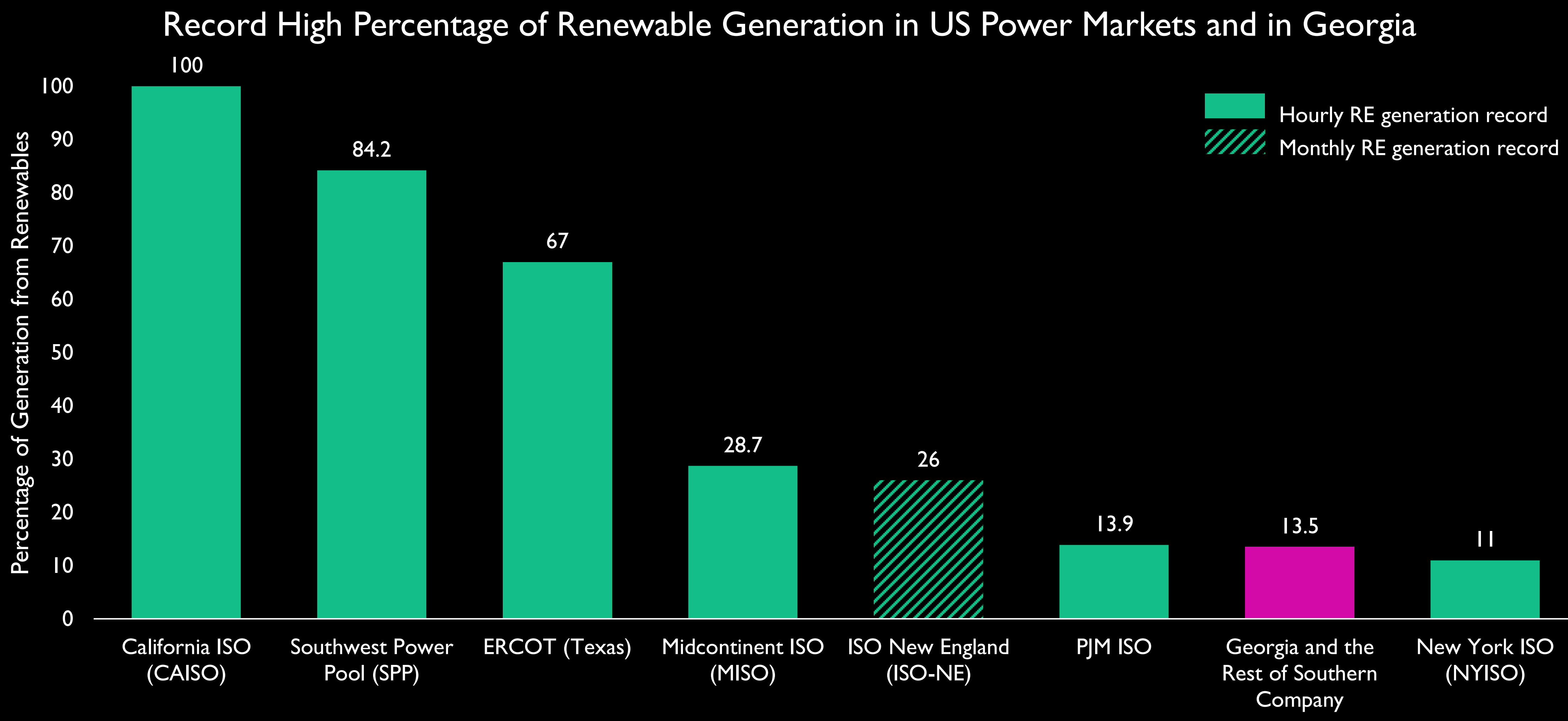
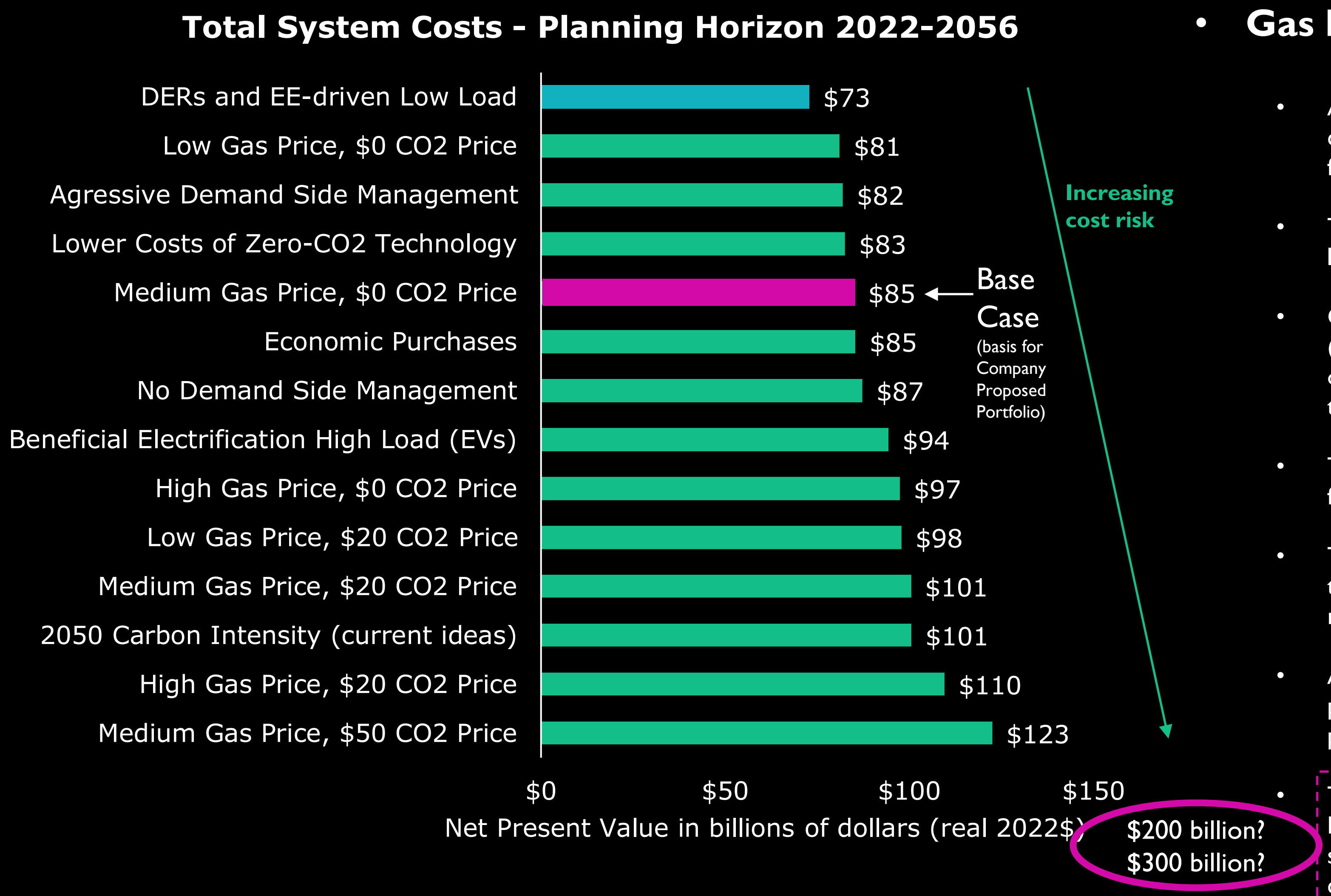
GCES Exhibit 02 – There is no unsolvable technical barrier to more solar on the System



Figures represent hourly peak record for Georgia and rest of SoCo (October 17, 2021, using EIA-930 data), CAISO (April 30, 2022) (<1 hour), SPP (March 29, 2021), ERCOT (April 2022), MISO (December 23, 2020), PJM (March 30, 2020), NYISO (December 6, 2020), and a monthly average for ISO-NE (December 2021)

GCES Exhibit 03 – There is significant cost risk to gas-heavy portfolios like the Base Case

