps these projects in the renewables RFP.
5

6 **Q: PLEASE DISCUSS THE SYSTEM EXPANSION SCENARIOS PRESENTED BY**
7 **GEORGIA POWER AND COMMENT ON THE UNDERLYING ASSUMPTIONS.**

8 A: We begin with one table and one figure. First, Table 2 is taken from the Georgia Power's
9 2022 IRP Main Document, page 7-34. It shows the assumptions used in modeling,
10 consisting of a range of values for natural gas prices, cost of carbon, technology
11 breakthroughs, etc. In a column on the right, beside the original table, I inserted a column
12 of the net present value of the costs (in \$000) for each scenario.¹¹

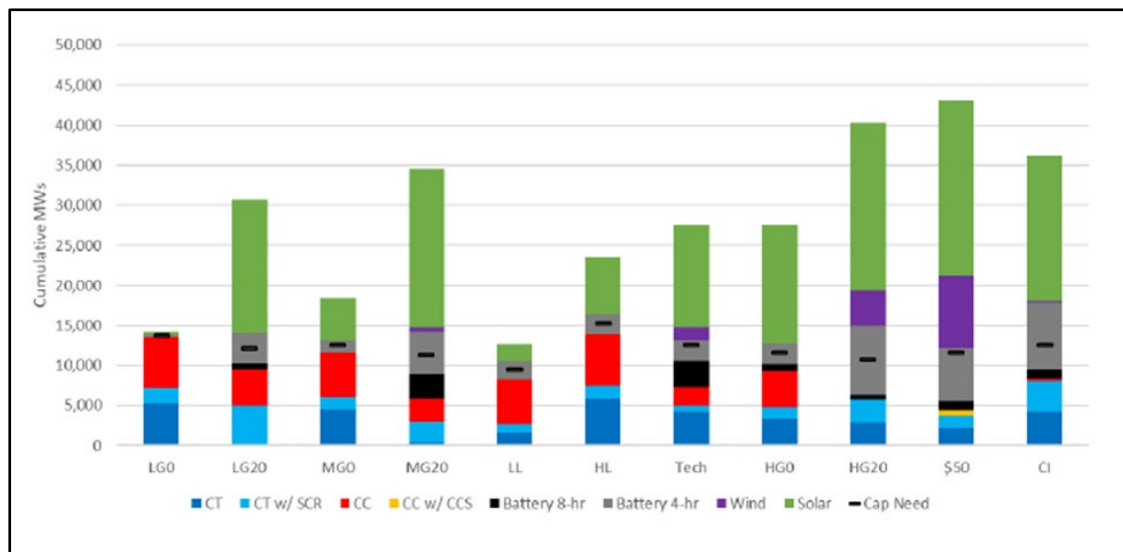
¹¹ *Georgia Power's 2022 Integrate Resource Plan*, Docket No. 44160, Technical Appendix PD Volume 1, Resource Mix Study. Data from the "SystemCost" tab of PD Capacity Expansion Plans.xlsx.

Table 2. Georgia Power's B2022 Scenario Design

Scenario	Natural Gas View	Greenhouse Gas Pressure View	Technology Cost & Performance View	Load View	Short Name	
1	Moderate price path	\$0 fee	SCS Gen-Tech App Stds ¹	SCS Forecasting ²	MG0	\$85,030,713
2	Moderate price path	\$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + MG20 delta	MG20	\$100,503,384
3	\$50 CO ₂ price path	\$50+ fee	SCS Gen-Tech App Stds	SCS Forecasting + \$50 delta	\$50	\$122,576,545
4	Low price path	\$0 fee	SCS Gen-Tech App Stds	SCS Forecasting + LG0 delta	LG0	\$81,093,045
5	Low price path	\$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + LG20 delta	LG20	\$97,864,889
6	High price path	\$0 fee	SCS Gen-Tech App Stds	SCS Forecasting + HG0 delta	HG0	\$97,385,835
7	High price path	\$20+ fee	SCS Gen-Tech App Stds	SCS Forecasting + HG20 delta	HG20	\$109,616,018
8	Moderate price path	\$0 fee	SCS Gen-Tech App Stds	Electrification-influenced load growth ³	HL ³	\$94,335,820
9	Moderate price path	\$0 fee	SCS Gen-Tech App Stds	DER/EE-influenced load growth ⁴	LL ⁴	\$72,792,713
10	Moderate price path	\$0 fee	Lower costs of zero-CO ₂ technologies ⁵	SCS Forecasting	Tech	\$82,545,874
11	Moderate price path	2050 CO ₂ Intensity ⁶	SCS Gen-Tech App Stds	SCS Forecasting	2050 CI	\$100,631,900

Second, Figure 2 is a graph showing the generic capacity expansion plans associated with each of the scenarios listed in Table 2. Unfortunately, the columns on the graph in Figure 2 are not in the same order as the rows in Table 2, but they can be matched using the scenario "Short Name."

Figure 2. Georgia Power's Expansion Plan Results



For example, the net present value of the costs of the first scenario in Table 2 is \$85,030,713. The “Short Name” for this scenario is “MG0”. Moving to the bar chart in Figure 2, we see that “MG0” corresponds to the third bar from the left in the chart.

Q: WHAT DO THESE TWO FIGURES TELL YOU ABOUT GEORGIA POWER’S PLANNING AND MODELING?

A: First note that the capacity expansion plans for these eleven scenarios vary widely in terms of the resources that are selected in the modeling. Compare MG0 (medium gas cost, zero carbon price) with MG20 (medium gas cost, \$20/ton carbon price). In Figure 2, the MG0 column shows substantial amounts of generation from CTs and combined cycle gas plants (“CC”). Compare that with scenario MG20, the next column to the right of MG0. The CTs have dropped out of the mix, replaced by (fewer) CTs with steam Rankine cycle (“SCR”); the amount of CC generation is reduced by about 60%; 8-hour batteries show up as a selected resource and the use of 4-hour batteries quadruples; finally, the amount of solar capacity more than triples.

To emphasize, changing *only* the assumption that a \$20/ton cost of carbon is adopted or imposed, compared to Georgia Power’s assumption of \$0/ton, fundamentally changes the suite of resources selected.

