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Santee Cooper IRP Stakeholder Process 2024-2026

Stakeholder Working Group Meeting #7 – Meeting Summary

Date: June 4, 2025

Time: 1:00 pm – 3:27 pm EDT

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #7

This summary includes meeting logistics, presentations, and discussions.
It is organized into the following sections:

- Meeting Information & Materials
- Session Participation
- Topics, Presenters, and Discussion
- Commitments and Next Steps
- Appendix - List of External Stakeholder Working Group Members & June Meeting Attendees

Meeting Information & Materials

The Santee Cooper Resource Planning team held its seventh IRP Stakeholder Working Group meeting on Wednesday, June 4th, 2025. The IRP Stakeholder Working Group is integral to Santee Cooper's commitment to engage stakeholders in its ongoing integrated resource planning process. The meeting covered Santee Cooper's 2025 Integrated Resource Plan (IRP) update, which included load forecasting, fuel and resource assumptions, renewable and thermal resource costs, updates on battery storage projects, and potential modeling strategies for future energy resource planning. The presentation shared during the meeting is posted to the Stakeholder Working Group section of the [Santee Cooper 2024-2026 IRP Stakeholder Process webpage](), along with summaries from the first six working group meetings.

Session Participation

The Stakeholder Working Group includes a set membership of organizations representing diverse interests and perspectives, including government, regulatory agencies, and environmental, social, and customer groups. The Santee Cooper Resource Planning team invited each organization to join the working group and assign a primary and secondary member.

Appendix A lists the working group member organizations and the members who attended the June 4th meeting.

Topics, Presenters, and Discussion

The presentation, which included the meeting agenda and associated timing, was emailed to members on March 11, 2025.

Welcome and Agenda
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart Ramsay opened the seventh meeting of the Stakeholder Working Group with a welcome and a review of the agenda. He noted this was the seventh in a series of working group meetings. He outlined that Clay Settle would cover working group business for about an hour, followed by a short break, after which Clay and Bob Davis (nFront Consulting) would present the 2025 IRP update. Carl Ciullo would discuss the 2025 load forecast towards the end of the meeting. Stewart emphasized that there would be plenty of time for conversations and that the agenda could be adjusted as needed to ensure all topics are adequately discussed.

Working Group Business
– Clay Settle, Manager, Resource Planning, Santee Cooper
– David Millar – Director, Resource Planning, Santee Cooper

REVIEW OF ACTION ITEMS

April 10 Coal Retirement Technical meeting: Clay noted this was complete. Comments from Coastal Conservation League (CCL) and Southern Alliance for Clean Energy (SACE) had been received and discussed.

Jefferies-based battery energy storage system (BESS) RFP: David Millar provided an update noting strong interest in the RFP, receiving around 30 proposals from nationally recognized developers. Initial evaluations are complete, and the team is working toward a shortlist. While the process is still ongoing, early pricing results were described as "very good," attributed to favorable tax incentives, energy community bonuses, and the project's ready interconnection status. Further updates are expected at the next meeting.

- Eddy Moore (Southern Alliance for Clean Energy) asked about the level of megawatts involved. David replied that Santee Cooper had requested bids for battery storage in three sizing options—100 MW, 200 MW, and 300 MW. While the immediate need is for 100 MW, longer-term capacity requirements are under consideration, including potential phased development. The RFP yielded approximately 90 proposals across the size options from about 30 bidders.
- Eddy asked whether the battery storage project under discussion is in addition to the 130–150 MW of storage planned by Central; David confirmed it is. Eddy's follow-up questions focused on whether the evaluation would include scenarios for all three size options (100, 200, 300 MW). David confirmed that as part of a broader portfolio assessment, the full range of sizing scenarios is being considered, with system cost impacts analyzed through comparative modeling.

Sharing of stakeholder feedback on tracking potential economic development load with the Load Forecast Group: Clay reported this would be addressed later in the current meeting as part of Carl Ciullo's load forecast presentation.

2024 thermal resource cost assumptions alongside the 2025 assumptions: Clay indicated this action item was complete, and a comparison slide would be presented as part of the assumptions discussion.

Energy Resource Interconnection System (ERIS) and Provisional Interconnection System (PIS): Clay confirmed the Resource Planning team received docket information (Docket No. 2019-326-E) but did not receive any additional feedback from members. The available information was shared with relevant subject matter experts (SMEs) at Santee Cooper.