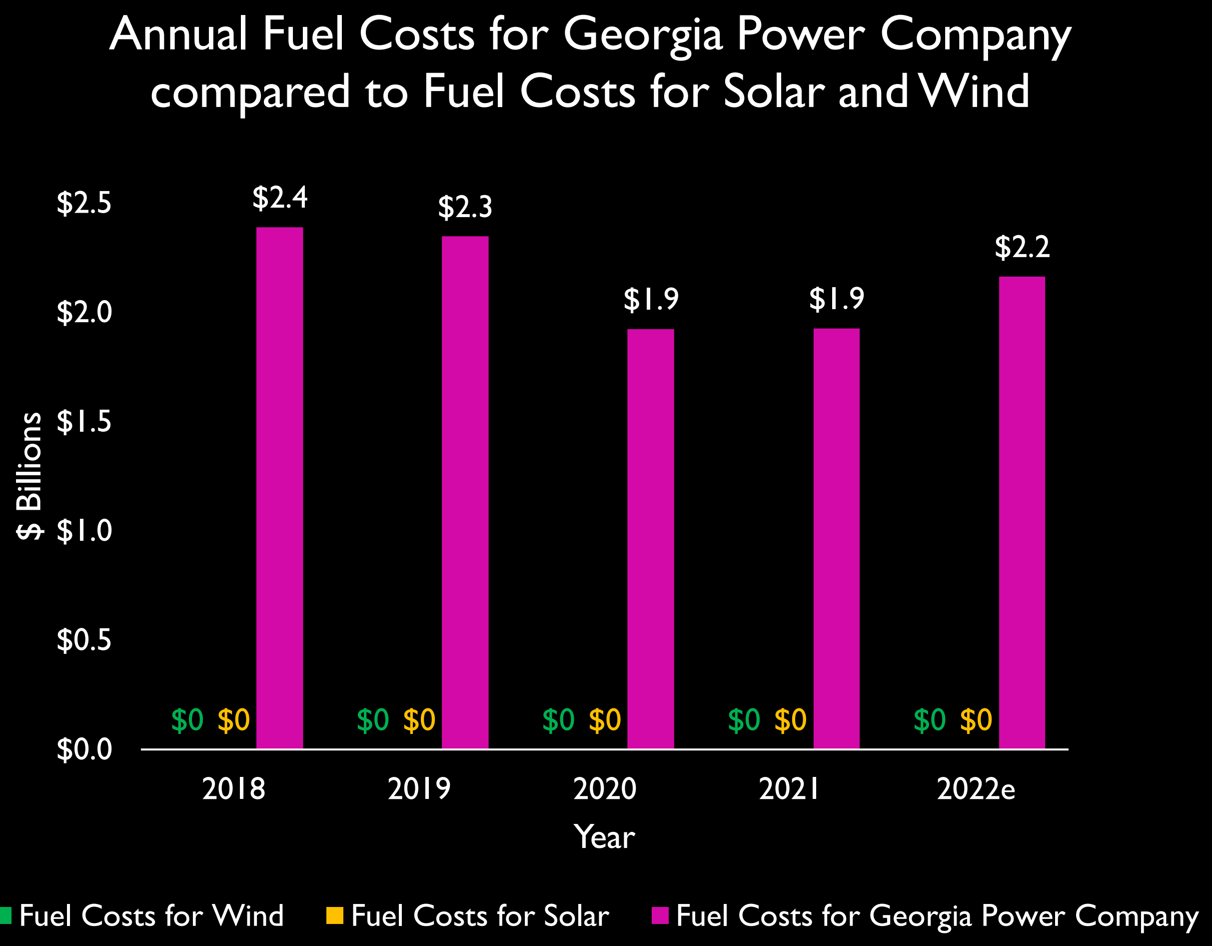


• Gas Price and Carbon Price Risk

- As Georgia Power Company's modeling shows, the costliest portfolios are tied to gas prices and CO_2 prices for carbon
- The scenarios don't have equal costs to meet customer load, and they don't have equal probability of occurring
- Georgia Power Company remains highly dependent on gas (47% of generation and 45% of capacity in 2021), coal, and oil resources, which add multiple significant cost risks to the Base Case
- The Company is seeking to lock-in 2,356 MW of gas PPAs for 10-15 years to add to its extensive gas fleet
- The lower cost portfolio involves DERs, EE, and DSM. Yet the Company is reducing measures on the grounds that recent Avoided Cost is lower
- Avoided Costs fell with Covid (low demand, low gas prices) but we know it has rebounded with recent high gas prices and that is not captured in this 2022 IRP
- There is strong evidence to support the idea that Georgia Power is significantly underestimating the upper total system cost (e.g., $170 CO2 price with true social cost of carbon; upstream methane leakage cost accounting, etc.)

Source: PD Capacity Expansion Plans. This allows us to compare total System costs to meet customer load in today's dollars under each scenario.

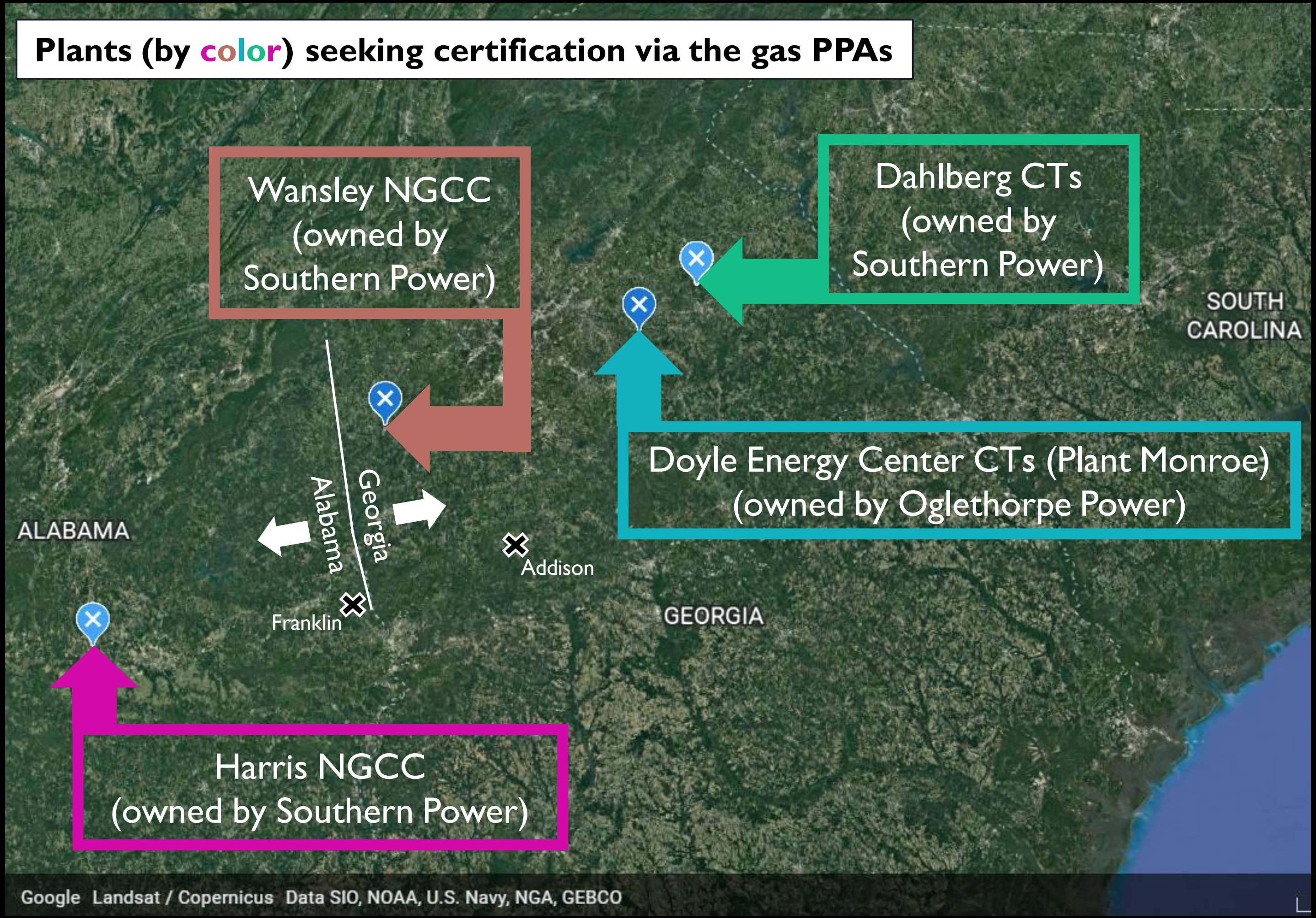
GCES Exhibit 04 – Gas resources incur significant fuel cost and volatility risk that renewable resources do not have at all



