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Santee Cooper IRP Stakeholder Process 2024-2026

Stakeholder Working Group Meeting #11 – Meeting Summary

Date: June 3, 2026

Time: 10:03 am – 3:02 pm EDT

Location: Virtual Meeting via Zoom, Vanry Associates facilitating

Meeting: Santee Cooper Stakeholder Working Group Session #11

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 eleventh IRP Stakeholder Working Group (SWG) meeting on June 3, 2026. The IRP Stakeholder Working Group is integral to Santee Cooper's commitment to engaging stakeholders in its ongoing integrated resource planning process. The meeting covered Santee Cooper's 2026 Load Forecast, the 2026 Integration Study, and the EnCompass Benchmarking results. The discussion also covered the 2026 Triennial IRP process, assumptions and filing, a review of working group business and member feedback. The presentation from the meeting is posted in the Stakeholder Working Group section of the Santee Cooper 2024-2026 IRP Stakeholder Process webpage, along with materials from the previous ten working group meetings and other related sessions.

Session Participation

The Stakeholder Working Group membership is comprised 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 represented with a primary and secondary member. A new organization was welcomed to the group in SWG Meeting 11: Southern Environmental Wind Coalition.

Appendix A lists the working group member organizations and the members who attended the June 3rd meeting.

Topics, Presenters, and Discussion

The presentation, which included the meeting agenda and associated timing of the various conversations, was emailed to members on May 28, 2026.

Welcome and Agenda

– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart Ramsay opened the meeting by outlining the session agenda. Discussion topics included a review of the working group business and action items, a 2026 load forecast update, and 2026 integration study results. Following a midday break, the discussion turned to the 2026 IRP and EnCompass benchmarking results. Stewart noted that the final agenda item would be a 20-minute stakeholder feedback session, as this would be the last working group meeting of the current IRP cycle before the regulatory filing.

Stewart also welcomed the newest working group member, Jocelyn Giuliano, Central Atlantic Program Manager with the Southeastern Wind Coalition. Jocelyn introduced her organization as a 501(c)(3) nonprofit advancing land-based and offshore wind energy across 11 southeastern states, with a focus on economic development outcomes for residents, customers, and utilities. She noted that while the Coalition does not formally intervene in IRP proceedings, it serves as a technical resource for partners who do, and she expressed appreciation for Santee Cooper's stakeholder engagement process. Jocelyn indicated that the Coalition's participation in the working group is intended to contribute to conversations on pathways to develop wind energy resources in South Carolina.

Working Group Business

– Will Brown, Manager Resource Planning, Santee Cooper

Will Brown reviewed outstanding action items from Meeting 10 and the coal retirement Technical Meeting, noting that most of the open items would be addressed through the day's presentations. Regarding modeling a two-on-one combined-cycle configuration as a sensitivity, Will confirmed that Santee Cooper does not intend to model this technology choice, due to concerns about becoming the system's single largest contingency, increasing the required operating reserves, and complicating unit scheduling and maintenance planning. Bypass upgrade options were explored but did not eliminate the contingency exposure, effectively shifting the largest contingency from Cross at approximately 600 MW to a unit in the 1,200-1,300 MW range.

Will also summarized the results from transmission studies for two Cross retirement scenarios: full and partial retirements of Cross Units 1 and 2. Scenario-specific siting assumptions drove much of the variation in the range of cost estimates. Will confirmed that costs would be incurred through retirement and that full avoidance is not feasible. The modeling approach, running retirement cases at five-year intervals, is expected to capture the trend value of earlier retirement in reducing future maintenance expenditures.

- Anna Sommer (Energy Futures Group on behalf of SELC, CCL) raised a question about whether the O&M assumptions in the model account for the reduced capital spending that typically occurs as generating assets approach retirement - a pattern sometimes described as maintenance starvation - and whether avoided costs of that nature are explicitly captured when evaluating different retirement dates. Bob Davis (nFront Consulting) clarified that for the Cross retirement scenarios, Santee Cooper models incremental and avoided O&M (operating and maintenance) costs based on budgetary forecasts developed with generation staff but does not explicitly assess whether specific capital expenditures could be avoided in the years immediately before retirement. Instead, the model simulates budgeted costs through the year preceding the modeled retirement date.