1 **Q: DO YOU THINK GEORGIA POWER IS PRUDENT TO ADOPT THE MG0**
2 **(MEDIUM GAS PRICE, \$0 CARBON COST) CASE AS ITS BASELINE?**

3 A: It is a risky choice in view of what we know about the United States’ emphasis on
4 decarbonization and reduction of CO₂ pollution. Consider that each of these scenarios is
5 “least cost” given the input assumptions. Comparing MG0 with MG20, the consumers of
6 Georgia Power are at risk of higher costs if the future turns out to be different than a zero-
7 carbon price. The Company will be stuck with CTs that will need to be retrofitted, CCs
8 that are “out of the money” compared to other resources, while having acquired almost
9 no batteries. The Company will be able to function, of course, but with higher costs than
10 necessary.

11
12 **Q: WHAT ASSUMPTIONS ARE OTHER STATES AND UTILITIES MAKING**
13 **ABOUT GREENHOUSE GAS PRESSURE?**

14 A: A trend among states is toward using a cost of carbon that is much higher than zero.
15 Carbon prices assumed for modeling are often in the range of \$20 to over \$50 per ton of
16 CO₂, depending on the jurisdiction. To emphasize, this value is used as an input to
17 resource modeling: it is not simply added to the cost of power. Colorado uses a price of
18 \$47 per ton; New York uses \$51 per ton; Virginia, Maryland, North Carolina, California,
19 Nevada, Illinois, Minnesota, Maine, New Jersey, Vermont, and Washington state all tie
20 carbon price assumptions directly or indirectly to estimates of the social cost of carbon
21 emissions. Imputing this cost of carbon aids in making choices about resources for the
22 future and adds to the economic logic about retiring existing fossil facilities.

1 **Q: PLEASE DESCRIBE ANOTHER SCENARIO DEVELOPED BY GEORGIA**
2 **POWER -- “AGGRESSIVE DSM” – THAT WAS NOT DISPLAYED IN THE**
3 **COMPANY’S SUMMARY IN TABLE 2.**

4 A: In the addition to the eleven scenarios listed in Table 2, Georgia Power priced out a
5 scenario in which DSM was aggressively pursued. The details of the resulting scenario
6 are contained in a confidential exhibit and will not be discussed here. However, we do
7 know the cost of the Aggressive DSM scenario. It turns out that the net present value of
8 the cost of the Aggressive DSM scenario is \$81,948,961. This is lower than the cost of
9 the Company’s baseline scenario MG0 (\$85,030,713), and it is the second lowest of all
10 fourteen scenarios described in the Company’s filing. Only LG0 (low-cost natural gas,
11 zero cost of carbon) was slightly lower cost than the Aggressive DSM scenario.

12 There are at least two important implications of this analysis. First, this is a modeling
13 demonstration that DSM is indeed a least-cost resource. Second, it shows the importance
14 of including DSM as a selectable resource in future IRP modeling. If the Commission
15 directs Georgia Power to undertake an all-source solicitation in future IRPs, then the
16 power of that future analysis will be improved by inclusion of DSM as a “resource.”

17
18 **Q: PLEASE DISCUSS THE COMPANY’S VIEW OF LONG-TERM FUTURE**
19 **CAPACITY RESOURCES BEYOND WHAT IT IS SEEKING APPROVAL FOR**
20 **IN THE CURRENT IRP CYCLE.**

21 A: The shortcomings of the Company’s approach become manifest when we examine its
22 vision of the Georgia Power’s grid over the period 2022-2041. Consider Figure 3, below,
23 taken from the PD Capacity Expansion Plans spreadsheet in the Resource Mix Study of

1 the Company's 2022 IRP filing, modified to show the addition of the capacity resources
2 for which approval is sought in this case.¹² The capacity entries under CT and CC for
3 2024, 2025, and 2028 have been added to the Company's original exhibit. The dotted-line
4 rectangle captures all the capacity resources that are envisioned for the Georgia grid from
5 now until 2036.

6 What is most striking about this figure is that the Company envisions adding 8,875 GW
7 of natural gas capacity and energy in the next twelve years, before any solar capacity is
8 added in 2037. As I understand it, Georgia Power is not asking the Commission for
9 approval of this vision now; movement towards this future will occur, if at all, through
10 subsequent IRP proceedings. This glimpse at the future shows that, between now and
11 2041, 72% of its incremental generation capacity needs will be met by gas units, and only
12 28% will be met with solar generation, with that coming at the end of the period.

¹² *Georgia Power's 2022 Integrate Resource Plan*, Docket No. 44160, Technical Appendix PD Volume 1, Resource Mix Study. Data from the "SystemCost" tab of PD Capacity Expansion Plans.xlsx.

Figure 3. Georgia Power's Baseline Capacity Expansion Plan 2023-2041

Capacity Expansion Plan - MG0 (GPC Only)																
Incremental																
Year	CT	CT w/ SCR	CC	CC w/ CCS	Solar	Wind	Battery 4- hr (T1)	Battery 4- hr (T2)	Battery 4- hr (T3)	Battery 4- hr (T4)	Battery 8- hr	Recip	Nuclear 1	Nuclear 2	Super CO2	Total
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	309	-	1,258	0	0	0	0	0	0	0	0	0	0	0	0	1567.3
2025	380	-	-	0	0	0	0	0	0	0	0	0	0	0	0	380
2026	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	228	-	-	0	0	0	0	0	0	0	0	0	0	0	0	228
2029	1,110	-	-	0	0	0	0	0	0	0	0	0	0	0	0	1110
2030	510	-	-	0	0	0	0	0	0	0	0	0	0	0	0	510
2031	2,190	-	-	0	0	0	0	0	0	0	0	0	0	0	0	2190
2032	120	-	-	0	0	0	0	0	0	0	0	0	0	0	0	120
2033	390	-	-	0	0	0	0	0	0	0	0	0	0	0	0	390
2034	180	-	-	0	0	0	0	0	0	0	0	0	0	0	0	180
2035	-	-	2,310	0	0	0	300	0	0	0	0	0	0	0	0	2610
2036	-	-	1,800	0	0	0	300	600	300	0	0	0	0	0	0	3000
2037	0	0	240	0	540	0	0	0	0	0	0	0	0	0	0	780
2038	0	0	750	0	1320	0	0	0	0	0	0	0	0	0	0	2070
2039	0	210	510	0	1320	0	0	0	0	0	0	0	0	0	0	2040
2040	0	780	0	0	1320	0	0	0	0	0	0	0	0	0	0	2100
2041	0	510	0	0	840	0	0	0	0	0	0	0	0	0	0	1350
	5417	1500	6868.3	0	5340	0	600	600	300	0	0	0	0	0	0	20625.3

8,785 MW of gas generation (CTs and CCs) are added before any solar capacity is added in 2037.