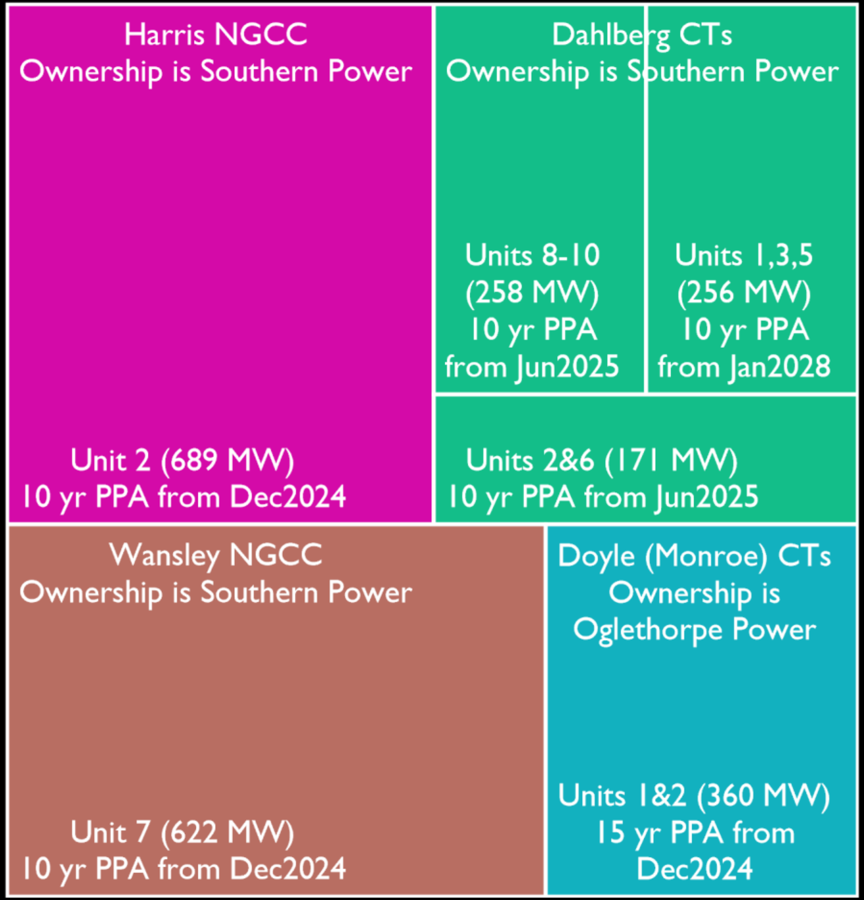
- **Fuel Commodity Price Risk**
  - Georgia Power Company sends $2 billion per year to other states and abroad for fuel costs
  - "*…because we export energy to the rest of the country, we have other people paying our taxes*" – Wyoming official
  - The fuel costs for solar and wind are known with 100% accuracy and for every year into the future

Source: Georgia Power Company monthly fuel cost recovery statements
Source: Former Wyoming Secretary of State Kathy Karpan

GCES Exhibit 05 – 85% of the requested contract capacity, which the 'market' supplied from Alabama and Georgia, is being offered by Southern Power—a Georgia Power Company Affiliate



Power Purchase Agreements — proposed for Certification

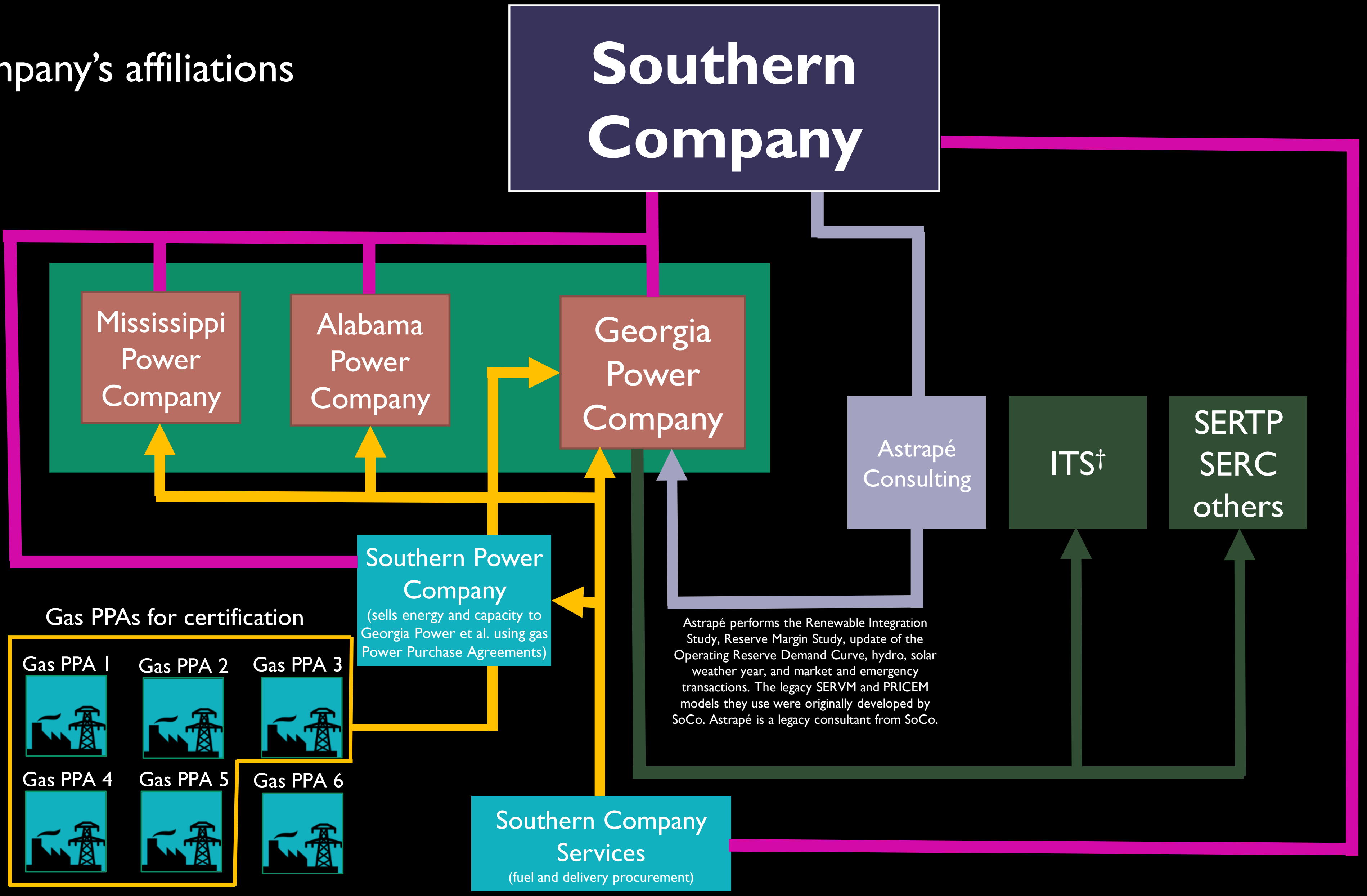


Each box is a PPA with gas plant (color), capacity (size), owner, and tenor.
Total capacity requested by GPC for certification is 2,356 MW, all gas-fired.

See STF-DEA-1-3: Georgia QF #s are very small, just 16 in 2014 (generating 127 GWh) and only 20 in 2021 (generating 43 GWh). QFs do not offer competition

Plant Addison (668 MW) located in GA has a gas PPA contract with Georgia Power. It is owned by Southern Power, who also owns gas Plant Franklin (1,857 MW) in AL

GCES Exhibit 06 –
Georgia Power Company’s affiliations

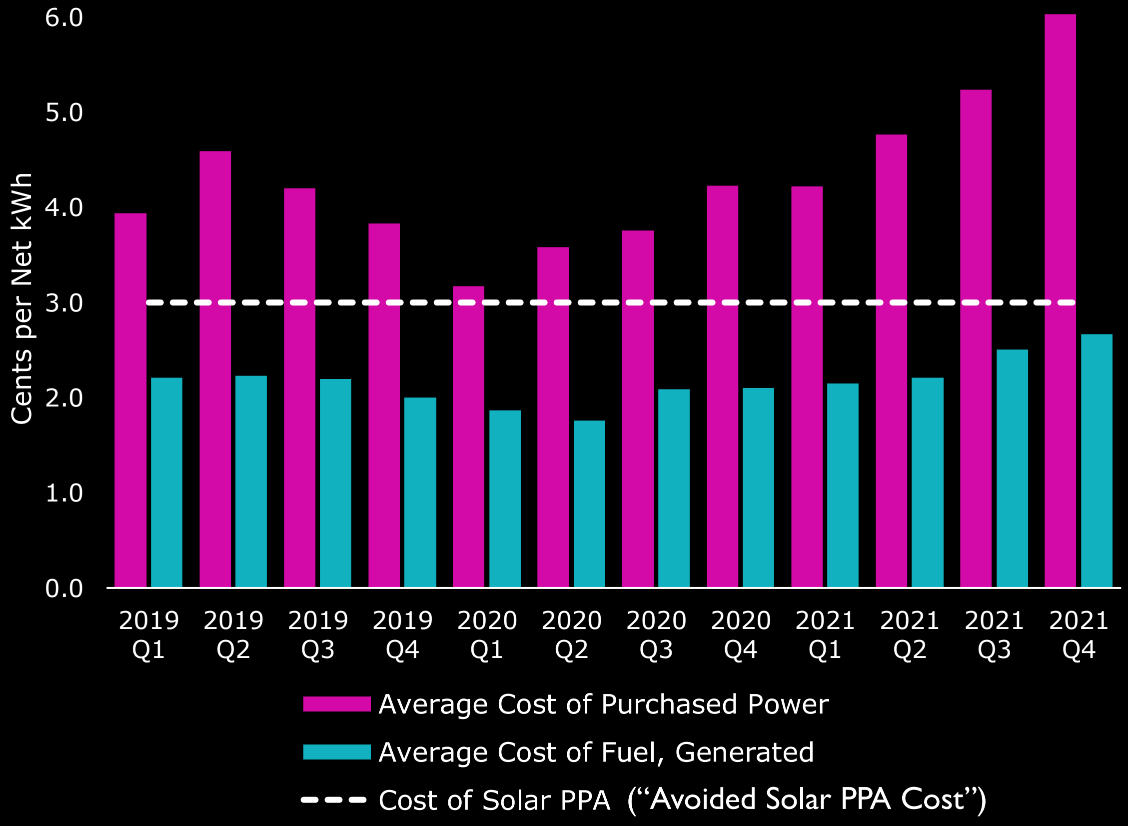


* GPC together with Alabama Power and Mississippi Power operate as a tight electricity pool, aka the System or also SERC-Southeast (SERC-SE) including “merchant” plants like Southern Power Co.
† ITS is the Integrated Transmission System, ownership is shared among GPC, MEAG Power, Georgia Transmission Corporation, and Dalton Utilities
- Not shown: SoCo ownership of Southern Natural Gas Pipeline, Southern Nuclear (Vogtle), Southern Wholesale Energy, or recent divestitures - Sequent EM, Gulf Power Company See more