REVIEW OF FEEDBACK RECEIVED

Clay reviewed stakeholder feedback received to date. This included two letters from CCL and SACE concerning the market potential study and demand-side management programs. These topics will be discussed once Market Potential Study (MPS) results are available in future scheduled working group sessions. Additional feedback is still under review and will be addressed as the process continues. Further input from CCL and SACE addressed topics including coal retirement, reliability assessment, large load forecasting, and renewable integration. Coal retirement was covered in a dedicated technical session, and reliability assessment was discussed at the last meeting, and is expected to be discussed at future meetings. Further reliability analysis, specifically portfolio evaluations using loss-of-load expectation modeling, is planned for the 2026 IRP. Renewable integration will be addressed in the next working group session sometime in October. Clay emphasized the intention to transparently communicate stakeholder feedback and how it will be incorporated into the process.

SWG WORKING GROUP SCHEDULE

Clay reviewed the ongoing stakeholder engagement process and previewed upcoming content. This meeting focused on the 2025 IRP update, including updated assumptions, portfolio strategies, and the 2025 load forecast. Future meetings will address state legislative impacts on IRP planning, updates on the coal retirement study, integration and hydrogen studies, federal funding opportunities, demand side management (DSM) modeling for the 2026 IRP, reliability and reserve margin studies, effective load carrying capability (ELCC) analysis, and wind study updates from Santee Cooper's research and development (R&D) team.

Additionally, Clay noted ongoing workflows: the 2025 load forecast is complete and will be presented today, with another update planned for the 2026 triennial IRP. Market potential studies are underway with stakeholder involvement, and reliability studies, led by PowerGEM, are also in progress. Updates will be shared as they become available.

- Findlay Salter (South Carolina Office of Regulatory Staff (ORS)) asked when the Coal Retirement Study would be available for review. Clay replied that once transmission planning estimates are ready in late August, the study will formally kick off in the fall, timing the full study or comprehensive update expected by February. He clarified that the transmission component of the Coal Retirement Study is expected to be available by the October meeting, allowing for an initial update at the next working group session.

2025 SCHEDULE

Clay reviewed the 2025 IRP schedule, highlighting the progress made and upcoming milestones. Resource Planning has held two general notice meetings and multiple technical sessions, and this is the seventh Working Group Meeting. Another working group session and a third general notice meeting are planned for later this year. In August, stakeholders who sign a non-disclosure agreement (NDA) can gain access to IRP modeling data through the data room. The 2025 IRP Annual update will be filed in September, initiating another formal proceeding process.

- Stewart suggested that the next working group meeting include time to gather input from the members on topics for the November General Notice Meeting. The intent is to leverage the working group's technical expertise to prioritize subjects for the broader, more accessible General Notice sessions. Clay agreed and welcomed feedback to shape the upcoming agenda.

2024 IRP Update and 2025 IRP Update

– Clay Settle, Manager, Resource Planning, Santee Cooper

– Bob Davis, Executive Consultant, nFront

ASSUMPTIONS, PORTFOLIOS, SENSITIVITIES AND METRICS

Clay provided an overview of key modeling assumptions for the 2025 IRP Annual update, following a structure like the one used in the 2024 update.

Financial Assumptions: Santee Cooper's weighted cost of debt is set at 5%, the short-term commercial paper at 4%, a discount rate of 5%, and a general inflation rate of 2.6%, which is based on internal corporate escalation practices.

Demand-Side Management (DSM): The utility will maintain the same DSM assumptions used in the 2024 IRP update, consistent with the 2023 IRP. These will be revised in the 2026 triennial IRP to reflect the results of the new market potential study currently underway.

Planning and Operating Reserves: The planning reserve margins remain at 18% for winter and 15% for summer, in line with the 2023 IRP. Operating reserve requirements are being updated to reflect changes in the Carolina Reserve Sharing Group (CRSG), as Duke Energy consolidates its balancing authorities. This results in a stepped increase in Santee Cooper's operating reserve obligations from 235 MW in 2025 to 295 MW by 2030, with recalculations occurring annually.

- Findlay asked whether the increased operating reserve requirements were solely due to Duke Energy's merger of balancing authorities or if Santee Cooper's coal retirement and new resource projections also played a role. Clay and Bob clarified that the most severe single contingency is based on generating units within the balancing authorities and their potential unavailability. The increase in operating reserve requirements stems from the shift from four balancing authorities sharing reserves to only three, due to Duke's consolidation. The contingency itself hasn't changed—only how the obligation is allocated. Clay offered further technical clarification offline if needed.

