Modeling Update

SOUTH CAROLINA ELECTRICITY MARKET REFORM MEASURES ADVISORY BOARD

PRESENTED BY

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9/26/2022

Brattle

Agenda

1. Objectives
2. Model Description and Inputs
3. Initial Calibration Findings
4. Next Steps

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1. **Objectives**
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Objectives for this Meeting

- **Describe off-the-shelf model inputs and update made from public data**
- **Present initial model calibration results**

Overview of Modeling Approach

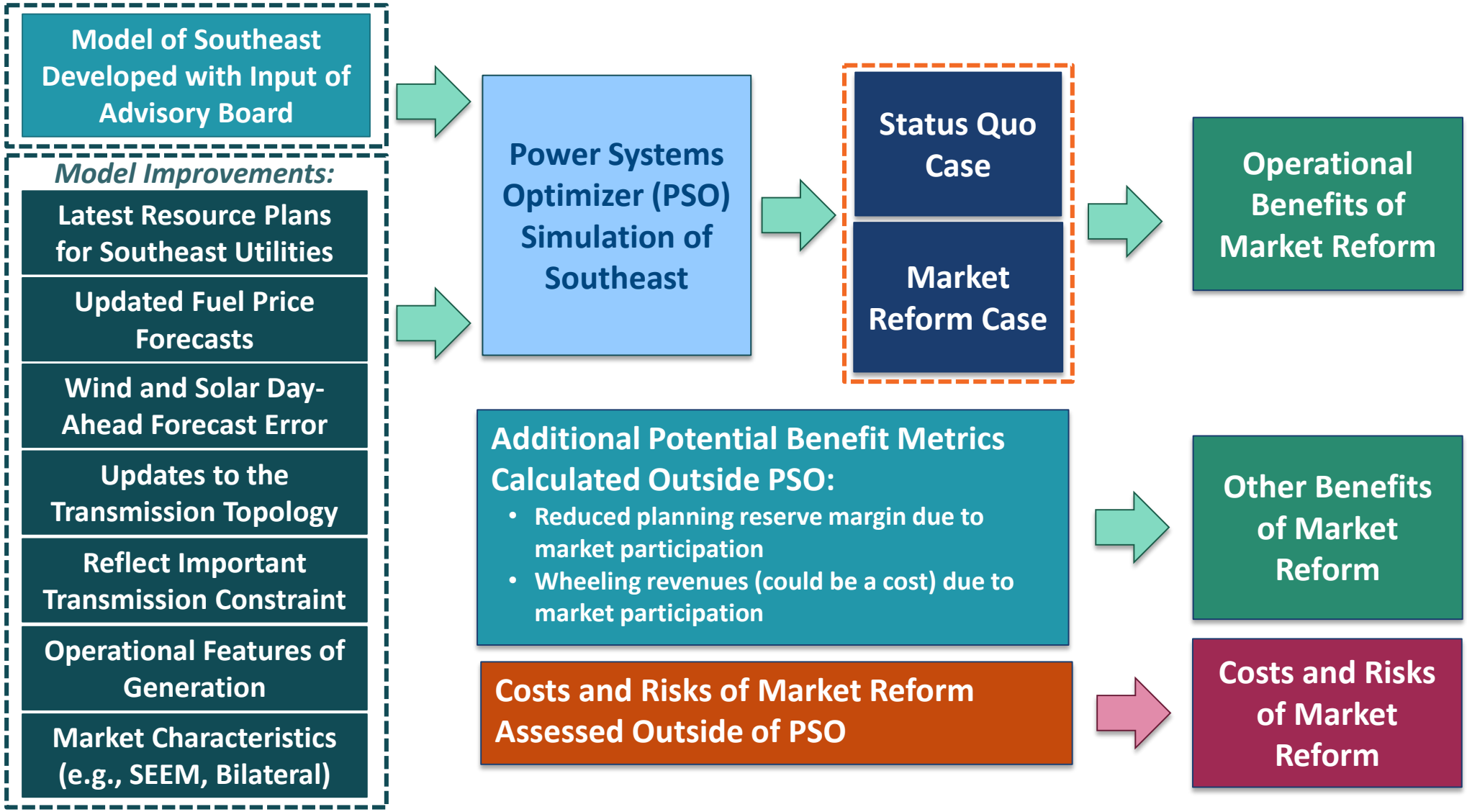
We are running a production cost simulation of the Southeast and PJM to assess operational benefits of market reforms

We use an advanced model called Power System Optimizer (PSO)

- Deep relationship with Enelytix, the developer
- Nodal model representing each load and generator bus in the Southeast
- Captures day-ahead forecasting uncertainty for load and renewable resources
- Detailed operating reserve and ancillary service product definition
- Using a pre-populated model of the Southeast region provided by Enelytix
- We are continuing to update modeling assumptions to reflect the most recent utility resource plans and forecasts of system conditions and costs

Uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs

Study Framework and Benefits Calculation



Simulated Market Reform Options

We are planning to simulate four different market reform options that represent part of the spectrum of possible reform options