GCES Exhibit 07 – Purchased Power is Costlier than Solar and GPC-Generated Power

Purchased Power is costly

Georgia Power Company's Cost of Power as reported in SEC 10-Q/K filings
(Generated vs. Purchased Power) (Cents per net kWh)



The Solution

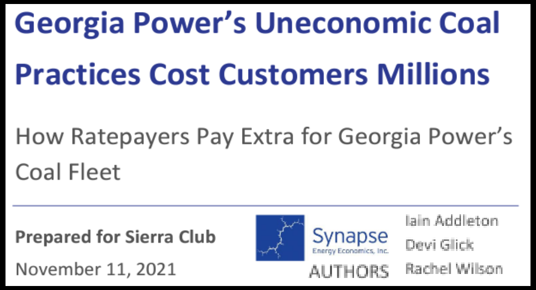
- Reduce the volume of uneconomic purchased power over time and set an “Avoided Solar PPA Cost” equal to average RFP results
- Purchased power is 1.7 to 2.3 times more expensive than power generated by Georgia Power Company
- The Public Service Commission and Georgia Power Company have a longstanding agreement on the Company’s recommendation of a 70 / 30 mix of owned-and-self-generated power vs. purchased power
- Purchased power is not in the economic interests of Georgia or the Company’s customers, including the gas PPAs for which the Company is seeking certification

Source: Southern Company SEC 10-Q/K filings

GCES Exhibit 08 – Uneconomic unit commitment of coal plants

<u>Continued uneconomic dispatch</u>

- Georgia Power Co. regularly operates its coal-fired power plants such that the costs of operating those plants far outweigh the benefits that their customers receive.
- *"From 2017 to 2020, Georgia Power's uneconomic unit-commitment practices resulted in an estimated **<u>$232 million in excess costs</u>** for ratepayers."*
- How does this happen?
  - *Solar, with its $0 or very low variable cost of operation, is almost always called upon to dispatch ahead of more expensive coal-fired generators.*
  - *Coal is expensive to start and stop, so Georgia Power keeps its coal plants running. But the variable cost of the most expensive generator used to meet load sets the price known as "system lambda" which measures how expensive it is to operate the electric grid.*
  - *Georgia Power's coal units often operate at a higher variable cost than the system lambda, which has cost customers at least $232 million over four years from 2017 to 2020.*



Georgia Power's Uneconomic Coal Practices Cost Customers Millions

How Ratepayers Pay Extra for Georgia Power's Coal Fleet

Prepared for Sierra Club
November 11, 2021

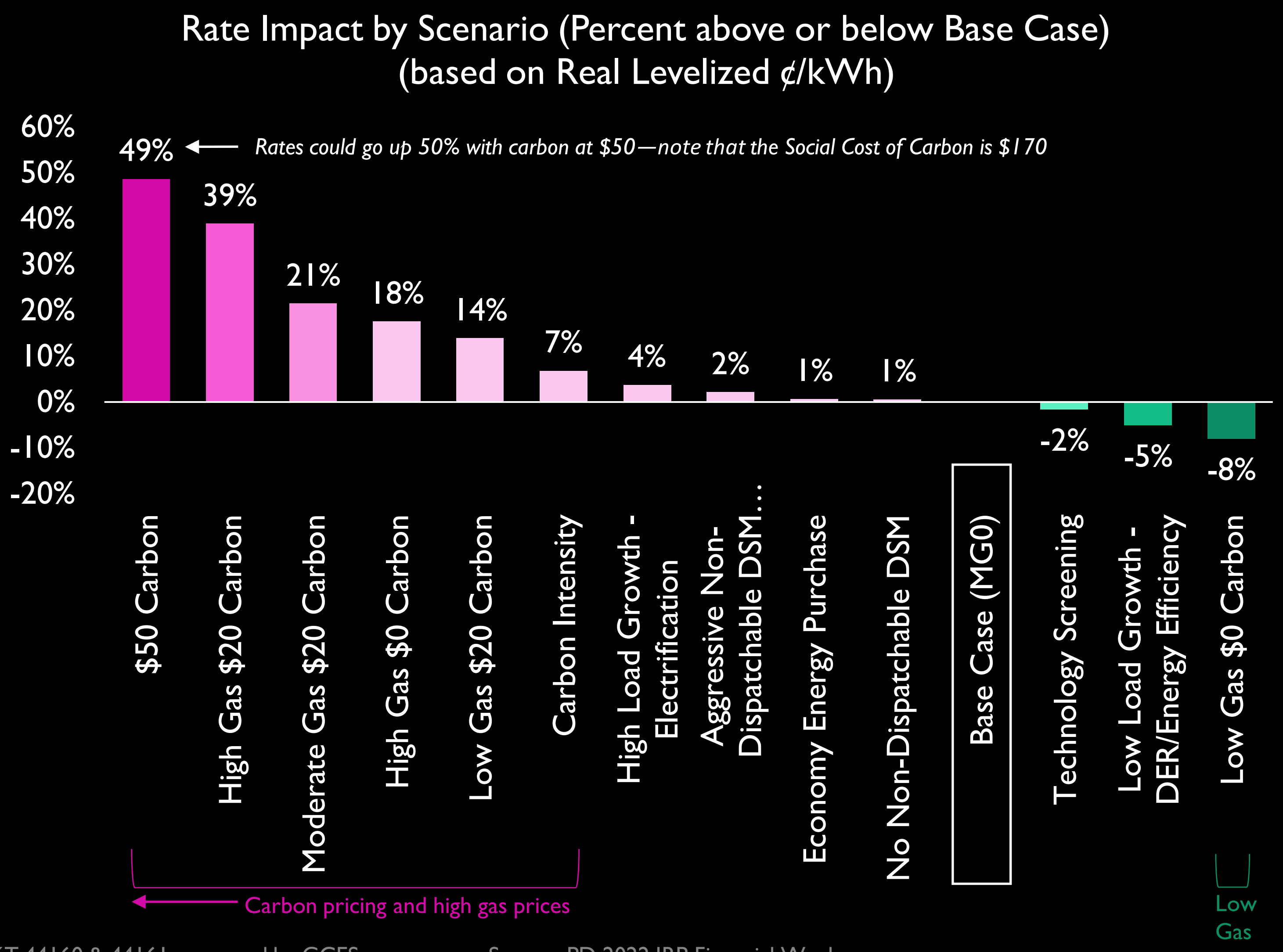
Synapse Energy Economics, Inc.
AUTHORS
Iain Addleton
Devi Glick
Rachel Wilson

<u>The Solution</u>

- **Use One Model:**
  - Use one integrated modeling system that allows supply-side and demand-side options to compete for load, which optimizes dispatch by merit order and lowers System costs
- **Use the Aurora Model:**
  - Specifically, use the Aurora model, which the Company uses now
  - Any technical issue beyond the Company's knowledge goes directly to Energy Exemplar (the licensor of Aurora) for technical support and consulting on things like difficult-to-model EE/DSM programs

Source document: https://www.synapse-energy.com/project/georgia-power-uneconomic-unit-commitment