Bob discussed the fuel forecast and shared that Santee Cooper has updated its fuel price assumptions for the 2025 IRP filing using the most recent *Annual Energy Outlook (AEO)* from the U.S. Energy Information Administration (EIA) data, which was not available for the 2024 IRP update. The *AEO* serves as the basis for base, high, and low fuel price forecasts for natural gas, coal, and diesel. For the near term (2025–2029), forward Henry Hub prices from the Chicago Mercantile Exchange (CME) are used to reflect current market conditions, although this has minimal impact on the IRP since most new resources are planned for the 2030s and beyond. Furthermore, regional hub adjustments (e.g., Transco Zone 5) are based on S&P Global Platts forecasts, with monthly price patterns derived from CME forward data. Delivered natural gas prices include adjustments for pipeline tariffs where applicable. Overall, the updated base case prices are approximately 27% higher than in the 2024 IRP, primarily due to changes in the EIA's outlook.

- Taylor Allred (Coastal Conservation League) asked which *AEO* cases were being used for fuel price forecasting. Bob clarified that the medium (base) forecast relies on the *AEO* Reference case. The low-price scenario is based on *AEO*'s High Oil and Natural Gas Technology case, which assumes more advanced and widespread development of extraction technologies, resulting in increased supply and lower prices.
- Taylor asked if this was the high oil and gas supply case? Bob clarified that this was the low-price case, which reflects the High Oil and Natural Gas Technology *AEO* scenario, where improved technology and increased well development boost supply and reduce prices. Conversely, the high price case utilizes the Low Oil and Natural Gas Technology *AEO* scenario, which assumes slower

technological advancements, fewer new wells, and greater regulatory constraints, factors that reduce supply and drive prices higher.

- Eddy raised a question about the modeling of pipeline tariff charges, specifically whether only variable charges were included. Bob clarified that variable pipeline tariffs are included in the delivered fuel price forecasts, while firm transportation (FT) charges are modeled separately as fixed costs for all new resources. The FT charge assumption has changed slightly from last year but remains closely aligned with ongoing industry discussions.

Bob reviewed the coal price forecast used in the 2025 IRP, which shows low variability across scenarios, consistent with last year's 2024 update. This reflects a U.S. market where coal demand remains low due to continued coal plant retirements, resulting in little pricing pressure despite long-term supply.

Source & Method: Santee Cooper's forecast draws on the *AEO* projections for mine-mouth prices in the Illinois Basin, Central Appalachian, and Northern Appalachian regions—fuels used at Winyah and Cross stations. Delivered price modeling centers on Cross Units 3 and 4, where most of the system's coal is consumed.

Blending & Budget Alignment: The fuel price mix reflects Santee Cooper's current 10-year coal blending and budgeting strategy, including freight costs (confidential unless under NDA), fuel handling, and rail car maintenance.

Forecast Anomalies: In some years of the *AEO*, there are *reversals in the high and low-price scenarios*—a modeling artifact tied to national retirement schedules and shifting demand. Santee Cooper plans to smooth these anomalies to preserve a traditional ascending price order (low < medium < high).

Year-over-Year Comparison: On average, medium-case coal prices are 32% higher than those used in the 2024 IRP, mirroring a similar rise in gas prices (+27%), both primarily driven by updated AEO projections.

- Findlay asked about the drivers behind the 27% increase in natural gas prices and the 32% increase in coal prices in the latest AEO compared to the previous year's forecast. Bob acknowledged that he did not yet have a clear explanation. He noted that the *AEO* underwent a full model revamp, but he had not reviewed the accompanying documentation to determine whether the changes stemmed from updated methodology, shifting market conditions, or both. He committed to looking into it further and sharing any findings at a future meeting or sooner if possible.
- Clay clarified that the apparent price increases are being compared to the 2023 IRP assumptions, which are still based on the 2022 *AEO* forecast, as the U.S. EIA did not release an update in 2023. Bob confirmed this, noting that the new forecast reflects a two-year gap during which significant macroeconomic changes have occurred. This time lag helps explain why the updated *AEO* shows substantial increases in fuel price projections, although the specific drivers still require further review in detail.
- Stewart suggested that instead of waiting until the next stakeholder meeting in October, the team could prepare a brief summary of key drivers behind the fuel price forecast increases once they've had time to review the updated *AEO* documentation. Bob agreed and committed to posting that summary to the IRP stakeholder website once it's available.
- Findlay asked for clarification on whether the recent increases in fuel prices were due to commodity costs or other factors such as firm pipeline transportation or rail fees. Bob confirmed that the increases are driven almost entirely by underlying changes in commodity prices, as reflected in the latest *AEO*, rather than by shifts in transportation or delivery costs.