Market Reform Options

- **Joint Dispatch Agreement in the Carolinas**
- **Energy Imbalance Market in the Southeast**
- **Southeast RTO (w/ Vertically Integrated Utility)**
- **Carolinas in PJM RTO (w/ Vertically Integrated Utility**

The analysis will need to start with an assessment of the Status Quo, including the SEEM

- To study the SEEM we would develop a model of the power system in the entire Southeast
- We would simulate one scenario for each option and compare against the Status Quo
- We plan study 2030
- We will ask the Advisory Board to provide data and information

Modeling Steps

Step 1 – Benchmark and Calibrate the Model (In Progress)
- Simulate the Southeast using 2020 inputs to verify system dynamics
- Ensure that SEEM member entities and PJM are correctly represented

Step 2 – Create 2030 Status Quo Case (In Progress)
- Model SEEM market
- Update inputs to forecasted 2030 values
- Get input from the Advisory Board

Step 3 – Test Market Reform Options
- Model study market constructs
- Compare benefit metrics against status quo case

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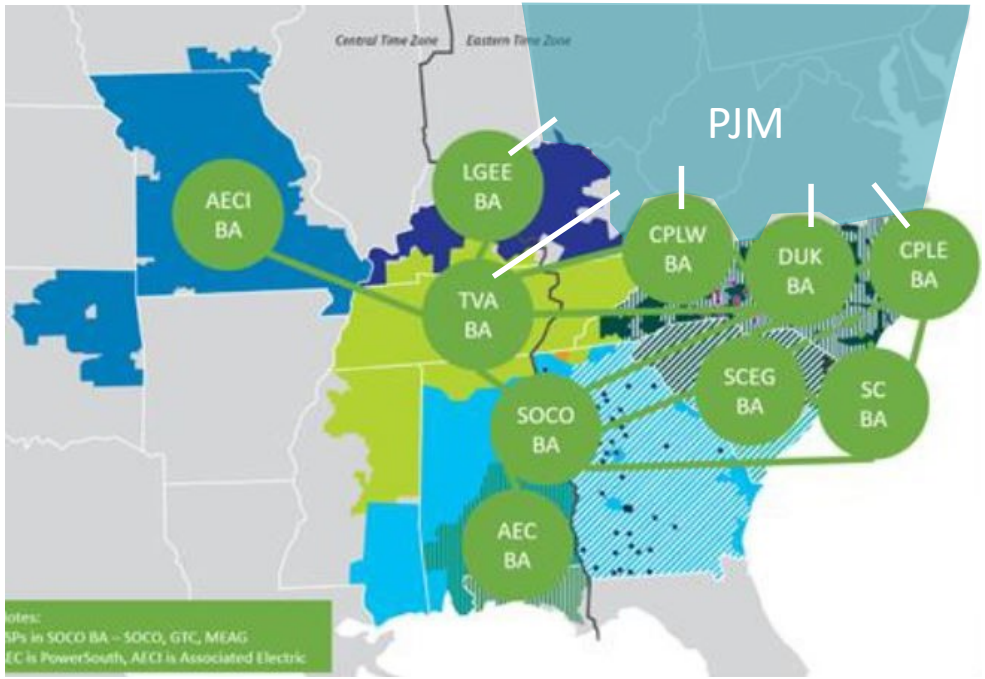
Model Footprint

We model the Carolinas, the SEEM balancing authorities, and all of PJM

- Carolinas are modeled as Duke Carolinas and Duke Progress, Santee Cooper, South Carolina Electric & Gas
- Other BAs in the SEEM footprint include:
  - Southern Company (Georgia Power, Mississippi, Alabama and non-SOCO operating companies like Oglethorpe)
  - TVA
  - Power South Florida (AEC), Louisville Gas and Electric (LGEE), and Associated Electric Cooperative (AECI)
- Trading with external areas (FL, NYISO, and MISO) is represented as fixed interchanges



PSO Simulates Grid Operator Decision-Making

PSO modeling cycles built to replicate real-world operations

1+ Days Prior	Hours/Day Prior	15 Minutes Prior	5-60 Minutes Prior
Unit Commitment	**Day-Ahead Market and Bilateral Trading**	**SEEM Trading**	**Real-Time Dispatch**
– System operators commit resources on a utility-specific basis – Allows sufficient advance notice for units with long startup times	– RTOs (PJM) clear day-ahead market bids – Bilateral spot trades carried out in the non-RTO areas of the model (e.g., Southeast)	– SEEM trades take place as 15-minute transactions scheduled 15 minutes in advance	– Final dispatch adjustments conducted at utility-specific basis – In EIM Case, real-time optimization of dispatch subject to transmission constraints takes place

Demand Forecasts

Default forecasted peak load and and total demand sourced from FERC Form 714 data, filed by balancing area authorities.