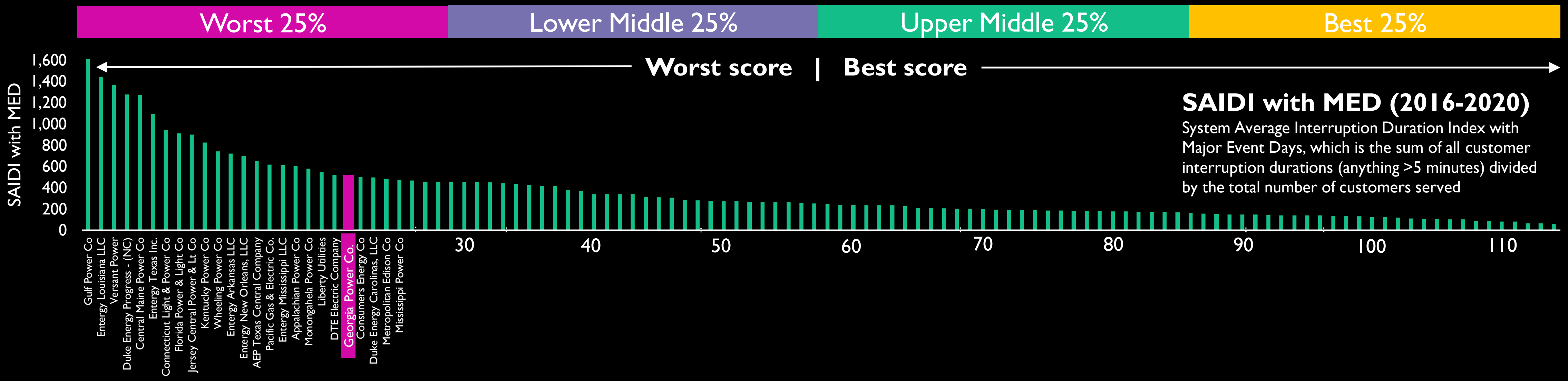
GCES Exhibit 09 – The Rate Impact risk to customers of the Company Base Case is avoidable

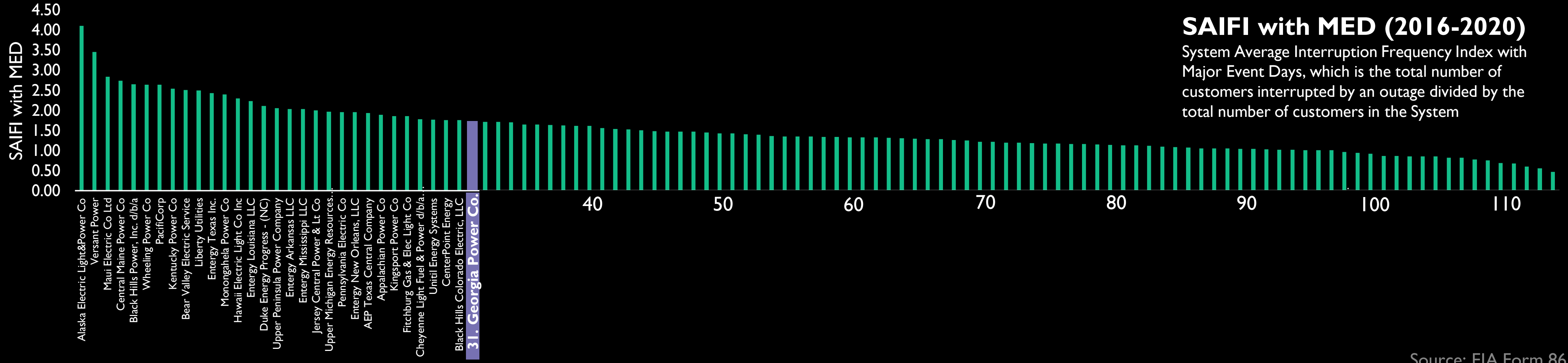


- There is substantial upward rate pressure risk in Georgia Power Company's proposed portfolio from any level of carbon pricing and from high gas prices. It is, in fact, 6x riskier than a low gas future if each scenario is equally likely (which it is not)
- This upward rate pressure risk is avoidable by diversifying away from carbon-emitting, gas-fired generation resources and turning rapidly toward existing zero- and low-carbon technologies (solar, wind), battery storage, EE, DERs, and capacity sharing with neighbors

Source: PD 2022 IRP Financial Workpapers

GCES Exhibit 10 – Georgia Power Co. advertises its ‘Reliability’ and invests significant CAPEX in reliability, but ranks very low among investor utilities for two common reliability metrics 2016-2020



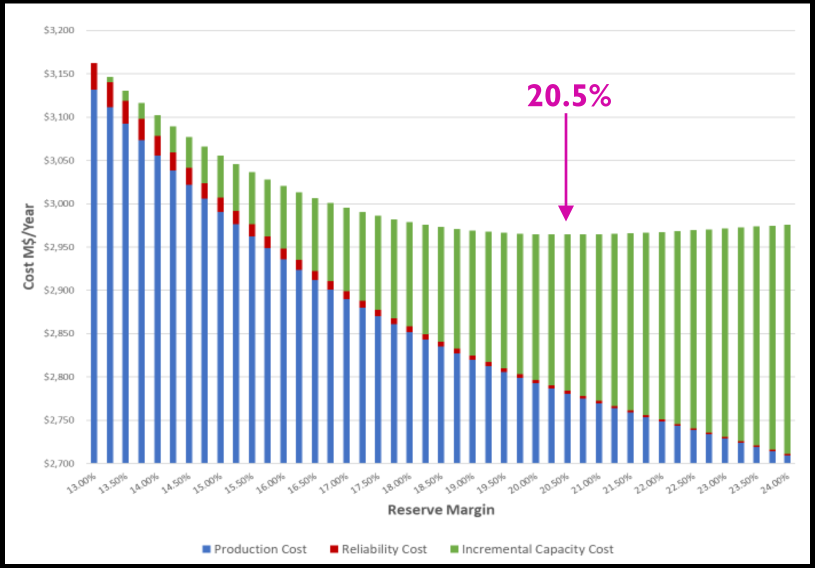


Source: EIA Form 861

GCES Exhibit 11 – The Reserve Margin Study found 20.5% is optimal for summer reserves, but Georgia Power sees a 30.6% reserve margin

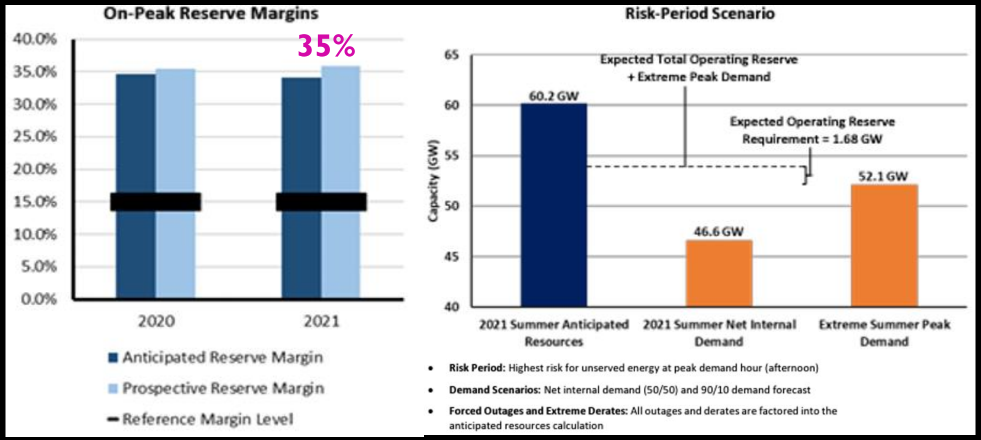
- **Georgia Power Company is overbuilt with capacity**
  - Georgia Power Company's modeling shows that System summer reserve margins are economically optimal at 20.5% (in winter it's 24.25%), slightly less for Georgia Power Company
  - The PD 2022 IRP Summer Summary (MG0) shows early excess capacity, then a 30% Reserve Margin for three years (2025-2027), well over the 20.5% TRM needed for economic Reliability
  - The SERC-Southeast summer reserve margin is even higher at 35% including 'merchant' units
  - This capacity is excessive to Georgia Power Company, putting significant upward pressure on customer rates. In this IRP, Georgia Power has offered 88 MW of wholesale capacity to the retail jurisdiction to reduce excess capacity, which would reduce the reserve margin by 0.4%