Bob then briefly outlined Santee Cooper's carbon pricing assumptions. For the 2025 IRP update, Resource Planning will continue modeling CO_2 price sensitivities using the same framework as in the 2023 IRP and

2024 update. The low case assumes no CO_2 cost, while the medium and high cases are based on the Social Cost of Carbon as defined by the U.S. Interagency Working Group in its February 2021 report. Since no new federal guidance has been issued since then. Santee Cooper recommends continuing with the same CO_2 pricing assumption.

Clay continued with a detailed overview of Santee Cooper's existing resource fleet and current power purchase agreements (PPAs), along with updates on modeling assumptions for thermal resources in the 2025 IRP.

The Cross Generating Station, a four-unit coal plant with a total capacity of approximately 2,300 MW, is set to operate through the study period in the base IRP update and through 2032 under greenhouse gas (GHG) sensitivity scenarios. The Winyah Station, another large coal facility with about 1,100 MW capacity, is slated for retirement by 2033 in the base case and 2032 under GHG scenarios. The Rainey site, a gas plant located in Anderson, SC, features a combined cycle (CC) and multiple combustion turbines (CTs), with upgrades underway that will increase total winter capacity by approximately 250 MW. These upgrades encompass a combined cycle conversion, enhancements to existing units, and improvements to peaking CTs. Cherokee, another natural gas site, will continue operations through the study period.

Santee Cooper's joint ownership in V.C. Summer Unit 1 continues through the planning horizon, along with hydro facilities at Jeffries and Spillway Lake Moultrie (142 MW), landfill gas units (around 26 MW, modeled according to contract expiration), and two peaking CT plants at Myrtle Beach and Hilton Head, scheduled for retirement by 2034.

In terms of contracted resources, the utility holds approximately 463 MW in long-term variable hydro contracts, and about 487 MW of solar through existing PPAs. An additional 672 MW of Central-non-shared resources are expected online in 2029. Overall, PPAs total roughly 2,000 MW, although this number doesn't yet reflect any outcomes from the most recent capacity RFP. Any new PPAs pursued from that process will be incorporated into the IRP modeling.

Finally, Clay explained the methodological updates for thermal resource assumptions. In past IRPs, data for operations, maintenance, and capital costs were sourced from EPRI's Technical Assessment Guide for the Web TAGWeb™, Black & Veatch studies, and internal engineering estimates. For the 2025 update, Sargent & Lundy provided updated assumptions for O&M costs, operating characteristics, and capital expenses. These figures were further adjusted to align with Dominion's 2024 IRP and general inflation trends in the industry.

- Findlay asked how the recently discussed capacity RFP, seeking up to 1,500 MW beginning in 2026, fits into the IRP framework. Clay clarified that this RFP is distinct from the current list of existing PPAs shown in the presentation. The utility is actively evaluating proposals for capacity and energy contracts of up to 20 years, and the results of that process will be incorporated into the IRP modeling. Depending on the outcome and contract terms, selected PPAs may be treated as either fixed additions or selectable options within the resource plan.
- Findlay followed up by asking how the ongoing battery storage RFP fits into the IRP framework. Clay explained that the approach is similar to the capacity RFP, while a selection hasn't been finalized, the evaluation is in progress. The 2024 IRP update targets 240–250 MW of near-term battery storage, and the current RFP aims to fulfill that need. Once selections are made, those battery storage resources will be treated as fixed additions in the IRP resource plan, rather than optional or selectable modeling elements.
- Eddy explored whether recent capacity procurement moves might be driven by or tied to emerging load pressures from large customers seeking autonomy or custom supply deals, and whether the utility is overbuilding. Clay responded by clarifying the exploratory nature of the RFPs and detaching them from any specific off-system customer arrangement. Eddy pointed to potential unresolved

issues, particularly regarding the reported large-customer interest, which Clay committed to investigating.

Clay shifted the presentation to an overview of the thermal resource assumptions for the 2025 IRP update, developed in partnership with Sargent & Lundy. A key change in this year's modeling is the decision to focus exclusively on 1x1 combined cycle gas turbines (CCGTs), as opposed to larger 2x1 configurations, due to operational constraints in a relatively small balancing authority like Santee Cooper. Larger units (1,200–1,300 MW) pose challenges for maintenance scheduling and grid reliability, especially when offline.

To explore economies of scale**,** SNL provided capital cost estimates for building one, two, or three 1x1 units simultaneously. As expected, costs per kW decrease with multiple installations: approximately $1,720/kW for a single unit, $1,576/kW for two, and $1,453/kW for three built at once. These costs are reported as overnight costs only, excluding expenses like interconnection, transmission, water, and financing, unlike previous IRPs.

The team is modeling discrete build options: one unit, two units, and 50% of three units, allowing the planning model to explore partial or staged implementation.