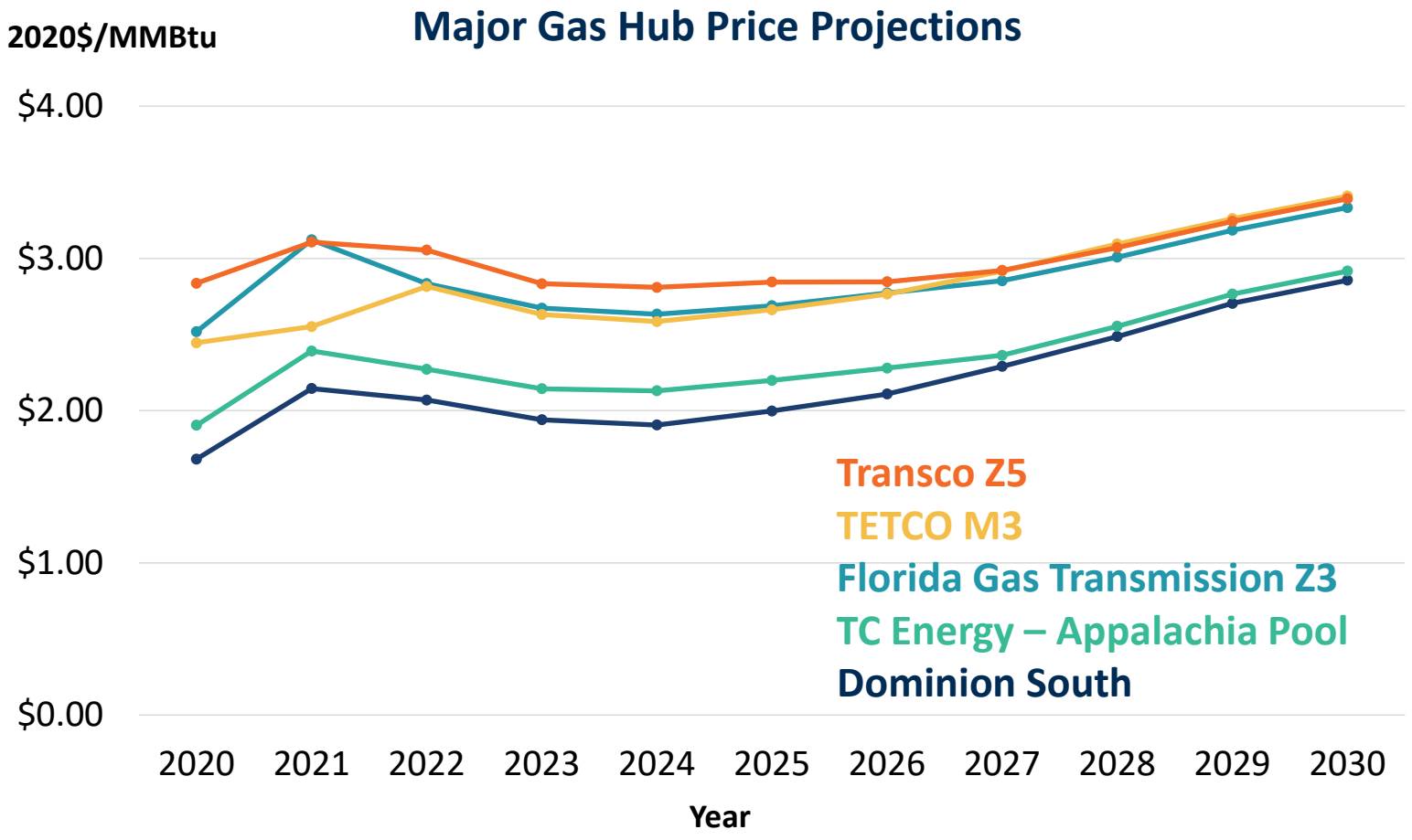
Utility/RTO	2020 Load (GWh)	2020 Peak Load (MW)	2030 Load (GWh)	2030 Peak Load (MW)
Duke Carolinas (DUKE)	101,239	18,709	116,430	21,684
Duke Progress (CPL)	64,656	14,732	65,767	14,717
Santee Cooper (SC)	22,753	4,553	25,055	5,177
South Carolina Electric & Gas (SCEG)	25,676	5,248	24,682	5,209
PJM	778,633	150,134	820,854	158,275
TVA	153,969	28,751	-	-
SOCO	222,592	42,907	233,331	44,056
Louisville (LGEE)	32,157	6,028	37,300	6,940
AECI	22,996	5,202	21,680	4,891

Carolina BAAs will have an opportunity to update their load forecasts based on most recent data

Natural Gas Price Projections

Projections were developed by Enelytix using near-term forward curves and long-term forecasts from the EIA Annual Energy Outlook.

- 2020 gas prices used for benchmarking are historical prices, accessed on S&P Global
- Generation owners in Carolinas footprint will be able to provide unit-specific delivery charges