Georgia Power Company Economic Summer Target Reserve Margin



2022 IRP Summer Reserve Margins (MG0 Scenario)
excludes generic expansion resources

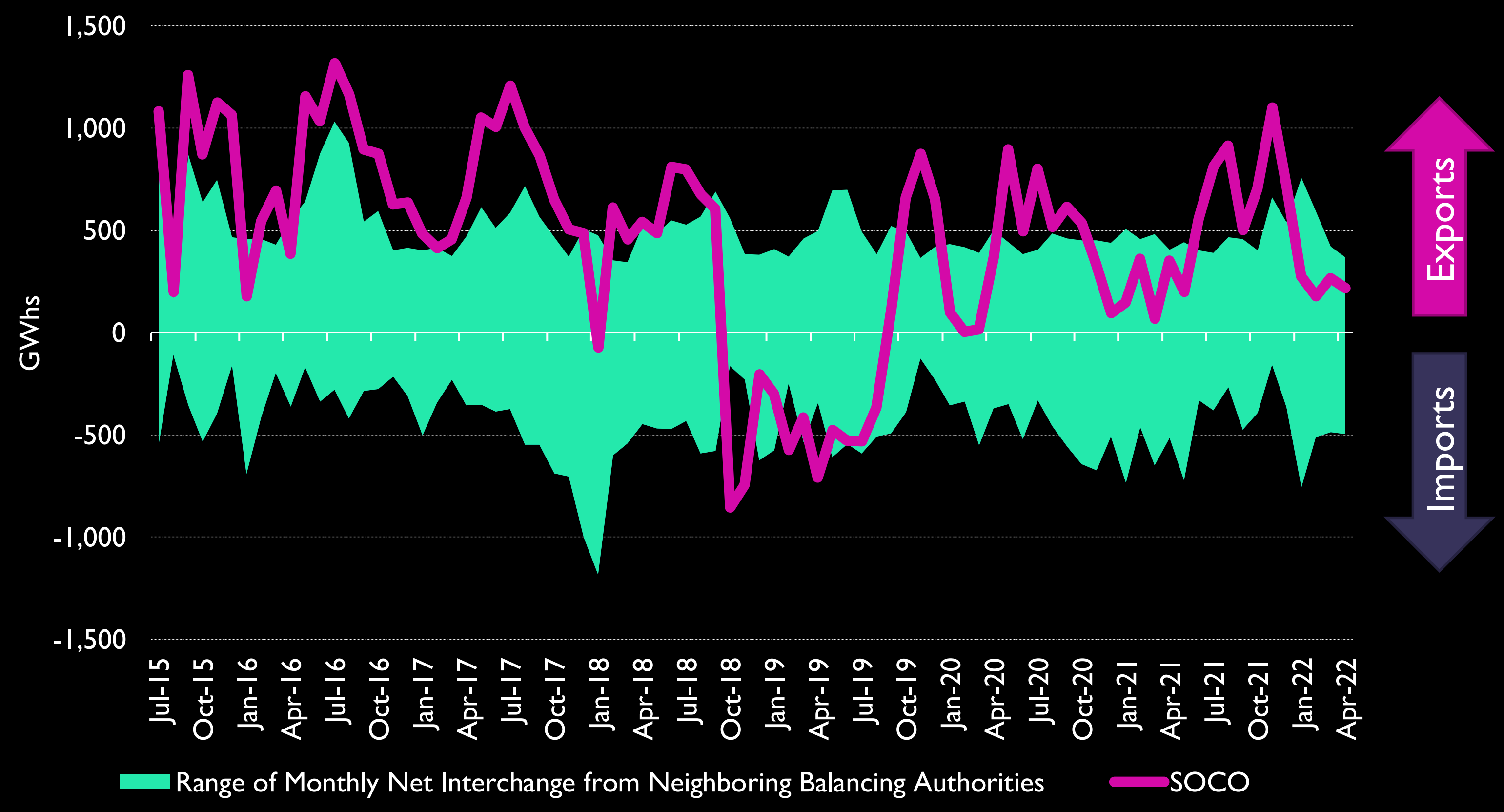
NERC Summer 2021 Reliability Assessment for SERC-Southeast



Source: 2022 IRP Reserve Margin Study and www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf

GCES Exhibit 12 – Georgia Power exports energy because of significant surplus capacity

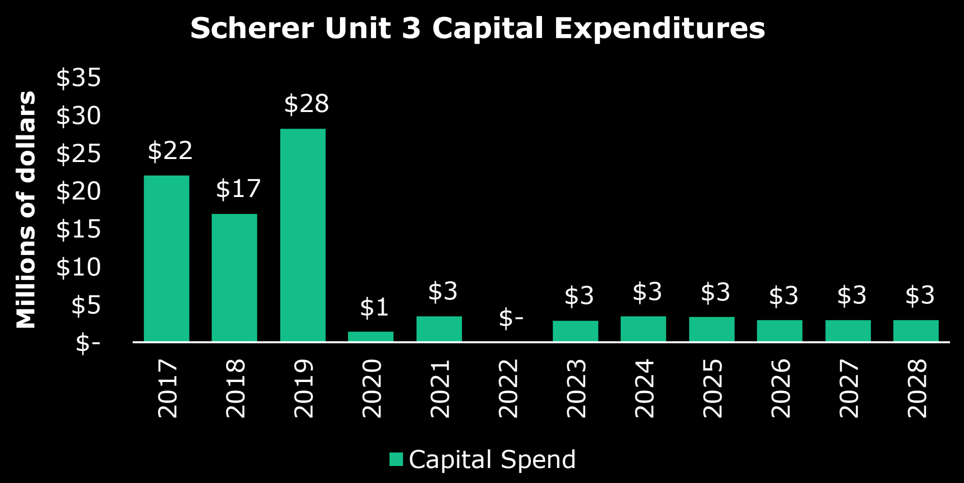
- From July 2015 to April 22, Georgia Power Company & OpCos exported 37.5 TWhs of surplus energy, a monthly average of 458 GWh
- This level of exports is a strong signal that Georgia Power Company and the OpCos: (a) have too much capacity, (b) are operating units out of economic dispatch, or (c) both

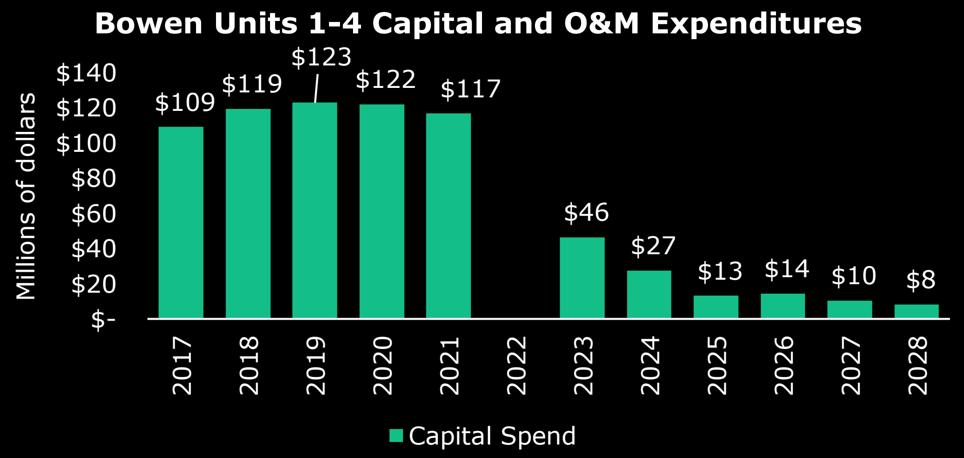


Utility Balancing Authority	Average Monthly Interchange (GWh)	Capacity (GW)
Southern Company (SOCO)	**458**	**43**
Dominion Energy South Carolina	354	6
SC Public Service Authority	320	6
Florida Power and Light	295	28
MISO South (Z8-10)	262	36
Duke Energy Florida	128	11
City of Tallahassee	74	1
PowerSouth Energy Cooperative	-21	2
Southeastern Power Administration	-160	1
Duke Energy Carolinas	-257	20
Tennessee Valley Authority (TVA)	-390	38

Sources: EIA Form 930 and company reports

GCES Exhibit 13 – Remaining coal units will see underfunded capital investments, which will add to Reliability risks