Other thermal technologies included in the analysis are:

- H-class and F-class combustion turbines, consistent with prior IRPs
- Aero-derivative turbines and reciprocating internal combustion engines (RICE), standardized to ~100 MW for consistency and comparability, and
- A revised small modular reactor (SMR) assumption, now modeled as a 300 MW unit with an updated capital cost exceeding $11,000/kW, reflecting increased projected costs

These updates are intended to improve modeling realism, reflect current industry trends, and support more flexible, site-scalable planning decisions.

- Steven Thomas (Century Aluminum) asked whether the modeled 1x1 CC units are designed with the potential for future expansion into 2x1 configurations. Clay responded that the 1x1 units being modeled are not designed for future expansion; they are intended to remain as they are. However, if future flexibility were desired, it might make more sense to start with an H-class or F-class simple cycle CT configuration, with the option to convert it into a combined cycle unit later. This would provide a clearer pathway to expansion, though it is not currently part of the 1x1 CCGT assumptions in the IRP.
- Findlay asked whether the Sargent & Lundy report informing the updated thermal resource assumptions was connected to the *AEO* or independently commissioned. Clay clarified that the report was commissioned directly by Santee Cooper and is not part of the *AEO*.
- Findlay asked why 2x1 CC units weren't included as resource options. Clay explained that operational feedback indicated these large units (1,200–1,300 MW) are too difficult to manage within Santee Cooper's small balancing authority, especially regarding maintenance scheduling. No formal cost-benefit analysis was done; the decision was based on practical input from plant operations. Only the scenario involving three 1x1 units assumes joint ownership with Dominion. Findlay also suggested modeling multiple SMRs to reflect typical deployment practices, and Clay agreed to consider it and discuss it with Sargent & Lundy.
- Findlay asked whether any resources are being locked into the IRP portfolio. Clay confirmed that 50% of the three 1x1 CC units will be treated as fixed in the plan, based on prior IRP modeling and ongoing due diligence for a potential joint build. Findlay noted that this specific configuration hasn't been previously selected by the model and recommended including an unconstrained optimization case to test economic competitiveness. Clay agreed to consider it and provide an update after internal discussions.

- Steven Thomas asked about the difference in heat rate between 2x1 and 1x1 CC units. Bob responded that the heat rates are virtually the same, indicating minimal efficiency difference between the two configurations.
- Nina Peluso (Energy Futures Group for Southern Environmental Law Centre) noted the decline in CT costs on an overnight basis and asked whether the modeling uses only those base costs or includes additional factors like land, interconnection, and financing. Clay clarified that while the IRP modeling includes full costs, the comparison table shown uses only overnight capital costs to allow for consistent benchmarking, given that assumptions for add-ons vary widely across utilities. Nina suggested it would be helpful to also see the additional cost components, even in aggregate, to better understand the total modeled costs driving decisions. Clay acknowledged the value of that perspective and stated that the team would take it under consideration.
- Eddy noted that Dominion’s prior modeling showed significant cost savings when four aero-derivative CTs were installed together, compared to just two. He suggested that Santee Cooper consider modeling four-unit groupings to capture those potential economies of scale. Clay acknowledged that larger groupings do tend to lower per-unit costs but explained that the current two-unit assumption was chosen to align with site constraints and to maintain a consistent comparison with reciprocating internal combustion engine (RICE) units around the 100 MW scale. Eddy also asked whether the modeled 236 MW F-class turbine represented one unit or two, and Clay confirmed it is a single large-frame CT.
- Findlay asked whether the thermal resource cost assumptions being used were based on the 2024 joint request for information (RFI) with Dominion or on Santee Cooper’s Sargent & Lundy study. Clay clarified that the IRP assumptions come from a generic, non-site-specific study conducted by Sargent & Lundy in Q1 2025 and are not directly tied to the 2024 RFI. When asked whether these costs are more current than the RFI results, Clay said he wasn’t sure but agreed to follow up and investigate how the RFI results are being considered, especially since Dominion appears to have incorporated them into its IRP update.