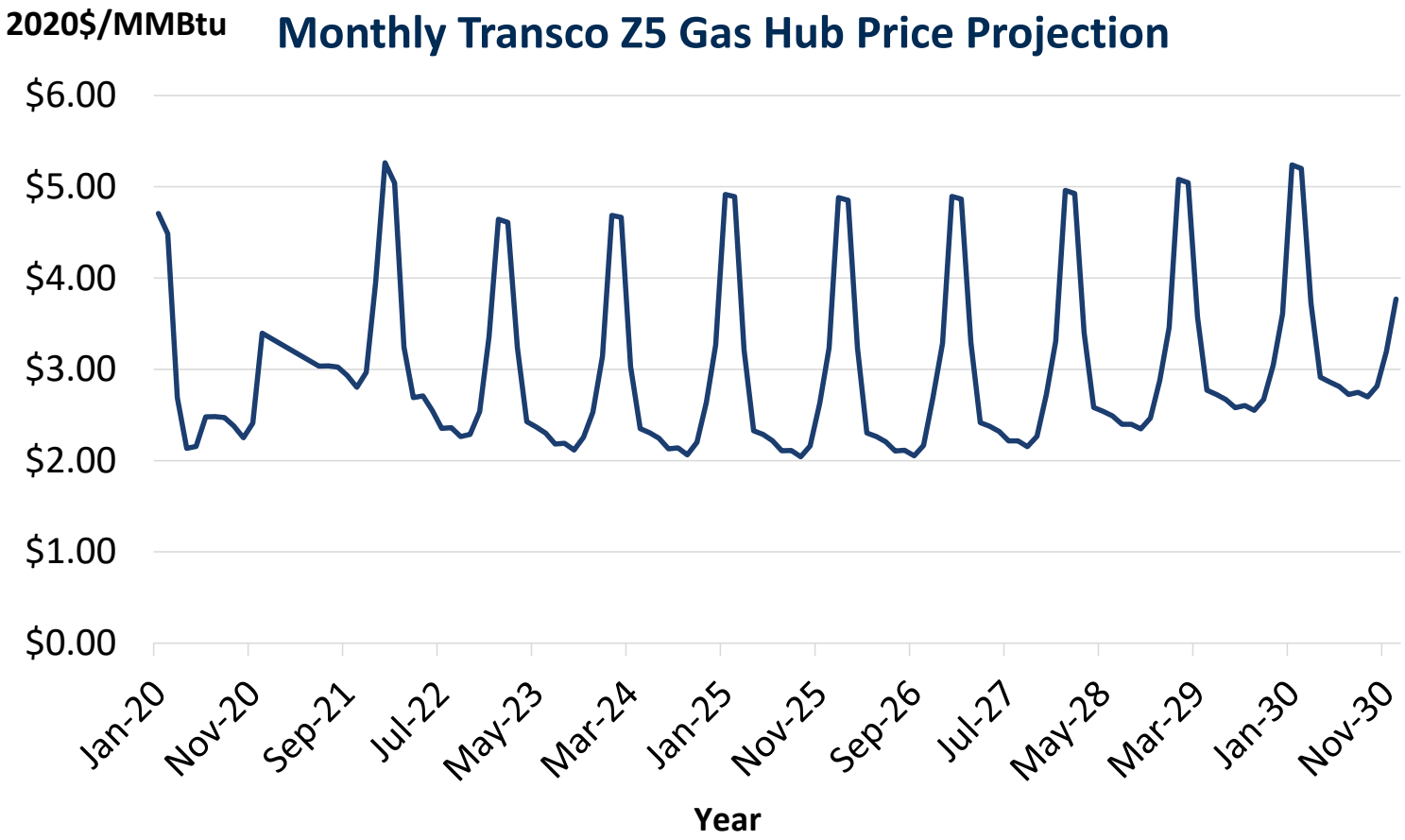
Monthly Natural Gas Price Trends

Model uses daily gas prices

- We apply plant-level delivery adders based on supplier type and plant type.
- Generation owners in Carolinas footprint will be able to provide unit-specific delivery charges

Natural Gas Delivery Adders
($/MMBtu)

	Connected to Pipeline	Served by Local Distribution Company
Baseload	$0.05	$0.20
Peaking	$0.15	$0.40



Other Fuel Prices

Fuel oil prices are based on historical spot prices as of March 18, 2021, projected using EIA AEO 2021 trends

Uranium prices are assumed to be a fixed $0.99/MMBtu (nominal)

- Using calculator from the Bulletin of the Atomic Scientists

Plant-level coal prices are based on S&P Global power plant operations database

- Annual price of coal delivered ($/ton) divided by average heat content (Btu/lbs)
- Projections based on EIA AEO

Physical Transmission Topology

The model represents the physical transmission topology based on the Multiregional Modeling Working Group (MMWG) 2018 power flow case for summer peak 2020

- All network resources and generation is mapped to bus bars
- All bus bars are mapped to BAs

All major interfaces and critical contingencies are included in the model, based on Enelytix analysis of historically binding constraints

- High-voltage transmission elements are monitored for violations in the model

We plan to add additional constraints in the Carolinas as provided by transmission owners