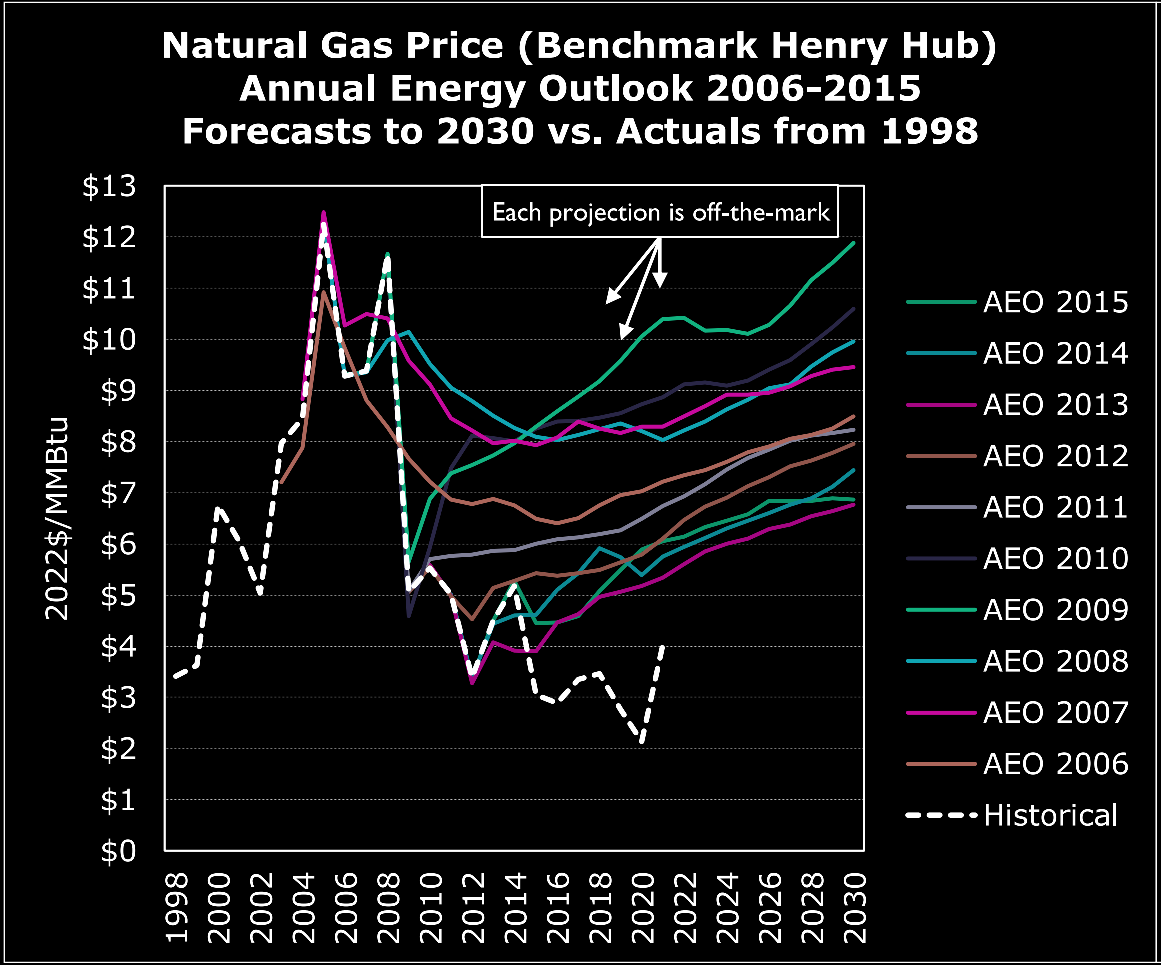


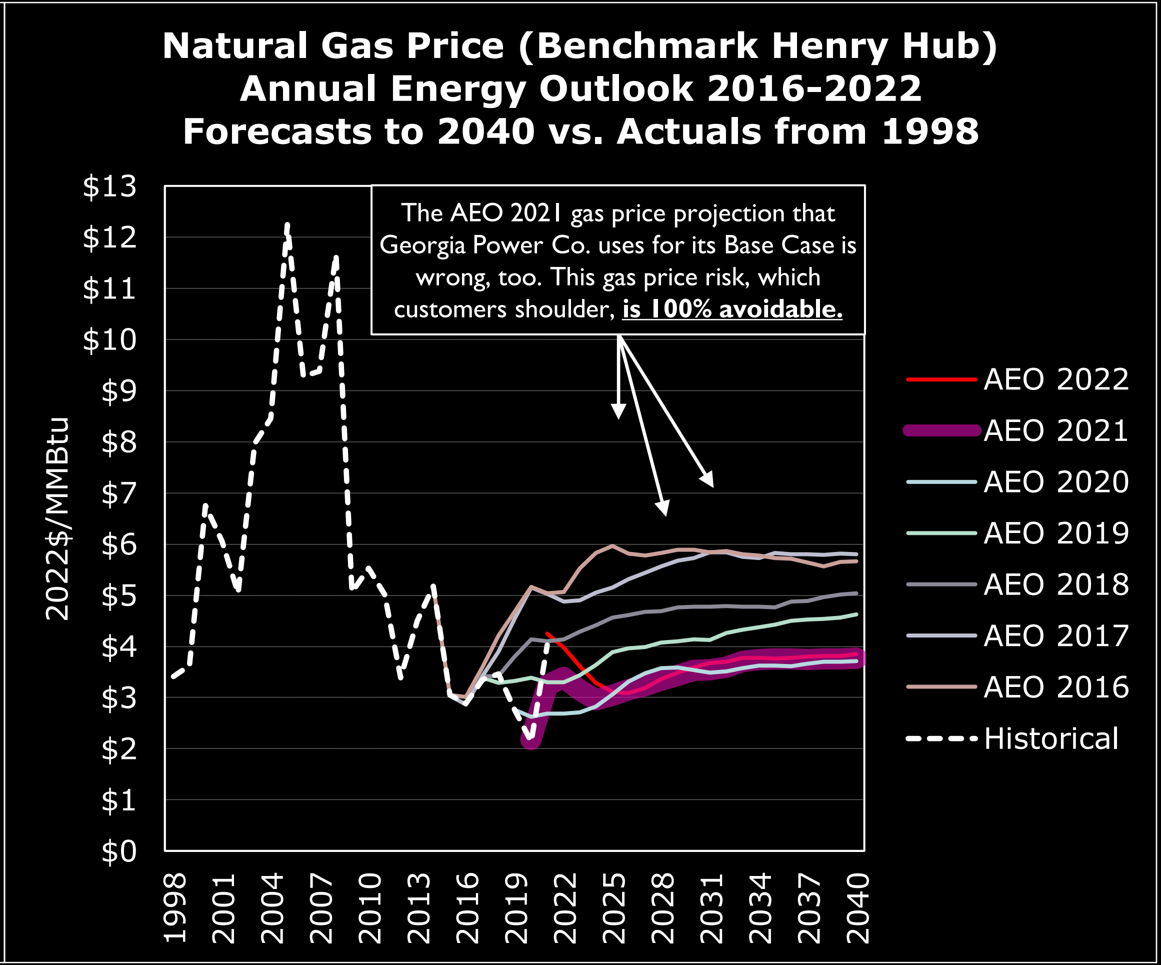


- "The Company will continue to invest in the reliable operation of Plant Bowen Units 3-4, which are critical to preserving reliability and resiliency in north Georgia and cannot be retired at this time without jeopardizing System reliability."
- On Commission order, there is a very large reduction in capital and operations and maintenance spend at the Company's legacy coal units, including Bowen Units 3-4, which will negatively impact System reliability

Sources: 2022 IRP 1-5, PD STF-PIA-23-1, PD STF-PIA-23-5 for 2017-2021, and Company responses to Staff requests on the same DRs

GCES Exhibit 14 – Georgia Power Company faces significant uncertainty around future gas prices, and cannot rely on the AEO forecast



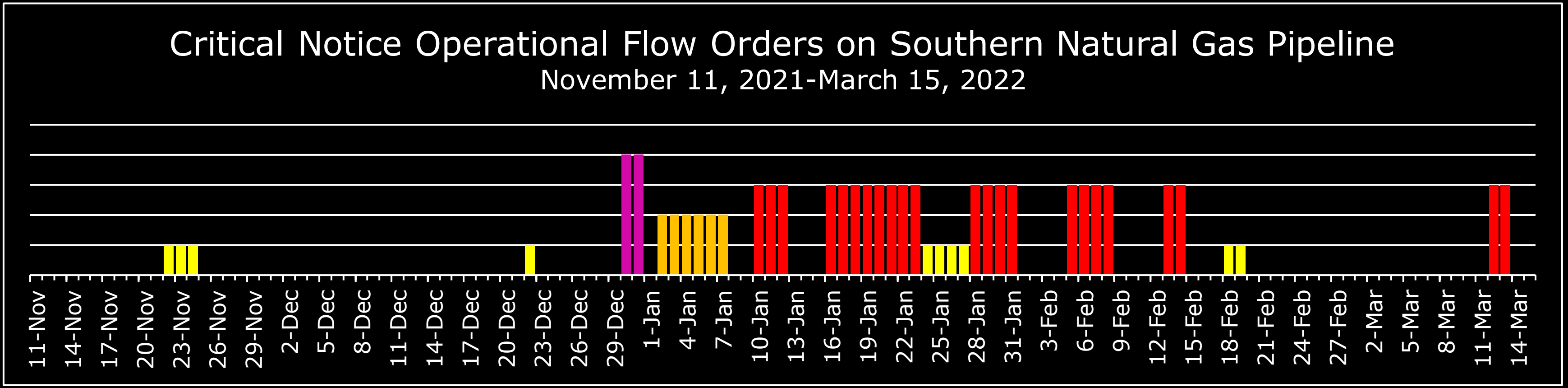


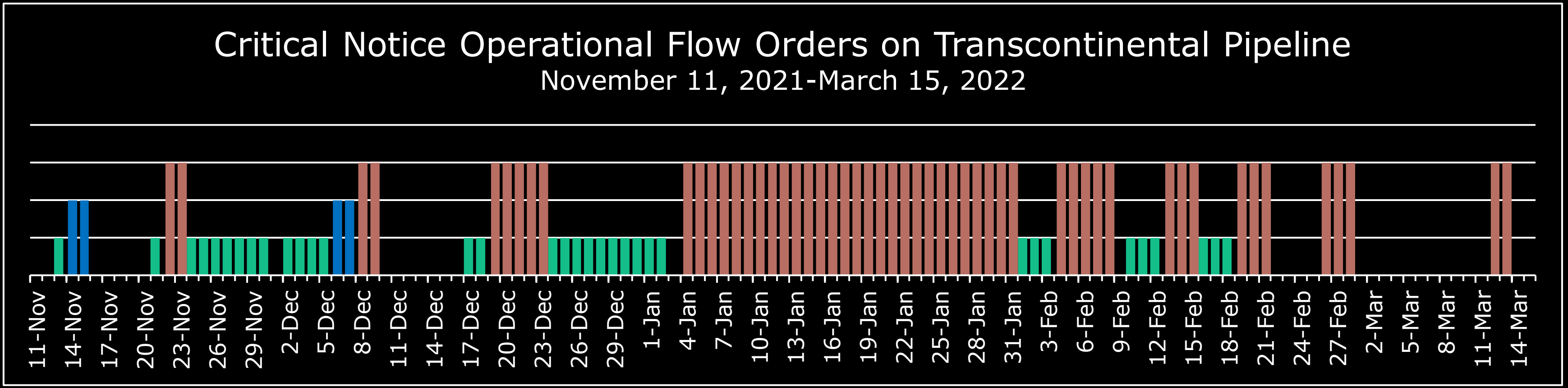
Source: US Energy Information Administration

GCES Exhibit 15 – Only two gas pipelines serve Georgia Power and often see constraints

Georgia Power: "As the Company continues to evolve its generation fleet toward a larger share of resources that either have no on-site fuel storage or are intermittent, there is increased fuel transportation risk associated with providing reliable electric service to customers." (IRP 18-133)

- Open question: Given GPC's reliance on marketed gas, including some with interruptible transportation, and limited dual fuel backup, how have OFOs impacted the gas fleet's economic operations and fuel costs?