  Bob explained that, given the use of discrete five-year retirement increments, the team determined that explicitly monetizing the avoided capital costs, near retirement, would introduce a false sense of precision. Instead, the approach will be to review costs incurred just before each modeled retirement date, assess their magnitude, and compare them against the net present value differences across retirement scenarios to determine whether avoided CapEx (capital expenditures) would be sufficient to alter the conclusions.

Anna noted that she had observed cases in other IRP processes where retirement timing avoided hundreds of millions of dollars in capital expenditure, which was the basis for her question. She acknowledged Bob's explanation and agreed that amounts in the tens of millions of dollars were unlikely to alter the overall findings.

2026 Load Forecast Update
– Carl Ciullo, Financial Analyst, Santee Cooper

Carl Ciullo presented results from the recently completed 2026 IRP load forecast, noting that high and low cases are expected to be finalized in the following month. The forecast shows strong continuity with the 2025 IRP update for directly served residential and commercial classes, with a modest near-term increase in demand of about 10 MW. Without Santee Cooper's recently implemented three-part rates, the increase would have been 20 to 30 MW. Customers have responded meaningfully to the pricing signal, dampening coincident peak demand in a way not yet captured in historical data. The energy forecast closely tracks last year through the near term but shows a slight decline in later years due to an anticipated softening of Santee Cooper's penetration in all-electric new construction the expansion of natural gas distribution in the service territory begins to take effect.

Carl also reported updates to the EV forecast based on actual customer data: observed energy consumption from EV charging is substantially lower than previously assumed, as customers are driving less than modeled, while demand is marginally higher due to greater-than-expected charging activity during morning peak hours in January. The industrial forecast predicts a significant near-term increase, driven primarily by a substantial capacity expansion by a single large existing customer expected to come online in 2027. Carl clarified that the forecast only considers existing signed-contract customers, with potential new large loads addressed separately. He noted that approximately three-quarters of the 2027 increase is non-firm load, which tempers the overall impact on load growth but does not eliminate it. Beyond the first three years, the industrial forecast remains flat because the methodology relies on recent customer performance, near-term operational indicators, and existing contract terms rather than long-range projections.

- Findlay Salter (Office of Regulatory Staff) asked for clarification on the industrial load chart legend, noting difficulty distinguishing firm from non-firm load in the winter peak bar graph. Carl explained that the split is indicated by a subtle white border on the dark green bars rather than a color difference. Approximately two-thirds of the total TPU load are non-firm, and one-third is firm. Carl confirmed that the 2027 increase reflects growth in both firm and non-firm load, with non-firm accounting for the larger share, roughly three-quarters of the customer expansion driving that year's increase. Stewart noted that enlarging the slide suggested the firm/non-firm boundary sits at approximately 270 MW in 2026, rising to around 350 MW in 2027, and that the slide could be updated in the final distributed version to improve legibility.
- Eddy Moore (Southern Alliance for Clean Energy) asked whether the near-term industrial load should be understood as load migrated from the forecast of large potential loads into the signed customer base or as an entirely separate category. Carl confirmed that the bulk of the increase reflects exactly that transition, with potential large loads moving from prospective to contracted status.

Carl reviewed the Central Electric Cooperatives (Central) forecast, which predicts substantial near-term growth driven by two factors. First, a large number of potential large load customers were migrated into the base forecast, resulting in similar winter coincident peak and energy sales curves in the near term. Second, strong household formation across South Carolina, particularly in cooperative service territories outside major metropolitan areas, is contributing meaningfully to the increase relative to last year's forecast.

- Anna asked a series of clarifying questions about the Central’s forecast. Carl indicated that econometric growth is not applied to large loads at Central, and that the linear increase in later years is driven primarily by residential and large commercial customers rather than industrial expansion. He confirmed that a signed service agreement is the threshold for including large loads in the near-term forecast, as used by both Santee Cooper and Central.