Q: WHAT ARE YOUR THOUGHTS ON THIS MG0 EXPANSION PLAN SCENARIO?

A: This appears to me to violate all principles of risk management. The Company seems content to put all its capacity eggs in one basket during the 15 years from now until its model says solar capacity is added. Earlier I discussed the fuel risk associated with fossil generation, especially when the fossil generation relies on a single fuel. No one can predict future natural gas prices with certainty. With that in mind, generation diversity is the best mechanism to deal with fuel risk.

The modeling result that leads to Scenario MG0 occurs for three reasons, each of which is within the control of the Company: 1) solar + storage is effectively disqualified from the 2022-2028 *Capacity-Based RFP* because of its characterization as nothing more than a battery; 2) the Company assumes that there is zero probability of higher carbon costs

1 affecting its baseline fossil portfolio; 3) there has been insufficient consideration of the
2 risk of upward trends and fluctuations in the cost of natural gas.

3 Bottom line, the Company asks us to believe that natural gas generation will be a least-
4 cost resource throughout the period under discussion. But in many places, solar + storage
5 projects are cost competitive with fossil generation today, not in theory, but in actual grid
6 operations. Even if there is debate about its competitiveness in 2022, solar + storage
7 technology bundles will certainly be least cost by 2030. All the while, the Company's
8 view is that gas generation will be chosen for capacity under its baseline scenario.
9 Importantly, this position appears not to contemplate additional limits on greenhouse gas
10 emissions that may be put in place during the next eight years, or possible fluctuations in
11 natural gas prices.

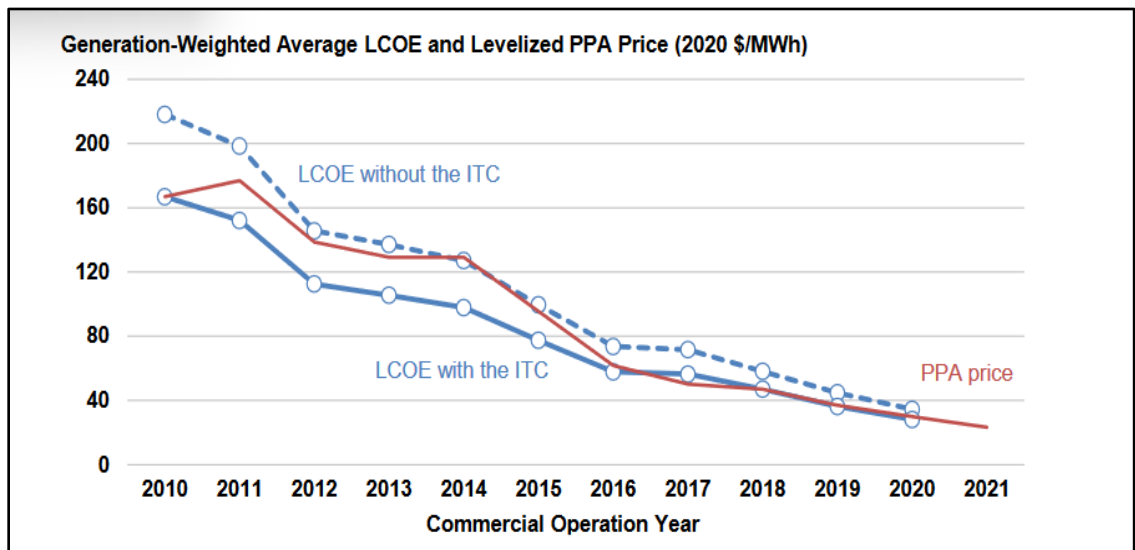
12
13 **Q: HAVE YOU REVIEWED THE SOLAR + STORAGE PROJECTS IN THE**
14 **GEORGIA POWER INTERCONNECTION QUEUE?**

15 **A:** Yes, I have. As of April 22, 2022, the interconnection queue contained a total of
16 15,975 MW of solar projects, three-quarters of which are solar + storage projects. Many
17 of these projects began as solar-only and have been re-designed to include storage.
18 Twenty-eight of the projects are smaller than 100 MW, while eighty-four are larger than
19 100MW. Collectively, the solar + storage projects in the interconnection queue represent
20 a huge, low-cost resource for Georgia Power. But unless the Company modifies its vision
21 and methods for building a portfolio, these projects, and others to follow, have nowhere
22 to go.

Q: WHAT DOES THE NEAR FUTURE HOLD FOR SOLAR + STORAGE IN GEORGIA?

A: It is worth examining the cost of solar + storage bids the Company is likely to receive if it pursued an “all source” bidding regime as discussed earlier. From page 10-66 of the IRP Main Document, we know that Georgia Power estimates stand-alone solar generation currently to cost between \$20 and \$25 per MWh.¹³ These estimates are supported by much industry literature, including a recent presentation and report by the Lawrence Berkeley National Laboratory (“LBNL”).¹⁴ Figure 4 documents the dramatic decline in utility-scale solar costs.

Figure 4. Lawrence Berkeley National Laboratory’s Solar LCOE History



¹³ Georgia Power’s 2022 Integrated Resource Plan, Docket No. 44160, Main Document, Page 10-66.