Operating Reserves

Regulation, spinning, and non-spinning reserve requirements modeled

Reserve requirements defined as a percentage of load

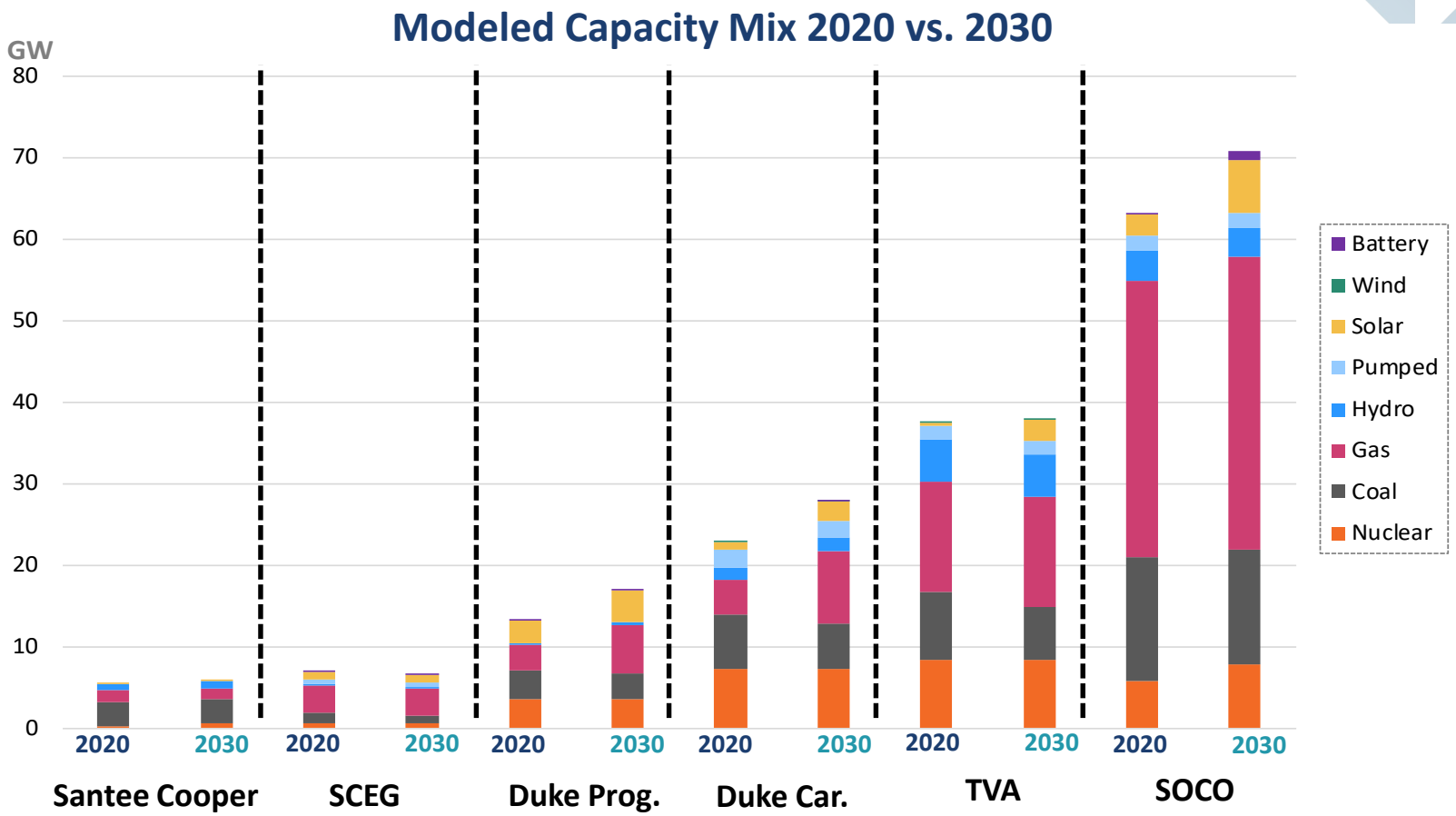
We intended to model lower reserve requirement under EIM and RTO reform options due to geographic diversity balancing renewable output fluctuations

Resource Mix By BA

Base inputs are based on S&P Global's generating asset database

We updated 2020 and 2030 inputs with utility IRP data and cross-checked with EIA information