- Anna further asked about the nature of agreements, noting that service agreements in some IRP contexts lack meaningful contractual terms such as exit fees, minimum bill requirements, or defined contract lengths. Carl acknowledged he does not have visibility into the specific terms of contracts between large customers and Central member cooperatives and confirmed that inclusion in the forecast is based solely on Central's representation that a service agreement has been executed.

Carl reviewed the potential large loads forecast, noting that while the aggregate tracked and modeled megawatts remain broadly similar to prior years (5,800 MW tracked and 3,500 MW modeled stochastically) there has been substantial customer turnover since 2024, with only two customers from the prior modeled set remaining. Carl characterized this as a positive indicator of a functioning queue, in which customers either commit to service or withdraw, rather than accumulating indefinitely. What has changed materially is the composition and risk profile of the remaining customers: the higher-probability customers from prior cycles have largely signed onto the system, leaving a small number of reasonably probable prospects alongside a large number of very large, low-probability customers. The result is a significant risk adjustment, with 5,800 MW tracked narrowing to approximately 400 MW planned for in the model. Non-firm service has been discussed among Santee Cooper, Central member cooperatives, and prospective customers, but no non-firm load is currently included in the potential large-load forecast. That assumption would be revisited if and when those conversations mature.

- Anna asked for clarification on why potential customers might be seeking non-firm service, querying whether it reflects a desire to avoid committing to a defined demand level or a preference for non-firm service more broadly. Carl indicated he had limited insight into those specific conversations.
- Bradley Powell (NUCOR) offered context from his organization's experience. Nucor currently takes non-firm service predominantly and is considering further expansion because their operations, including the ability to curtail load by shutting down furnaces, allows them to be interrupted when system conditions require it.

  Anna confirmed this as her understanding, describing the arrangement as service under an interruptible tariff where the customer agrees to interruption at the utility's discretion but otherwise takes full requirements service, which Bradley echoed.

Carl described the probabilistic large-load forecast results, noting a significant shift in the shape of the outcome distribution compared with prior years. Historically, the distribution approximated a normal curve with a modest right-leaning tail, whereas this year's model produced a pronounced long right tail driven by a large number of very significant but low-probability customers about whom limited information is available, combined with a small cluster of high-probability customers creating a sharp early mode. This was described as an asymmetric risk profile, with tail risk skewed toward under-planning rather than over-planning. In response, Santee Cooper has made the strategic decision to plan for the 75th percentile outcome from the stochastic model rather than the 50th percentile used in prior cycles. Despite that upward shift in planning percentile, the resulting planned large load figure of approximately 400 MW represents a substantial decrease from previous years, as many formerly prospective customers have since signed contracts and moved into the base forecast, leaving a smaller and less certain residual pool.

- Hamilton Davis (Carolinas Clean Energy Business Association) sought clarification on the nature of the tail risk Carl had described, that it refers to the risk of being unable to interconnect and serve prospective future customers, not a reliability of service risk for the existing load on the system. Carl confirmed that representation.

- Findlay asked Carl to clarify the green dotted line on the distribution chart for the potential large loads. Carl explained that the chart displays 2038 non-coincident peak outcomes, with the green dotted line marking the 95th percentile result at approximately 808 MW and the yellow dotted line on the left marking the 5th percentile.
- Eddy questioned whether the distributions of coincident and non-coincident peaks (CP/NCP) for potentially large loads would be materially different, given the concentration of load in large blocks and the influence of interruptible rate structures. Carl explained that non-firm and interruptible loads are treated as a resource in the modeling, not as demand reductions. The NCP-to-CP conversion does not forecast interruption dispatch decisions; instead, it applies a historical "haircut" to approximately 91 percent, reflecting observed performance of large industrial loads at the coincident peak under normal conditions.
- Eddy suggested that structuring new large load additions under interruptible service could reduce tail risk, potentially lowering the move from the 50th to the 75th percentile planning target, and that this might represent a less capital-intensive planning approach than adding capacity to cover low-probability but high-impact load outcomes. Carl expressed uncertainty with that framing.