¹⁴ Bolinger, M., J. Seel, S. Robson, and C. Warner, November 2020, *Utility Scale Solar Data Update: 2020 Edition*, Berkeley, CA: Lawrence Berkeley National Laboratory. pp 57. Available at: https://emp.lbl.gov/sites/default/files/2020_utility-scale_solar_data_update.pdf

To estimate the added cost of battery storage, we can consult the XcelEnergy Colorado bids and other sources. Table 3, below, lists the actual contracted solar and solar + storage resources scheduled to be in service in 2022.¹⁵

Table 3. Contracted Prices from XcelEnergy Colorado's 2016 All-Source RFP

Bid ID	Project Name	Bidder Name	In-Service Year	Nameplate Capacity (MW)	Storage (MW)	Structure	Contract Term (yr)	45 DAY LEC (\$/MWh)	45 DAY LCC (\$/kW-mo)
W602	Bronco Plains Wind	NextEra	2020	300		PPA	25	\$ 10.68	\$ -
W192	Cheyenne Ridge	Tradewind	2020	500		Build-Own Transfer		\$ 16.53	\$ -
W301	CO_Green_162	Avangrid	2020	162		PPA	20	\$ 14.16	\$ -
W090	Mountain Breeze	Leeward	2020	169		PPA		\$ 18.00	\$ -
S430	Owl Canyon PV	Coronal	2022	75		PPA		\$ 22.53	\$ -
S085	Hartsel Solar	Adani	2022	72		PPA	25	\$ 26.84	\$ -
X647	Thunder Wolf	NextEra	2022	200	100	400 PPA	25	\$ 30.32	\$ -
X427	Piccadilly Solar + Storage	Coronal	2022	110	50	100 PPA		\$ 30.33	\$ -
X645	Neptune	NextEra	2022	250	125	500 PPA	25	\$ 31.35	\$ -
G215	Manchief Gas Combustion Turbine	Atlantic	2022	301		Existing Asset Sale		\$ -	\$ 150
G065	Valmont Gas Plant 2022	SW Generation	2022	82		Existing Asset Sale		\$ -	\$ 2.43

The two signed solar PPAs *without* storage average \$24.69/MWh, very close to the Georgia Power planning estimates for standalone solar resources. The two solar + storage projects have an average cost of \$30.84/MWh for four-hour battery storage at one-half the PV project's capacity. This means the average extra cost associated with storage is \$6.15/MWh. Revisiting Table 1, on page 11, which shows the median prices of all the bids XcelEnergy Colorado received, we see that the median extra cost associated with storage is similar, at \$6.50/MWh. These figures are also similar to estimates made by

¹⁵ E.g., Trabish, H.K., June 2021, *Xcel's Record-Low-Price Procurement Highlights Benefits of All-Source Competitive Solicitations*, UtilityDive.com. Available at: <https://tinyurl.com/y4d4re5c>.

1 LBNL.¹⁶ For 4-hour battery storage with a capacity of half the PV capacity, LBNL
2 estimates the extra cost to be about \$10/MWh.¹⁷

3 Putting this all together, we should expect that solar + storage bids will be in the range of
4 \$26.50/MWh to \$35/MWh. To emphasize, these resources are being relied upon by
5 utilities across the country, but apparently not by Georgia Power. And to put these prices
6 in context, the GPSC staff estimates that power from Vogtle Units 3 and 4 will cost about
7 five times as much, at \$150/MWh.¹⁸

8
9 **Q: ARE YOU RECOMMENDING THAT THE COMPANY REDO THE**
10 **SOLICITATION AND MODELING TO ACCOMMODATE THE MATTERS YOU**
11 **IDENTIFIED?**

12 A: No. Staying with the farm analogy, that horse is out of the barn. Bids have been solicited
13 and evaluated; contracts have been negotiated. However, I think the Commission should
14 consider two potential off-ramps to the acquisition.

15 First, the last of the contracts for 256 MW from three units at Dahlberg will not go into
16 effect until 2028, two years after a new IRP in 2025. The Commission should consider
17 putting-off a decision on this last tranche of capacity until the next IRP. Alternatively, if
18 the Commission concludes there would not be enough time in Georgia Power's 2025 IRP
19 process to treat this 2028 capacity shortfall, it should require a new capacity solicitation

¹⁶ Bolinger, M., J. Seel, S. Robson, and C. Warner, November 2020, *Utility Scale Solar Data Update: 2020 Edition*, Berkeley, CA: Lawrence Berkeley National Laboratory. pp 57. Available at: https://emp.lbl.gov/sites/default/files/2020_utility-scale_solar_data_update.pdf.

¹⁷ *Id.*, Page 30.

¹⁸ *Georgia Power's Twenty-Fifth Semi-Annual Vogtle Construction Monitoring ("VCM") Report*, Docket No. 29849, Direct testimony of GPSC Staff Tom Newsome, Philip Hayet, and Lane Kollen before the Commission on December 1, 2021.

1 in advance of the 2025 IRP. With appropriate adjustments to the solicitation process,
2 discussed below, the Commission will have added information about the need for
3 capacity from these three combustion turbines.

4 In a similar vein, if the Commission determines in this case not to retire some of the coal
5 plants proposed for closure, then the Commission should not approve PPAs for capacity
6 the Company says are needed to make up for the closed plant capacity. During Georgia
7 Power's 2025 IRP, the Commission can examine the revised capacity needs and direct
8 the Company to undertake a new solicitation.

9
10 **Q: YOU MENTIONED GEORGIA POWER'S RELATIONSHIP TO OTHER**
11 **CAPACITY IN THE REGION. PLEASE COMMENT.**

12 **A:** In Georgia Power's 2022 IRP, the Company is proposing a 16.5% reserve margin in
13 summer and a 26% reserve margin in winter. Needless to say, these proffered reserve
14 margins are high and very expensive.

15 One traditional way to reduce reserve margins is to broaden the footprint over which the
16 reserve requirement is measured. For this reason, Regional Transmission Organizations
17 ("RTOs") and Independent System Operators ("ISOs") tend to have lower reserve
18 margins because there is extensive reserve sharing among the members. In case of
19 Georgia Power, there is very little mention of its opportunities for reserve sharing
20 discussed in this IRP. Appendix G to the IRP filing discusses the Intercompany
21 Interchange Contract that allows reserve sharing among Southern Company members.
22 While this exchange is undoubtedly helpful, it would have much less impact than an RTO
23 or a region-wide power pool (such as those that preceded the formation of RTOs). I am

1 aware of the public discussion about forming an RTO in the southeast region, and do not
2 propose to get involved in the associated political and economic debates. Looking to the
3 near future, regional cooperation and reserve sharing will assume even greater
4 importance as the operating companies of the Southern Company begin taking on
5 increasing levels of variable renewable energy. Suffice it to say, the Commission should
6 push for as much regional cooperation as can be achieved.