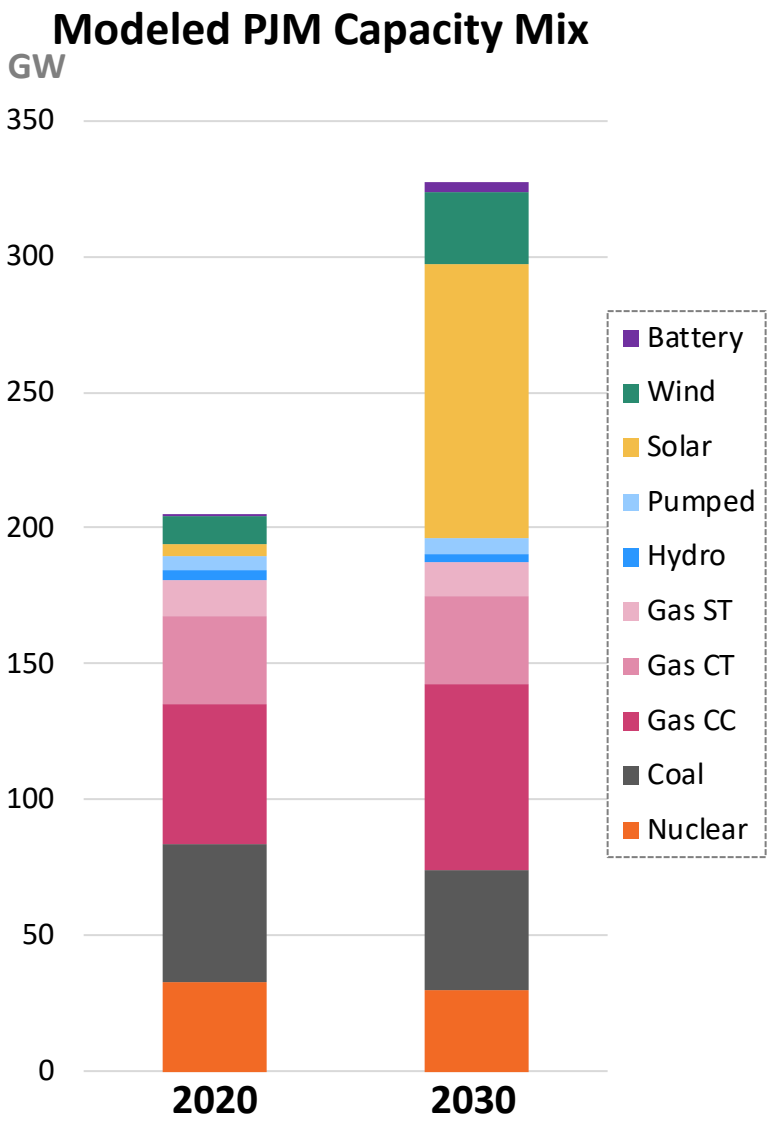
- Input from generation owners will be used to refine our 2020 and 2030 resource mixes based on public data
- Certain utilities have stated goals that are not yet in IRPs, like SOCO's RPS targets and TVA's small nuclear targets. We plan to implement generation resource mixes that align with those targets



PJM Resource Mix

We model 2030 resources based on PJM member states' renewable portfolio standard (RPS) goals

- **28%** of PJM load to come from renewables by 2030 based on existing policy (including solar carve outs)
- **75 GW** solar capacity and **9.4 GW** land-based wind added to achieve **135 TWh solar** and **70 TWh wind** generation goal by 2030
- Modeling **8.5 GW** of offshore wind procurement targets in PJM in line with existing state policies
- We are currently review all coal and nuclear plants in PJM to check announced plans for potential retirements



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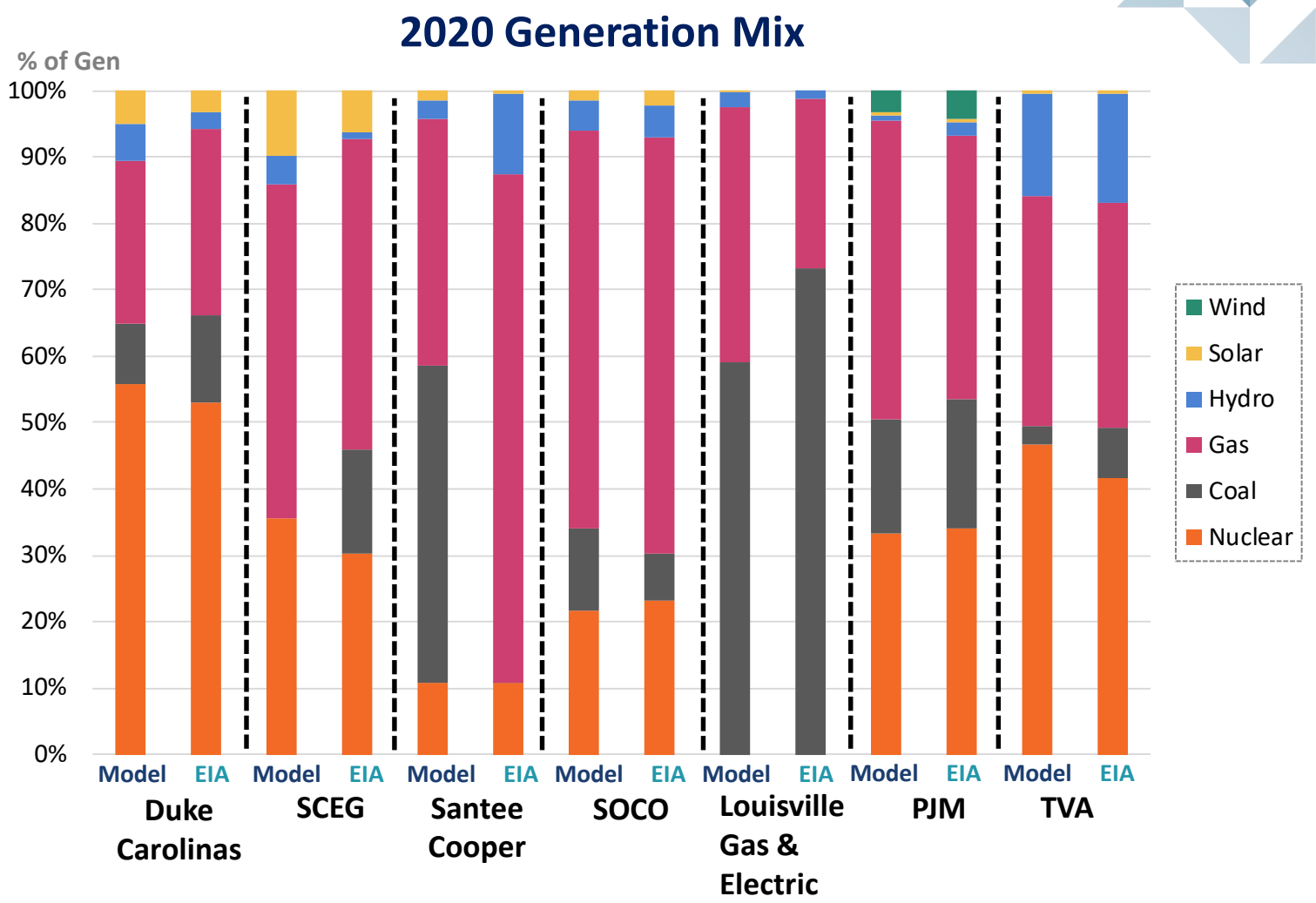
Generation Mix