  Will clarified the resource accounting treatment: if a customer signs under an interruptible rate, that contracted interruptible load is modeled as a capacity resource, reflected in reserve margin calculations and would not drive incremental capacity additions like firm load. The modeled interruptible contribution is not the full contracted amount but rather the expected dispatch available at peak, consistent with Carl's description of the 91 percent load factor applied in the NCP-to-CP conversion. Will confirmed that the shift from the 50th to 75th percentile is not primarily a function of the NCP/CP differential; the coincident peak distribution would shift slightly left relative to the NCP distribution, without substantially changing the planning conclusion.
- Chelsea Hotaling (Energy Futures Group on behalf of SELC, CCL) asked whether the low load forecast scenario would apply a different percentile assumption for potential large loads or exclude them altogether. Carl indicated that final low-case assumptions have not yet been set, but he confirmed that the intent is to use aggressive bookend assumptions in both the high and low cases. He noted that the low case has historically modeled not merely the absence of new large load additions but a net decrease in large load customers across the board, and that approach is expected to continue. Will offered to post the finalized high and low load forecast assumptions to the working group webpage once they are ready, which he expected would be one to two weeks.

Carl explained the potential large load forecast's trajectory, noting that nearly 600 MW of the original 1,000 MW forecasted for 2024 has already signed onto the system. He considered this conversion rate as validation of the forecasting methodology's effectiveness in anticipating and accommodating large load additions. Although the current forecast shows a slight decrease in total projected load compared to the 2024 baseline, Carl emphasized that Santee Cooper has effectively planned and absorbed new large loads.

- Eddy asked whether the four forecast bars shown on the comparison slide each represented a different terminal year. Carl and Stewart confirmed that all four bars reflect the same terminal year of 2040, allowing for a direct comparison of how changes to forecast methodology across successive IRP cycles have affected the projected end-of-period large load outcome.
- Anna asked whether the large load comparison chart would look materially different if presented for 2030 rather than 2040, noting that a load ramp extending all the way to 2040 is unusual, given that new large loads typically materialize within a two to three-year window. Carl acknowledged the observation and explained that the terminal year of 2040 was selected precisely because the 2030 to 2040 period is where the greatest uncertainty in the potential large load model resides. He indicated that a 2030 snapshot would show a somewhat lower signed load total than the 586 MW reflected at

the terminal year, but not substantially so, as most anticipated loads are expected to materialize by the early 2030s. Carl confirmed Anna's account that near-term loads are relatively certain while the larger question marks sit further out in the forecast horizon.

Carl presented the consolidated total load forecast, noting that near-term demand slightly exceeds the 2025 IRP winter coincident peak baseline, driven primarily by the industrial customer expansion and stronger near-term growth in the Central's forecast. That relationship reverses by the early to mid-2030s, at which point the significantly reduced potential large-load forecast, relative to prior years, produces a persistent downward divergence from the 2025 IRP Update baseline that persists through the remainder of the planning horizon. Carl also noted that municipal and off-system sales, shown in a light-yellow band, are modeled under the continuing assumption that off-system customers will roll off the forecast at contract expiration, consistent with prior IRP methodology. These loads represent a modest near-term contribution that diminishes to a small residual after 2030.