7
8 **Q: PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS FOR**
9 **THE COMMISSION.**

- 10 1. The energy landscape is in a period of accelerating technological and financial change,
11 driven by much lower-cost carbon-free technologies and increasing environmental
12 requirements. Utilities must modify their planning, acquisition, and operating practices in
13 light of sectoral changes.
- 14 2. There are significant flaws in Georgia Power's 2022 IRP and acquisition process which
15 means that the plan submitted in this proceeding will not likely meet the requirements
16 shown in the Company's load forecast in an "economical and reliable manner."¹⁹ These
17 flaws include:
- 18 a. Conducting a "limit-source" solicitation in which resources are artificially
19 assigned to categories and limited by how much can be selected.
- 20 b. Choosing an inappropriate "baseline" scenario in the IRP with respect to, in the
21 Company's terms, "greenhouse gas pressure" and its natural gas forecast.

¹⁹ See generally GA Code § 46-3A-1, 2020.

1 c. Incorrect characterization of renewables plus storage for purposes of evaluating
2 those bids.

3 3. Because of these flaws, Georgia Power's approach to resource determination and
4 acquisition is systematically biased against renewable resources, especially the pairing of
5 solar + storage. The result will be an over-reliance on natural gas, failure to include least-
6 cost resources, and likely higher costs than otherwise.

7 4. The Commission should withhold approval of the latest-in-time PPA (2028) for capacity
8 at Dahlberg Units 1, 3, and 5. This capacity deficit should either be rolled into Georgia
9 Power's 2025 IRP; or, if there is insufficient time, the Commission should require
10 Georgia Power to conduct a new capacity solicitation *prior to* the 2025 IRP.

11 5. If the Commission declines to retire some or all of the coal units identified for closure, it
12 should reduce the corresponding amount of natural gas PPAs that are sought to be
13 approved in this proceeding.

14 6. The Commission should correct the shortcomings in Georgia Power's IRP process with
15 explicit requirements in this case for the next IRP. Specifically, the Commission should
16 direct Georgia Power Company to accomplish the following within its next IRP:

17 a. Conduct an "All-Source" resource review;

18 b. Change the characterization of solar + storage so that the resource can compete
19 fairly in firm energy and firm capacity modeling;

20 c. Include energy efficiency ("EE") and DR as selectable resources in the portfolio
21 modeling in the 2025 IRP;

22 d. Adopt a more realistic "baseline" portfolio with respect to "Greenhouse Gas
23 Pressure."

1 7. The Commission should require Georgia Power to increase its use of regional capacity
2 sharing and reflect that in its next IRP.

3
4 **Q: WHAT ARE SOME OF THE BASIC REQUIREMENTS FOR ACHIEVING**
5 **WORKABLY COMPETITIVE RESULTS WHEN UTILITIES ARE REQUIRED**
6 **TO ACQUIRE RESOURCES THROUGH COMPETITIVE BIDDING?**

7 A: In my view, three requirements are essential.

- 8 ○ First, there must be strong links between planning and procurement to provide
9 information to bidders;
- 10 ○ Second, utility incentives must be recognized and appropriately regulated; and
- 11 ○ Third, the Commission must be committed to competitive bidding and must have
12 the capacity to oversee a credible process.

13 It goes without saying that a competitive bidding process needs to attract as many bidders
14 as possible. Linking the utility's planning process to its resource procurement provides
15 information on which bidders can rely in preparing their bids. The more informed bidders
16 are, the more likely they will bid their best projects and prices.

17 In Colorado, the process of planning and bidding takes place about every four years, so
18 repetition has helped to improve understanding of how the process works. Planning is
19 done in the first phase of the process; procurement is phase two. Each phase culminates
20 in Commission approvals after hearings, first on all the planning issues that define
21 resource portfolios on which bids are to be requested, and second on the results of the
22 bidding, defining resource portfolios that are to be secured from among the bid-in
23 projects.

1 Colorado's planning requirements are extensive. The issues are fully explored in
2 discovery, testimony, and cross-examination, and characterized in parties' briefs. Draft
3 RFPs, PPAs, bid evaluation, and both existing and potential new resources are at issue in
4 the planning process. The planning phase provides a well-developed determination of
5 what resources are needed, when and why, so both utilities' and bidders' expectations are
6 well informed in detail. Most of the issues that might be contestable and result in legal
7 disputes are resolved up-front in the contested planning case. This means that a broad and
8 detailed Commission order avoids subsequent litigation concerning bids, bid evaluation,
9 and resulting resource portfolios.

10 The results of these planning and procurement processes in Colorado have attracted
11 national attention because lots of bids and low prices have resulted from a workably
12 competitive process.²⁰ In Colorado, since 2013, utility sponsored analysis has shown that
13 adding more wind and solar to utility resource portfolios lowers cost of service for
14 customers. I will return to the details below.

²⁰ To review the Public Service Company of Colorado's bid results report to the Colorado PUC, see: <https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html>. This report provides the basis for trade press stories about *median* wind prices bid at \$18 per MWH. In addition, Colorado's process has been recognized as "best practice" in recent analyses by a variety of sources, including:

1. Exhibit 2 attached to my testimony.
2. Wilson, J., M. O'Boyle, R. Lehr, and M. Detsky, April 2020, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*. San Francisco, CA: Energy Innovations. pp 63. Available at: https://cleanenergy.org/wp-content/uploads/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices_EI_SACE.pdf?msclkid=f81081acbe7211ec973f0aca3b2a1050.
3. Anderson, M., M. Dyson, G. Glazer, C., Linvill, and L., Shwisberg, 2018, *How to Build Clean Energy Portfolios: A Practical Guide to Next-Generation Procurement Practices*. Boulder, CO: Rocky Mountain Institute. Available at: https://rmi.org/wp-content/uploads/dlm_uploads/2021/02/rmi_how_build_ceps.pdf

1 **Q: WHAT IS THE ROLE OF RESOURCE DIVERSITY IN MANAGING RISKS OF**
2 **HIGHER ENERGY PRICES?**

3 A: While lots of bids and low prices are important competitive acquisition outcomes, the
4 planning and procurement process in Colorado delivers another important outcome:
5 diversity of resources. Utilities are rightfully concerned about operational reliability.
6 Colorado's experience, predominantly with wind, but currently incorporating more solar
7 and storage projects, shows that integrating these new resources can be accomplished at
8 low cost while maintaining reliable service. At modest penetration levels, variable
9 renewable resources can provide reliable service if utilities adjust their operating
10 procedures.