We are benchmarking model results to 2020 generation data reported by EIA

We are currently calibrating thermal unit generation to achieve a realistic balance of gas and coal generation

- Peaking unit operating characteristics
- Fuel hub mappings
- Joint ownership and PPAs

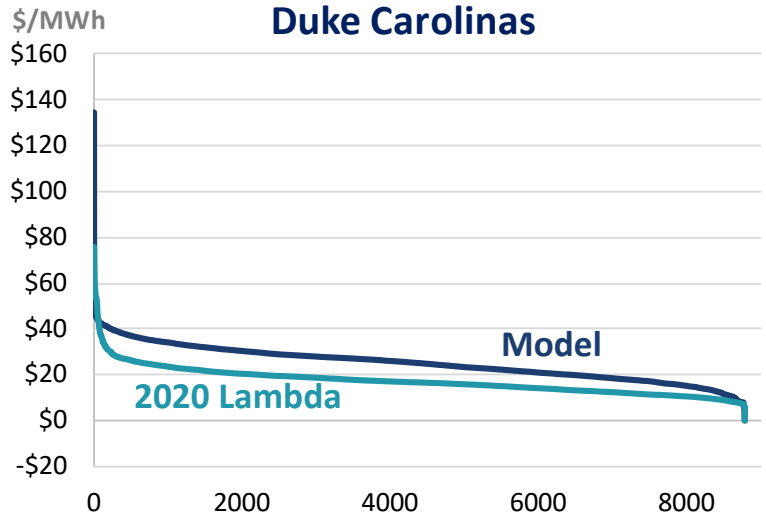
We are also examining hydro unit formulations and energy budgets