- Eddy observed that per-household residential energy usage had been projected to decline in successive IRPs - first at around 0.04 percent per year, then more slowly at 0.02 percent - and questioned what is driving the apparent flattening of that trend in the current forecast, particularly given that expanding natural gas availability and reduced EV uptake would both tend to push average household usage downward. Carl clarified that the forecast does still reflect a modest negative trend in per-household usage, with the decline steepening somewhat in the later years. He attributed the near-term flattening to a combination of factors: a reversal of the long-term erosion of all-electric market share that occurred around 2020-2021, followed by a period of strong all-electric household formation in the early post-pandemic years, which has skewed the recent baseline upward. The anticipated expansion of Dominion's natural gas distribution network is expected to gradually resume the erosion of all-electric penetration but given the volume of all-electric growth over the past five years, that effect is not expected to be material until the later portion of the forecast horizon.
- Eddy also raised the potential impact of appliance efficiency standards, including the transition to higher-SEER air conditioning units beginning around 2022 and heat pump water heater requirements expected to take effect in the early 2030s, as factors that could significantly reduce household electricity consumption over the planning period. Carl confirmed that the EIA (US Energy Information) Annual Energy Outlook, which serves as the basis for GDS's household usage estimates, is the vehicle through which those regulatory effects are captured in the forecast, with regionalized AEO data used rather than a post-modeling adjustment.

2026 Integration Study Update
– Joel Dison, Project Lead, PowerGEM

Joel Dison presented results from the 2026 solar integration study conducted using the SERVM model (Strategic Energy & Risk Valuation Model), briefly recapping the three-metric framework introduced at the prior stakeholder meeting. The traditional metric for flex violations, expressed in days per year and analogous to a loss-of-load expectation calculation, is retained from the prior study. Two additional metrics were incorporated: total flex violations as a raw count, and the CPS1 (Control Performance Standard) Stress Index, a new measure introduced for this cycle. Joel explained the CPS1 Stress Index methodology, where for each five-minute interval in which a shortfall occurs, the model calculates an Area Control Error (ACE) deviation (alpha), computes a stress contribution factor (rho) as alpha squared divided by ten times the system frequency bias (beta), multiplies by five to obtain the interval stress contribution, and sums across all 8,760 hours to produce a simulation-level stress index. A study-wide weighted average across all simulations then yields the final CPS1 Stress Index value.

Joel described the benchmark study design, which uses a 2030 study year consistent with the reserve margin study but begins with a no-solar, no-battery portfolio. Batteries are excluded because they count toward operating reserves even when not actively dispatched, which tends to overstate realized reserves and obscures the true incremental operating reserve requirement attributable to solar additions. The benchmark metrics, calibrated to 2021 operating reserve levels, define targets against which each successive solar tranche is evaluated. Results below the benchmark targets indicate system headroom, while results above indicate reserves required to restore the system to its baseline state. Joel noted that the 2021 calibration year produced a higher realized operating reserve level than the prior study's benchmark, with implications to be shown in subsequent slides. He also noted that while solar is not present overnight, targeted operating reserves are applied across all hours to achieve the correct model behavior, with results ultimately reported as incremental realized operating reserves during solar hours.

- Hamilton asked Joel to explain why BESS (Battery Energy Storage System) was excluded from the benchmark study. Joel explained that battery storage counts towards available operating reserves in the model, regardless of whether it is actively dispatching. Its inclusion tends to overstate realized reserves and mask the true incremental operating reserve requirement attributable to solar. The study aims to isolate the additional operating reserves needed to integrate moment-to-moment solar fluctuations. With batteries in the model, the result often indicates no additional reserves are needed, since they passively cover the requirement. When batteries are included for higher solar tranches, their presence inflates the realized reserve figure accordingly. Hamilton confirmed his understanding that, when assigning a cost to the incremental operating reserves identified by the study, BESS resources on the system would be credited in the same manner as thermal resources such as combustion turbines or combined-cycle units.
- Anna asked what the calibration to 2021 operating reserve levels involved, and whether it implies an adjustment to the thermal resource mix to serve the 2030 load. Joel clarified that the resource mix and load remain set to 2030 conditions; the calibration applies only to ancillary services targets. The purpose is to ensure that the no-solar, no-battery 2030 benchmark scenario produces realized operating reserves consistent with what Santee Cooper would experience on a system genuinely free of solar and storage. Using 2021 closely approximates such a system. Load-following targets are then adjusted in the benchmark so that realized reserves match that 2021 reference condition, establishing a clean baseline against which incremental solar tranches can be evaluated.
- Jonathan Ly (J. Pollock, Inc.) noted that prior integration studies had produced a final cost figure for incremental solar reserves and asked whether the current study has moved away from that output toward the CPS1 Stress Index as the primary result. Joel confirmed that the prior study did calculate a cost for incremental operating reserves, whereas the current study determines the quantity of operating reserves required without monetizing it. Will noted that the application of these results in the EnCompass modeling runs would be addressed in the afternoon assumptions discussion, with a different approach from the prior study, where integration cost was applied during the optimization phase but not during production cost modeling. As to what motivated the shift to the CPS1 Stress Index as the central metric, Joel explained that the index represents a methodological refinement to better capture the challenges that renewable resource volatility poses for operators in meeting NERC CPS1 requirements. It’s not a direct replication of CPS1, but an approach that pursues the same objectives by measuring the difficulty of integrating variable resources, reflecting both the frequency and the magnitude of ACE deviations.