11 Colorado's planning process entertains concerns about key electric sector risks, such as
12 fuel costs, environmental regulations, interest rates and cost of money, and load forecasts.
13 By incorporating lessons from financial economics, generation and demand side
14 portfolios can be created that balance risks and rewards in terms that are familiar to
15 investment and financial professionals. Indeed, the energy sector has borrowed the term
16 "portfolio" from financial economics where it is applied to collections of financial
17 investments created to provide maximum returns at minimum risks. Risk-aware utility
18 planning has a shorter history but has definite advantages supporting good decision
19 making and avoiding large scale resource investment mistakes.

Q: WHAT DO YOU MEAN BY “RISK-AWARE REGULATION?”

A: Almost ten years ago, shortly after leaving the Colorado PUC, I was lead author on a report about risk-aware regulation (“Risk-Aware Report”).²¹ The report was the product of four individuals, including two former regulators, a utility bond analyst, and an energy policy specialist. The premise is simple: state regulators are accustomed to regulating *rates* of utilities. Given the complexity of the utility world, regulators must expand their examination to the *risk* of resource choices made by utilities. The *Risk-Aware Report* was embraced by regulators and became a valuable tool for effective regulation. Our report’s recommendations are summarized in Figure 5. I have also attached a copy of the report as Exhibit 3.

Figure 5. Seven Essential Strategies for Regulators to Minimize Risk



²¹ Binz, R.J., R. Sedano, D. Furey, and D. Mullen, April 2012, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, Boston, MA: Ceres. pp. 55.

1
2 In the years since the report's publication, I have arrived at the opinion that, of the seven
3 strategies, the first and second are the most important: seeking to diversify the utility's
4 supply portfolio and engaging in a robust planning and acquisition regime.

5
6 **Q: HOW DO COMPETING TECHNOLOGIES AND PROVIDERS PROMOTE RISK-**
7 **AWARE REGULATION?**

8 A: Renewable resources play a key role in managing cost and risk. The *Risk-Aware Report*
9 was produced at a time when renewable energy products were just beginning to catch up
10 to traditional supply-side options on cost. As the Commission is aware, that process has
11 accelerated tremendously in the past several years. Resources that could once be justified
12 only by appealing to their environmental externalities now compete directly with
13 traditional resources on cost. And, as developed in the *Risk-Aware Report*, renewable
14 resources and energy efficiency are lowest risk. But we are still in a transition. Utilities
15 and regulators are challenged to adapt to a new paradigm: what many once saw as fringe
16 resources are now becoming mainstream and are poised to replace fossil resources in the
17 near future.

18 Besides reducing risk and lowering costs, risk-aware planning has another important
19 benefit. New wind, solar, and storage resources are not only becoming least-cost, but they
20 are also almost completely defined by their capital costs. There is no fuel cost and very
21 low Operation and Maintenance ("O&M") costs for these resources; once their capital
22 costs are invested, their marginal cost of energy is very low and can be relied on with

1 certainty. Similarly, these projects' capital costs are determined by the cost of money
2 needed for capital. Lower cost of money for these projects means lower cost of energy.

3 There is a case developing that suggests that these projects will achieve relatively lower
4 costs of capital than competing resources, because investors, who determine their costs
5 for investing or lending funds based on their risk profiles, are more interested in lower
6 carbon and less climate intensive investments that present less climate risk.²² As
7 disclosure requirements become more common and extensive, investors will have more
8 information about these relevant risks.²³

9
10 **Q: HOW CAN REGULATORS HARNESS THE CHANGING SITUATION?**

11 A: Regulators need not take anyone's opinions on faith. The cost competitiveness of any
12 proposed resource must be proven. In the past, this was accomplished using estimates
13 derived from the engineering details of a project together with industry literature detailing
14 costs from the actual operations of similar facilities. Estimating the cost of a coal plant or
15 a nuclear plant was a major activity of the engineering divisions of public utilities

²² In Sweeney, D., December 2019, *Morgan Stanley: 'Second Wave of Renewables' to Drive 70 GW of Coal Retirements*, S&P Global Market Intelligence, which states, "Morgan Stanley sees American Electric Power Co. Inc., Dominion Energy Inc., *Southern Co.*, Pinnacle West Capital Corp., PPL Corp. and Duke Energy Corp. as the utilities with the 'largest opportunity' to achieve a valuation rerating under this approach." Available at: https://www.spglobal.com/marketintelligence/en/news-insights/trending/n2V18rq_af4OBgqaW6CmkQ2

In Duquiatan, A., T. Kuykendall, D. Sweeney, and L. Thomas, January 2020, *US Power Generators Set for Another Big Year in Coal Plant Closures in 2020*. S&P Global Market Intelligence, which states, "Low-cost renewables and gas plus cooperative state commissions make the decision to retire coal units – especially those that need capital to comply with environmental regulations – an easy one." Available at: <https://www.spglobal.com/marketintelligence/en/news-insights/trending/1-Ve3d8MnTMmiZGR2Rbshw2>

²³ United States Securities and Exchange Commission, March 21, 2022, *SEC Proposes Rules to Enhance and Standardize Climate-Related Disclosures for Investors*, Press Release. Washington D.C. Available at: <https://www.sec.gov/news/press-release/2022-46>.

The proposed SEC rule (Release Nos. 33-11042; 34-94478; File No. S7-10-22) is available at: <https://www.sec.gov/rules/proposed/2022/33-11042.pdf>.

1 commissions' staff. While this regulatory oversight was important, it did not prevent cost
2 surprises. In the 1980s and 1990s, across the United States there were many examples of
3 cost overruns on (mainly nuclear) power plants, unwarranted excess capacity
4 investments, and a fair amount of public utilities commission activity examining
5 prudence of utility planning of power plants.