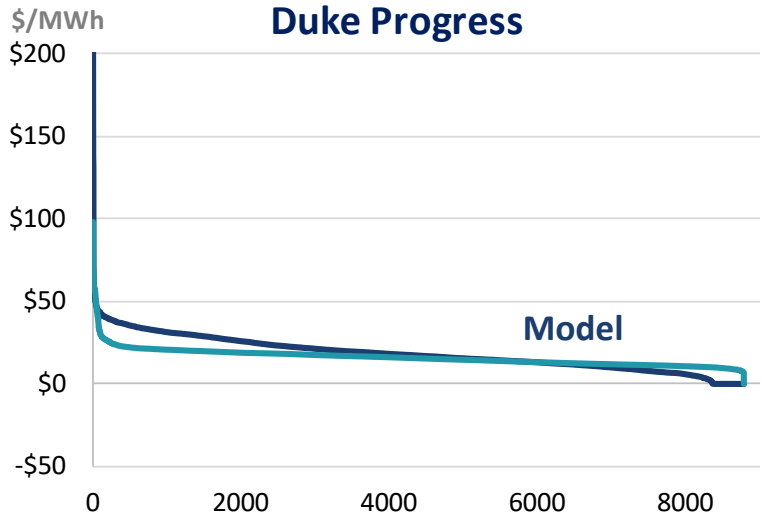


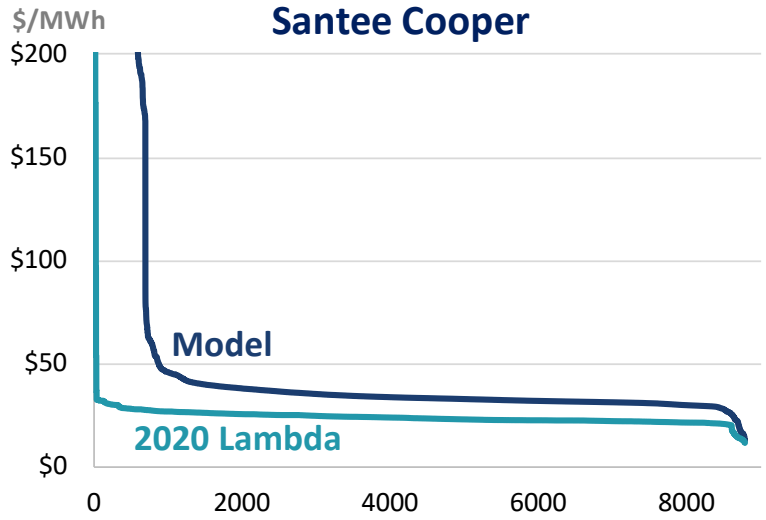
Carolina Entities' Energy Prices

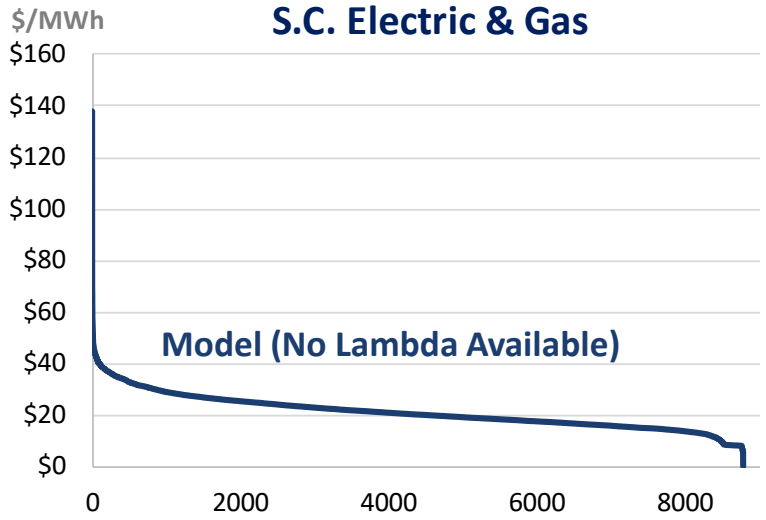
We are benchmarking simulated energy prices against 2020 historical system lambdas from FERC Form 714.

- Modeled energy prices tend higher for SC entities
- Refining coal and gas generation likely to help align modeled and historical





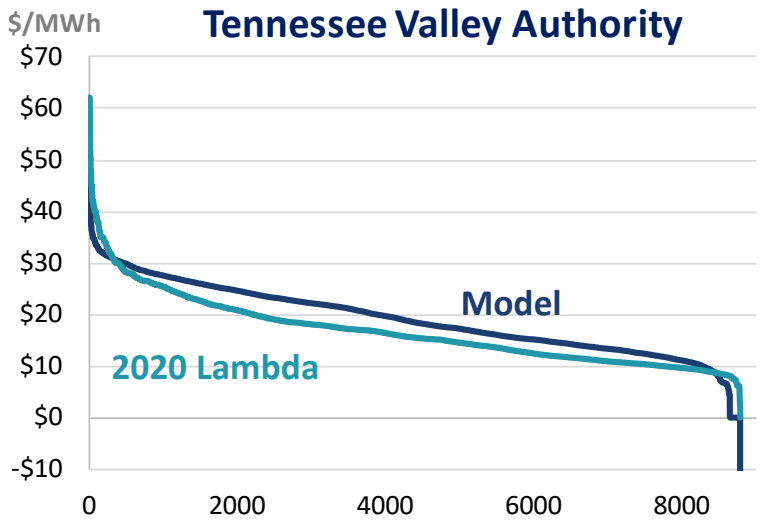


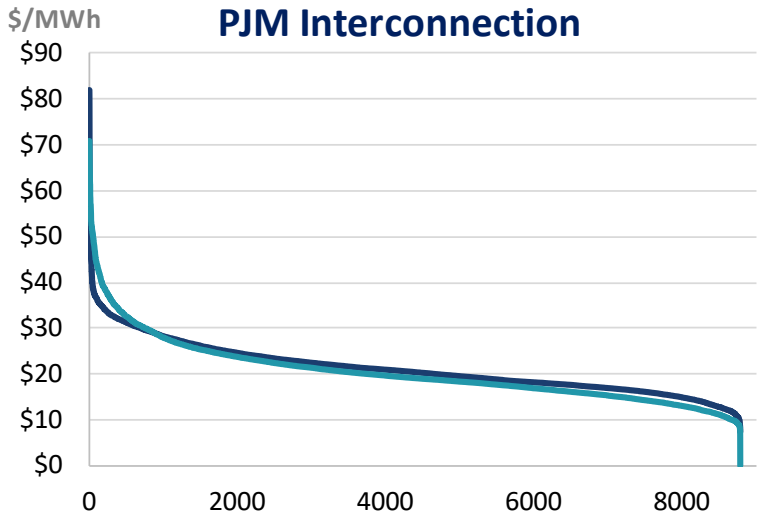


Price Benchmarking for Area Outside the Carolinas

In areas outside of the Carolinas, simulated prices roughly track historical system lambdas and prices

- **We continue to refine generation and fuel price assumptions to calibrate model outcomes against historical system costs and generation patterns**





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Next Steps

Refine modeling assumptions and gather data from Carolina generation and transmission owners

- Jointly-owned units, coal, nuclear, peaking capacity, and fuel prices
- Inter-BA trading and power purchase contracts
- Generation characteristics, fuel prices, trading
- Modeling existing/planned market structures (e.g., Duke JDA, SEEM

Model change cases for each market reform options

Evaluate benefits of market reform

Calculate costs and risk of market participation