RENEWABLE AND BATTERY ENERGY STORAGE COSTS

Jonathan Nunes (nFront Consulting) continued the presentation to cover cost assumptions for renewable and battery energy storage system (BESS) projects in the 2025 IRP update, modeled under PPA structures with taxable developers. Costs are presented as levelized cost of energy (LCOE) or capacity (LCOC) over the asset's life, using capital, O&M, and financing assumptions. For solar photovoltaic (PV), two scenarios are shown: one with production tax credits (reflecting the Inflation Reduction Act (IRA)) and one without, the latter serving as a possible sensitivity. Base-year capital costs are sourced from Sargeant & Lundy, while cost trends come from the conservative case in National Renewable Energy Laboratory (NREL) 2024 Annual Technology Baseline. A 30-year service life is assumed, with tax credits applied during the first 10 years. Notably, the levelized cost of solar in this IRP is about 37% higher than in the 2024 update, due to revised assumptions. The cost gap between tax credit and non-tax credit scenarios widens over time, as tax credits increase with inflation while solar capital costs remain flat or decline slowly.

- Hamilton Davis (Carolinas Clean Energy Business Association) asked whether Santee Cooper is considering a sensitivity that would help identify a price ceiling for solar, a point at which it no longer gets selected in the model, rather than simply projecting long-term technology cost trends. Jonathan responded that while such a sensitivity hasn't been planned, the two modeled cases (with and without tax credits) already provide a sense of where solar becomes uneconomic. Bob added that current assumptions under the tax credit scenario (the "blue line") generally align with, or are somewhat lower than, most recent solar RFP bids, except for a few low-cost offers. He also noted that solar additions in the IRP are not capped, and the model is allowed to build as much as it finds cost-effective—typically 1,500–2,000 MW by the time Winyah is retired. These additions are staggered in the early years to avoid unrealistic clustering. Jonathan clarified that while the blue line reflects reasonable expectations, real-world solar bids tend to come in higher, especially when accounting for uncertain transmission interconnection costs.

Jonathan then presented updated 2025 IRP cost projections for onshore wind, offshore wind, and BESS , based on the same modeling approach as for solar. All resources assume PPA structures with taxable developers, using base-year capital costs from Sargent & Lundy and trend assumptions from NREL's 2024 ATB (conservative case). Onshore wind includes production tax credits (PTCs) for the first 10 years of operation and shows costs about 24% higher than the 2024 IRP. The impact of tax credits is less pronounced than with solar. For offshore wind, where investment tax credits (ITCs) are more favorable, the updated projections are 39% higher than last year's, with the resource assumed to be available later in the study period. Battery storage projections were provided for both 4-hour and 8-hour systems. The cost framework assumes a 20-year service life (same as in the previous IRP), with ITCs applied to the "with-credit" case. The 4-hour battery costs are 17% higher, and the 8-hour battery costs are 14% higher than in the 2024 IRP. In both cases, the blue line reflects ITC availability, while the orange line shows the higher-cost no-ITC scenario. The structure and modeling logic are consistent across all resources.

Clay confirmed that the ELCC assumptions for the 2025 IRP update will remain the same as those in the 2023 and 2024 IRPs. ELCC represents the portion of an intermittent resource's capacity that can reliably contribute to meeting peak demand—essentially its "firm capacity" value. A new ELCC study by PowerGEM is currently underway, and its results will be incorporated into the 2026 triennial IRP update.

- John Burns (Carolinas Clean Energy Business Association) asked whether the current ELCC values account for the synergistic benefits of solar and battery storage when used together. Clay replied that, for this update, ELCCs remain resource-specific and follow the same methodology from past IRPs. However, with the EnCompass upgrade, there's now an opportunity to model the synergistic value of combined resources. This feature will be tested and may be incorporated into the 2026 triennial IRP. Bob added that while the current curves treat each resource separately in EnCompass, the original ELCC development did account for some synergistic value between solar and storage. The ongoing ELCC study by PowerGEM for the triennial IRP will further explore these effects.

Clay concluded by reviewing key updates to resource availability dates and modeling strategies for the 2025 IRP. First-year availability dates were largely consistent with previous IRPs, with minor changes: solar availability begins in 2028, batteries in 2027, and aero derivatives in 2028. Onshore wind has been pushed to 2034 pending further study, while offshore wind and nuclear SMRs remain targeted for 2040. First-year availability for CCs and CTs are assumed for the early 2030s.

Modeling strategies largely mirror the 2024 IRP update, including three portfolio approaches: one that locks in key 2023 IRP preferred resources, an optimized portfolio without pre-selections, and a GHG-compliant portfolio reflecting EPA 111 rules. The key difference between reference and GHG portfolios lies in retirement assumptions for coal units and capacity factor constraints on gas resources. The GHG scenario assumes earlier coal retirements and emission-limited dispatch of gas units due to the infeasibility of co-firing or carbon sequestration.

Portfolio evaluation will again use standard metrics, including net present value (NPV) power cost, min-max regret, reliability uncertainty, fixed cost obligations, CO_2 emissions, generation diversity, clean energy, load uncertainty and average cost or rate impacts. The process aims to ensure that the selected plan is resilient, cost-effective, and regulatory-compliant under a range of future scenarios.