6 Recognizing the complexity and deficiencies of regulating generating plant costs, some
7 states were led to adopt competition at the generation level. In such markets, it was no
8 longer important to the regulator what the generator's costs were – the important figure
9 was what price they needed to operate their plant and provide power to the market.
10 Suppliers and newly created markets engaged at various levels: for both long-term
11 capacity, for minute-to-minute energy sales, and for ancillary services. About two-thirds
12 of all U.S. energy sales now comes through such competitive markets.

13 Of course, not all states have moved to wholesale competition: I mentioned previously
14 that Colorado, in addition to Georgia, are two states that continue to operate under a
15 regulatory regime in which utilities continue to build and operate plants while regulators
16 oversee the costs. With the arrival of multiple independent generators and Public Utility
17 Regulatory Policies Act ("PURPA") requirements,²⁴ the regulatory regime evolved
18 further to a different model where the utility went from monopoly provider of energy to a
19 monopsony buyer of capacity and energy from Independent Power Producers ("IPPs"),
20 affiliates of the utility, or from the utility itself. Having multiple suppliers allowed these
21 states to adopt a different form of competition: competitive bidding for contracts to sell

²⁴ See <https://www.law.cornell.edu/uscode/text/16/chapter-46>.

1 power under specified terms. This is the situation in which we now find ourselves in both
2 Georgia and Colorado.

3
4 **Q: WHAT MAKES FOR A SUCCESSFUL COMPETITIVE BIDDING REGIME?**

5 A: Providing useful information for bidders is an essential element in the Colorado planning
6 process. Well informed bidders are more likely to submit bids that represent projects that
7 the utility will want to use, and to provide their best pricing so as to win the competition
8 for a PPA. Creating bidder confidence is an important goal and a welcome outcome.
9 Several additional features in the Colorado model reinforce bidder confidence. Draft
10 RFPs and PPAs are filed up front in the planning process, so they can be scrutinized, and
11 amended and reformed where potential for improvements is found in the hearing process
12 in the planning phase of an IRP. An independent evaluator is selected and employed to
13 facilitate information development and exchange so bidders' questions and concerns can
14 be raised and resolved before RFPs are issued. Bid evaluation scoring criteria are
15 presented in the planning phase, so bidders don't have to guess about how their bids will
16 be scored. All bidder questions are answered, and questions and answers are publicly
17 posted. After bids are submitted, bidders are given opportunities to both revise their bids
18 if found wanting, and to revise them to provide up to date pricing.

19
20 **Q: WHAT ARE THE TRADEOFFS IN PLANNING AND PROCUREMENT?**

21 A: Another recent LBNL analysis provides good examples of how competing outcomes
22 must be balanced to achieve the right formulation for planning and procurement that

1 meets needs in a variety of circumstances.²⁵ The fact that tradeoffs need to be balanced is
2 nothing new in regulation; but it should be kept in mind both when creating a planning
3 and procurement regime and when adjusting it based on experience. Here's how the
4 LBNL report characterizes some important tradeoffs:

- 5
- 6 **a. Regulatory prescriptiveness versus utility flexibility.** More prescriptive rules
7 on how utilities should design and implement competitive solicitations can
8 assuage concerns over utility self-dealing or utilities' incentives to manage costs
9 but may limit utilities' flexibility to find low-cost, low-risk, high-value solutions.
10 More prescriptive requirements on how winning bids are treated can increase
11 developer confidence but may not provide sufficient flexibility to course-correct if
12 issues arise during contracting.
- 13 **b. More versus less transparent process for stakeholders.** Enabling stakeholders
14 to review RFP documents, evaluation methods, and selection results may improve
15 the integrity of the process and increase buy-in for the results but may slow the
16 process and create concerns over the confidentiality of bidders' and utilities'
17 commercially sensitive information.
- 18 **c. More versus less information on evaluation criteria and methods revealed to**
19 **bidders.** Providing more information to bidders on evaluation methods and
20 criteria increases transparency, the likelihood of suitable bids, and fairness but
21 reduces the utility's discretion in evaluating bids and increases the chances that

²⁵ Kahrl, F., March 2021, *All-Source Competitive Solicitations: State and Electricity Utility Practices*, Berkeley, CA: Lawrence Berkeley National Laboratory. pp. 59.

1 bidders will focus on maximizing their scores rather than developing innovative
2 projects.

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

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

16
17 **Q: HOW CAN UTILITY INCENTIVES IMPACT COMPETITIVE ACQUISITION?**

18 **A:** To achieve competitive outcomes in the electric sector, where utilities have near
19 monopolies on sale of electricity, commissions must recognize that this monopoly status
20 also means that utilities are also effectively the only buyers of power as well. Simply put,
21 independent power sellers have nowhere else to go. For this reason, utilities have certain
22 understandable incentives to discriminate against suppliers in favor of their own resource
23 projects, especially when they or their holding company earn a profit on their investment

1 in projects they own. The expression of these incentives can take many forms, including
2 withholding information, unbalanced allocations of risks to suppliers, demands for
3 financial guarantees, liability and indemnification requirements, unfair timeframes for
4 performance, non-disclosure, and confidentiality regimes, as well as vague or unstated
5 evaluation criteria.

6 When a utility's allowed revenues are defined by Cost + Return on Rate Base, the utility
7 has the understandable desire to see its Rate Base grow, because that is the main way it
8 can increase earnings. This incentive creates what is called a "capex bias" inherent in rate
9 base/rate of return regulation. This reliance on rate base growth for earnings growth leads
10 to some challenges for regulators that include:

- 11 1. The Averch-Johnson Effect²⁶ – overuse of capital and underuse of labor;
- 12 2. An "in-house" bias – a preference for utility-owned solutions in contrast to services
13 provided by others, even when lower cost; and
- 14 3. Aversion to embracing DERs and "non-wires alternatives" that are not utility owned.

15 Of course, these considerations have important implications for the design of an effective
16 competitive bidding regime.

²⁶ See, for example, <https://regulationbodyofknowledge.org/glossary/a/averch-johnson-effect-aj-effect/>.