  Will provided operational context from on observations of solar integration at Santee Cooper's Energy Control Center. He noted the volatility of solar resources presents real-time management demands for a system characterized by large, relatively inflexible generating units. He emphasized that batteries are the best resource to address that volatility, and that the integration study provides the information needed to plan for what operators require. Will highlighted the key planning improvement offered by the CPS1 Stress Index over traditional flex violation metrics: it captures the magnitude of violations, allowing larger and more operationally difficult deviations to be weighted accordingly. Joel affirmed that point, noting it was covered in the prior working group session and that the magnitude-sensitive nature of the index will be visible in the results, where higher solar penetration levels produce larger deviations that are progressively more difficult to recover from.

- Hamilton asked why BESS behaves differently from a combustion turbine in the model with respect to operating reserves. Joel explained that unlike a combustion turbine (CT) or reciprocating engine, which must be online or ramping to contribute, a battery can transition from zero to full output nearly instantly, meaning its entire capacity is available as load following at all times, provided it has stored energy. This characteristic distorts the benchmark because the model reports the battery's full capability as realized operating reserves simply by being present in the portfolio, regardless of its need. Stewart summarized the logic: removing the batteries stress-tests the system to reveal the true reserve requirement, after which batteries can be reintroduced to confirm they can meet that requirement, enabling more appropriate sizing. Had the batteries remained in the model, they would have implicitly solved the problem, obscuring the underlying need.
- Hamilton also asked about Santee Cooper ‘s experience with neighboring utilities with higher solar penetration, noting Duke Energy Progress, at roughly 20 percent of peak load in installed solar, which has undergone a technical review of its integration methodologies and system operations with Department of Energy (DOE) National Labs and The Brattle Group. He asked whether that work is being used to benchmark Santee Cooper's approach. Will indicated he was not familiar with those materials and welcomed Hamilton's offer to share the technical review documents. He noted that Santee Cooper's operators are in regularly contact their counterparts at other utilities and consistently hear that batteries are highly effective at supplying operating reserves in real-time solar integration, with the first tranche of battery capacity being used primarily for that purpose.
- Eddy inquired about Santee Cooper use of PowerGEM’s modeling for its day-ahead or real-time dispatch, and if the planning model and operational tools solve the dispatch problem. Joel confirmed the fundamental difference between the two environments: the SERVM planning model cannot replicate CPS1 directly, leading the team to progressively refine its proxy metrics from flex violations toward the CPS1 Stress Index. A key limitation is temporal resolution as the planning model operates at five-minute intervals, while real-time operators respond to system deviations every six seconds, a granularity that cannot be replicated in a long-term planning model. Will added that Santee Cooper uses PCI software for fuel forecasting and market planning, separate from the PowerGEM modeling environment used in the IRP.