2025 Load Forecast
– Carl Ciullo, Financial Analyst, Load Forecast, Santee Cooper

Carl presented Santee Cooper's finalized 2025 load forecast, which remains methodologically consistent with previous IRPs, incorporating updated assumptions and recent data. The theme of this year's outlook is stable with slight upward adjustments due to demographic trends and refined modeling inputs.

Residential and Commercial: Small short-term demand decreases stem from recent lower weather-normalized usage, but long-term growth is driven by continued in-migration (~1.4% CAGR). A key shift is the leveling of declining electricity use per customer, attributed to slowing natural gas penetration in new homes. Electric vehicle load is slightly up, rooftop solar adjustments remain consistent, and smaller, less energy-intensive commercial loads (e.g., medical offices, retail) are all moderating overall commercial growth.

Industrial: There has been minimal change year-over-year. Slight declines in non-firm energy and winter coincident peak reflect actual recent usage trends and not shifts in contracts or operational outlook.

Central Cooperatives: A significant increase in Central's forecast is due to two large industrial customers moving from the "potential large load" stochastic category into the base forecast. Central also continues to experience robust residential and commercial growth, driven by demographic expansion.

Stochastic Analysis (New Large Loads): Although the total modeled load is slightly lower than last year, this reflects two large customers signing contracts and moving into the base forecast. The analysis now includes 24 prospective customers (12 new, 11 dropped), one of which features behind-the-meter generation—*a first*—which reduces its peak contribution. This characteristic has been incorporated into the model for the first time based on stakeholder feedback.

Overall, while the structure of the forecast remains stable, refined inputs and continued growth across service territories are leading to a modest increase in projected long-term demand.

- Findlay inquired about attrition in the stochastic large load analysis. Carl replied that 11 projects previously under consideration have dropped off and are no longer being tracked. However, this has been offset by an influx of new inquiries, resulting in a net increase in potential load. Despite this, the overall forecasted contribution from stochastic customers is slightly lower than last year due to the reduced probability of those new loads materializing. Carl characterized the situation as more prospective load, but with a lower average likelihood of realization.

Carl explained that while the stochastic load forecast appears lower this year, it's primarily due to two large customers moving into the base load forecast**,** rather than a reduction in actual demand. In reality, the total potential large load interest has increased.

Probability Bands: The P25–P75 range is tighter than last year, indicating a more stable forecast with less variance. This results from a shift toward a mix of more large or small customers, making extreme scenarios (i.e., many large customers onboarding at once) less likely and driving more outcomes toward the median.

OVERALL LOAD FORECAST

Near-term (2025–2028): Slightly lower than last year, mainly due to mild recent weather and updated early assumptions.

Mid-term (2029–2034): Forecast dips about 200 MW below last year's outlook, attributed to delayed onboarding of potential large load customers (by 18–24 months on average).

Long-term (post-2034): Load surpasses last year's projection, resulting in a ~225 MW higher coincident peak demand by the late 2040s.

In essence, despite some timing shifts, the updated forecast reflects continued long-term growth, with a smoother and more predictable projection profile.

- Eddy asked for the 2024 peak demand value to contextualize the forecast chart. Carl replied that he did not recall the exact figure but believed it occurred in January and committed to confirming it.
- Eddy further asked whether there is any overlap between the prospective large load customers in the stochastic analysis and those expressing interest in the nuclear RFP. Clay replied that, as per prior discussions about potential overlap between large prospective loads and interest in the nuclear RFP details are confidential and speculative at this stage. When asked about a timeline for more information on nuclear development, Clay clarified that no one on the current call is directly involved in that process and could not provide a timeline.
- Eddy asked if there should be a sensitivity that shows what happens when you add a nuclear plant. Stewart and Bob discussed the challenges of modeling potential impacts from a new nuclear facility, particularly around distinguishing how much generation would serve the broader system versus a co-located load. Carl clarified that the current IRP load forecast does not carve out or account for any such co-located or speculative nuclear-related loads. All loads reflected in the base and stochastic forecasts are independent of any assumptions about a potential nuclear project.
- Taylor asked about trends among large potential loads that have exited or entered the forecast since the 2024 update, and whether any insights have influenced probabilistic screening methods. Carl responded that, overall, the characteristics of incoming and outgoing customers remain similar, with no clear shifts in customer types, load profiles, or geographic issues. No new roadblocks or patterns have emerged that would warrant changes to how probabilistic screening is conducted.
- Taylor asked whether the attrition rate of potential large load customers aligned with prior probability estimates. Carl explained that the stochastic model is single-stage and does not simulate customer attrition over time. Instead, it assigns overall likelihoods of customers materializing but does not predict the *timing* or pace of drop-offs. As a result, there is no direct way to compare actual attrition against a modeled expectation on an annualized basis.