1 **Q: WITH COSTS AND OTHER RESOURCE PROJECT FACTORS CHANGING**
2 **RAPIDLY, HOW CAN REGULATORS AND AN EXTENSIVE PLANNING**
3 **PROCESS COUPLED WITH COMPETITIVE PROCUREMENT KEEP PACE?**

4 A: Timing is a challenge for a competitive resource planning and procurement process that
5 allows full due process rights to intervenors in contested hearings. Bidders face complex
6 business and financing problems to construct their bids and maintain their proposed
7 pricing and other terms during the pendency of a complex regulatory process. Those
8 challenges have to be balanced against the outcomes of a thorough regulatory process,
9 both lots of bids and low prices and resulting portfolio diversity. In Colorado, it has been
10 challenging to maintain strict procedural time limits, as advocates for intervening parties
11 can be creative in their quest for more time to perfect their cases. A Commission policy
12 of “all the due process that’s available in the given time” would help to curtail
13 enthusiasm for extending timeframes. The effect of the timeframe can be partly
14 ameliorated if bidders are given opportunities to both cure bids found to be non-
15 compliant with required terms and to refresh short-listed bids to reflect changing (and
16 usually improving) project economics.

17
18 **Q: WHAT’S THE PATTERN IN COLORADO FOR IMPROVING THE PROCESS?**

19 A: As the process of plan, bid, contract, and build projects has repeated itself on a four-year
20 cycle, Colorado PUC has added another feature to the Colorado model: relentless
21 improvement. In every cycle of which I am aware, as resources are contracted and built,
22 the Colorado PUC has opened a rulemaking docket to improve its planning and
23 procurement rules. The Colorado model isn’t perfect. Every time it happens, the

1 Colorado PUC and parties recognize opportunities to improve it, and that process of
2 relentless improvement continues.

3
4 **Q: WHAT ARE CONSIDERATIONS IN PLANNING PORTFOLIOS TO MANAGE**
5 **FOSSIL GAS PRICE AND AVAILABILITY RISKS?**

6 A: The question is: Gas Price Forecast – Is it better to be wrong too high or wrong too low?
7 Forecasting fossil gas prices in utility planning is both necessary and difficult. A fossil
8 gas price forecast must be made, if gas generation resources are included in planning and
9 procurement, because gas costs can play a key role in determining cost of energy from
10 gas generation options. But forecasting gas prices is notoriously difficult, especially over
11 longer periods. The history of such forecasts shows how often and how much they can be
12 wrong.²⁷ If forecasts for fossil gas prices are likely to be wrong, does it help to consider
13 whether it might be better to be wrong and too high, or wrong and too low? Because risks
14 to consumers are quite different in these two cases, thinking through the implications is
15 worth the effort.²⁸

16 For example, if gas price forecasts are wrong and too high, relatively more efficiency and
17 non-gas resources will be obtained than might be precisely economically efficient.
18 However, more efficiency and more non-gas resources also erect a portfolio hedge
19 against unforeseen gas price spikes. By contrast, if gas price forecasts are wrong and too

²⁷ See, for example, <http://epis.com/powermarketinsights/index.php/2017/05/18/how-good-is-the-eia-at-predicting-henry-hub/> and https://www.researchgate.net/figure/1-EIA-Forecasts-of-Natural-Gas-Price_fig1_237290540.

²⁸ A commonplace response to gas risks is to consider financial hedging. This practice replaces gas price risk with risks of hedge providers' financial positions. Financial hedges don't always provide insurance against risks. For example, the best hedge in the business in 1999 would have resulted in a claim in the Enron bankruptcy in 2001, not money, and not gas. And that claim would have been subordinate to debt holders, who in bankruptcy tend to leave crumbs, not bread, for other claimants.

1 low, risks to consumers who pay gas costs both for their consumption and in their electric
2 rates through fuel cost riders are unhedged – consumers simply have to pay the higher-
3 than-expected costs. So, the risks from a consumer perspective are highly asymmetrical,
4 with more risks attached to being wrong and too low and fewer risks following from
5 being wrong and too high.

6
7 **Q: HOW SHOULD UTILITIES AND THEIR REGULATORS MANAGE THIS**
8 **SITUATION?**

9 A: One good option is to select from the higher options in a rational range of future gas
10 prices, rather than median or low-ball options. Another option is to consider much
11 broader ranges of gas price cost scenarios or sensitivities than are typically modeled in
12 utility resource planning. Winter storm Uri has expanded the possibilities for thinking
13 about fossil gas price spikes. Leaving aside what caused gas prices to spike, whether the
14 situation was entirely anomalous and special to the Electric Reliability Council of Texas
15 (“ERCOT”) and Texas, generally, it is interesting to note that other states that rely on the
16 same sources of gas as Texas were also heavily impacted by the 2021 gas price spike. So,
17 if the lesson for Georgia in terms of adequate planning is that unprecedented events
18 elsewhere can cause price spikes to travel along the gas pipeline system to impact
19 Georgia customers, then planning that encompasses wider ranges of gas price excursions
20 would make sense.

21 In Colorado, during five days of extremely winter weather that impacted both Texas and
22 Colorado in 2021, and when gas demand was high, XcelEnergy reported prices to have
23 moved from about \$3 per MMBTU to \$180, racking up about \$680 million in excess gas

1 costs across its eight states.²⁹ In Colorado, the extra gas costs will cost consumers \$550
2 million across Xcel's gas and electric operations. Several other states were also similarly
3 impacted. Since a price spike – reported to be 200 times above normal over five days –
4 had this kind of impact in this situation, it is not unreasonable to consider modeling
5 significantly higher gas price sensitivities or scenarios or to incorporate the risk of such
6 black swan events.³⁰ Of course, less dramatic effects – like systematically higher gas
7 costs – will also have a deleterious impact on customers and must be anticipated in
8 portfolio modeling.

9
10 **Q: DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?**

11 **A:** Yes.

²⁹ Otarola, M., February 2022, Xcel Energy could Overcharge Customers 'Tens of Millions of Dollars' After Last Year's Cold Snap, State Watchdos Says, CPR News. Available at: <https://www.cpr.org/2022/02/24/xcel-energy-overcharging-customers-cold-weather/>.

³⁰ See the Colorado PUC Response, available at: <https://puc.colorado.gov/uri>.