Magenta	Type 6 for Longs (imbalances threaten system integrity)
Red	Type 3 Level 2 (200 Dekatherm tolerance, higher penalty)
Orange	Type 3 Level 2 (500 Dekatherm tolerance, standard penalty)
Yellow	Type 3 Level 1 (daily market demand exceeds capacity)

Brown	Zone 4 Operational Flow Order (covering Georgia, Alabama, Mississippi), limited to most restrictive 5% tolerance band
Blue	Zone 4 Operational Flow Order (covering Georgia, Alabama, Mississippi), limited to an 8% tolerance band
Green	Zone 4 Operational Flow Order (covering Georgia, Alabama, Mississippi), limited to a 10% tolerance band

Source: Williams Co. for Transcontinental; and Kinder Morgan for Southern Natural Pipeline. Note: Southern Company is 50% owner of SoNat Pipeline

GCES Exhibit 16 – Solar+Storage is Cheaper and more Reliable than Gas CTs

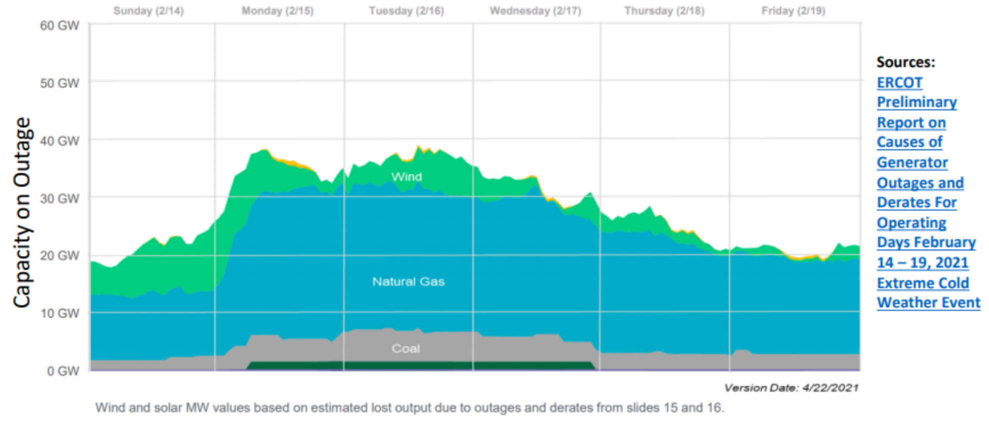
Solar+Storage, comparison

- Solar+Storage Levelized Cost of Energy: **$85-$158/MWh***
- Table IV-1: ELCC Study Results (Georgia Power modeling), together with GCES estimates, show that solar+storage is equal or better than gas CT in terms of ELCC (or ICE factor) and Reliability

GPC ELCC	Winter			Non-Winter		
Technology	0.5GW	1GW	3GW	0.5GW	1GW	3GW
Solar Tracking ELCC	10%	5%	5%	35%	30%	25%
Battery 4hr ELCC	90%	90%	95%	100%	100%	70%
Wind ELCC	50%	50%	50%	40%	40%	40%
GCES						
Solar+Storage† ELCC	95%	92%	91%	97%	96%	94%
Gas CT availability	96.7%	96.7%	96.7%	96.7%	96.7%	96.7%
Gas CT† ELCC	91%	91%	90%	93%	93%	92%

Gas-Fired Combustion Turbine

- Gas CT Levelized Cost of Energy: $141-$204/MWh*
- Gas CT Availability (100%–EFOR): 96.7% (actual is likely 90%–93%)
- Gas CTs were very energy-limited in Texas February 2021 (see below)
- ***As gas-fired capacity saturates a portfolio, gas ELCC decreases too***



Wind and solar MW values based on estimated lost output due to outages and derates from slides 15 and 16.

+ Highly correlated outages, especially in extreme cold snaps
+ Ambient derates during extreme temperatures
+ Fuel supply risk and gas sector dependency

= Need to apply ELCC to other resource types to pick up on peak winter risk

- The above comparison is based on LCOE, ELCC, and Availability. But another comparison is simply to look at Real-Time System Pricing: At any point—now or later—compare current hourly pricing on the Southern Company System (which is Georgia Power Company's pricing) to the cost of the large solar PPAs awarded at just over $30/MWh.

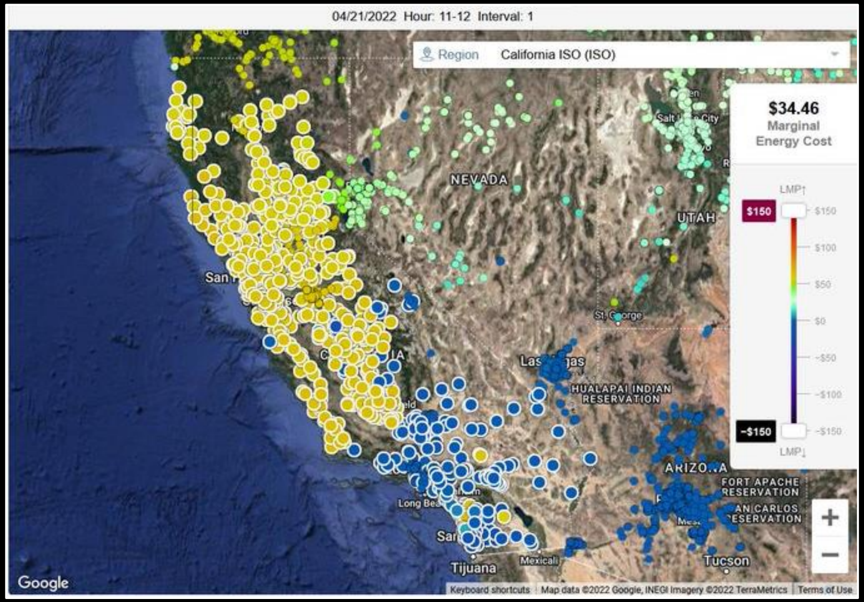
* See Lazard 2021 LCOE p.4 and Lazard 2021 LCOS p. 6 Lazard LCOE and LCOS

† GCES view of ICE factor

GCES Exhibit 17 – Specific state situations brought up in 2022 IRP hearings

• California Paying to Curtail Solar

- In California as elsewhere, solar's value to a grid is to replace costlier generation
- With 35 GW of solar capacity in CAISO, on both sides of the meter, this is significantly reducing marginal costs during the daytime (and total system cost)
- Transmission constraints are impacting prices and forcing solar curtailments. For example, on April 21, 2022, a transmission constraint on Path 26 contributed to an average price across the state of $34.46/MWh, to a price in the Bay Area >$60/MWh, and to a price in the south of -$15/MWh (payment to not generate).
- Georgia is years from this problem. Georgia has 1/8 the solar capacity and 1/4 the population of California. Careful planning and market reform can mitigate this risk



• Florida Net Metering Legislation

- In hearings, the Commission stated, "*You know the state of Florida, just through their legislature, rolled back net monthly netting*"
- On April 27, 2022, Governor DeSantis vetoed CS/CS/HB 741 Net Metering bill, which authorized public utilities to impose an Additional Sum to recover lost revenues resulting from residential solar generation that exceeds the public utility's estimate
- DeSantis: "*The amount that may be recovered under this provision is speculative and would be borne by all customers.*"

- In hearings, GPC estimated that Florida has "*something like $700 million in cost shifting*" and stated "*…we see places like Florida with really big penetrations of customers and decide that this is now such a large amount we've got to undo this. That just doesn't make any sense…*" and "*Even though the amounts are small now, it's my testimony that it's absolutely inappropriate to design a program or to grow a program that creates cost shift even as small as the first kilowatt hour.*"

Sources: CAISO, 2022 IRP hearings and www.flgov.com/2022/04/27/governor-ron-desantis-signs-ten-bills-and-vetoes-one-bill