Meeting Close
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart closed the meeting with thanks and a review of action items (below). He reminded members to suggest prioritized topic discussions for the November General Notice Meeting, and confirmed a written summary of the meeting will be distributed for review and comment.

- Taylor asked whether there was a need for an additional action item around modeling the joint combined cycle resource. Clay proposed potentially adding a clarification to action item 3 (The team will consider including an *unconstrained or fully optimized sensitivity* in the 2025 IRP update.), which would allow the model to *select the joint build option* as part of a sensitivity case. Stewart committed to refining the wording and including them in the meeting notes.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion	By **WHOM**
1. Suggest topics for the November General Notice Meetings to Resource Planning	SWG Members
2. Provide a list of drivers that may be contributing to changes to the fuel price forecast to SWG members	Resource Planning
3. Consider a sensitivity that allows the model to choose the Joint NGCC as a selectable resource	Resource Planning
4. Consider how the 2024 RFI could influence assumptions for the Joint NGCC in the IRP Update	Resource Planning

Next Steps:

- The next Working Group meeting is targeted for October 2025
- The next general notice meeting is targeted for November 2025
- Members wishing to present a topic at a future meeting may contact Will Brown or Clay Settle

APPENDIX A

List of Stakeholder Working Group Members and Attendees

ORGANIZATION	MEMBER / ALTERNATE	June 4 ATTENDEE
Office of Regulatory Staff	Findlay Salter Jeffery Gordon Julian McElhaney **Shane Hyatt**	Findlay Salter Jeffrey Gordon Julian McElhaney Sam Christmus Shane Hyatt
SC Dept of Consumer Affairs	**Jake Edwards** Roger Hall	Jake Edwards
SC Dept of Natural Resources	Elizabeth Miller **Lorianne Riggin**	
SC Dept of Environmental Services	**Rhonda Thompson** Robbie Brown	Robbie Brown
Central	**Caleb Bryant** Leslie Maley	Heather Zrust
J. Pollock	Jeffry C. Pollock **Jonathan Ly**	Jeffry C. Pollock
Century Aluminum	**Michael Early** **Stephen Thomas**	Stephen Thomas
Nucor	**Bradley Powell** Karl Winkler	Bradley Powell
Messer	**Michael Peters** Steven Castracane	
Google	**Katie Ottenweller** Will Cleveland	
SC Association of Municipal Power Systems	**Adam Hedden** Eric Budds	
Individual	**Charles Hucks**	Charles Hucks
Individual	**Richard Berry**	
Individual	**Diane Bell**	
Individual	**Denny Boyd**	
Carolinas Clean Energy Business Association	Hamilton Davis **John Burns**	Hamilton Davis John Burns
Conservation Voters of South Carolina	Erin Siebert **Jalen Brooks-Knepfle** John Brooker	Jalen Brooks-Knepfle
Coastal Conservation League	Kennedy Bennett **Taylor Allred**	Taylor Allred
Energy Justice Coalition	Shayne Kinloch **Zakiya Esper**	
South Carolina Appleseed Legal Justice Center	**Sue Berkowitz**	
South Carolina Research Authority	**Greg Wilcox**	
Southern Alliance for Clean Energy	**Eddy Moore** **Maggie Shober**	Eddy Moore Maggie Shober

Southern Environmental Law Center	Anna Sommer Chelsea Hotaling **Kate Mixson** Nina Peluso Thomas Gooding	Chelsea Hotaling Kate Mixson Nina Peluso Thomas Gooding
Sierra Club	**David Rogers** Dori Jaffe Mikaela Curry Sari Amiel	Sari Amiel
Vote Solar	**Jake Duncan**	Jake Duncan
Santee Cooper Resource Planning	**Clay Settle** David Millar Rahul Dembla **Will Brown**	Clay Settle David Millar Will Brown
nFront Consulting	**Bob Davis** Jonathan Nunes	Bob Davis Jonathan Nunes
Santee Cooper – Load Forecast	Carl Ciullo	Carl Ciullo
Vanry Associates	Peter Claghorn **Stewart Ramsay** Yvette Smith	Peter Claghorn Stewart Ramsay Yvette Smith

**Members listed in alpha order by first name*

Also in Attendance

Santee Cooper	Max Hershberg
Central	W. Potter