Joel reviewed integration study results for solar tranches of 250, 500, 750, 1,000, 1,500, and 2,000 MW, comparing them to no-solar benchmark metrics of 1.42 flex violation days per year, 4.31 total flex events per year, a CPS1 Stress Index of 54, and average realized spin of 517 MW per hour. At 250 MW, all metrics remain at or below benchmark, indicating solar can be absorbed without incremental reserves. At 500 and 750 MW, the traditional flex metrics remain close to benchmark, while the CPS1 Stress Index begins to diverge, reflecting its sensitivity to the growing ACE deviations despite similar frequency. Joel explained that geographic diversity partially offsets per-unit volatility as solar penetration increases, but absolute megawatt deviations rise, and the stress index captures that effect where frequency-based metrics do not. The mitigation analysis for each tranche uses graphs of targeted versus realized operating reserves, which remain roughly linear at lower penetrations, indicating the system can still provide reserves when asked. It also shows how each metric responds to added incremental reserves.

At 1,500 and 2,000 MW, the system's ability to provide incremental operating reserves begins to flatten out. The relationship between targeted and realized reserves becomes nonlinear above roughly 400 MW, indicating the dispatchable resource base is tapped out. At 1,500 MW, the traditional flex metrics reach their benchmark targets, but the CPS1 Stress Index levels out around 61, short of the target 54. This suggests that dispatchable thermal resources alone are insufficient. To address this, the 250 MW of battery in the base case portfolio is reintroduced, and an additional 348 MW of targeted operating reserves applied. This yields approximately 330 MW of realized incremental operating reserves during solar hours. At 2,000 MW, batteries are required to meet traditional metrics, and full mitigation to the stress index benchmark requires the 250 MW of battery plus an additional 425 MW of targeted reserves, translating to approximately 353 MW of realized incremental operating reserves. The summary table shows that for tranches up to 1,000 MW, incremental realized reserves under the stress index range from zero to roughly 63 MW. That figure increases to 330 MW at 1,500 MW and to 353 MW at 2,000 MW.

Joel compared the 2026 study results to the prior 2022 integration study, which used a 2029 study year as the closest comparable. The prior study's benchmark realized operating reserves averaged at 379 MW per hour, while the current study's benchmark, calibrated to 2021 actual 10-minute operating reserves, produced approximately 517-518 MW. The prior study's incremental resource was a large, combined cycle with a high 10-minute ramp rate, yielding 1,076 MW of maximum 10-minute regulation-up capability. The current study's system has approximately 712 MW of equivalent capability, reflecting a less flexible resource mix. When comparing equivalent metrics, the current study shows higher incremental reserve requirements at every tranche, consistent with reduced system flexibility. The CPS1 Stress Index produces substantially higher reserve requirements than the traditional flex metric at all penetration levels. At 1,000 MW the difference is 63 MW; at 1,500 MW it is 330 MW; and at 2,000 MW it is 353 MW. Joel presented incremental realized operating reserves broken out by month, for solar hours only, under the stress index results, showing modest seasonal variation across tranches but a pronounced step increase between the 1,000 and 1,500 MW levels. These results were discussed later in the context of EnCompass portfolio modeling runs.

- Anna raised a methodological question about using flexibility metrics as a proxy for CPS1 compliance. She noted utilities have multiple tools beyond operating reserves, such as Automatic Generation Control (AGC) for solar generators and re-dispatching existing units to manage ACE and meet NERC standards. She acknowledged that the model appears to allow any thermal generator to provide operating reserves but questioned the characterization of the CPS1 Stress Index as proportional to CPS1 given the five-minute modeling resolution differs from the timeframe for CPS1 violations. Joel explained that increasing targeted operating reserves in the model causes units to redispatch. Without that increase, the model commits and dispatches only to the required level, and unexpected renewable output deviations produce flex violations analogous to real-world ACE accumulation. He acknowledged that the metric is not a direct replication of CPS1 but is proportional on a comparative basis, as it accounts for both the frequency and magnitude of deviations. PowerGEM has prepared a paper for Santee Cooper documenting the mathematical basis for that proportionality. Joel would need to be consult with Santee Cooper before being made available to the group.
- Anna then asked whether AGC applied to solar could be modeled in EnCompass to meet the operating reserve requirement at higher solar penetration, rather than relying solely on physical generating resources. The exchange clarified that the flex violations identified in the model predominantly reflect sudden drops in solar output, not ramp-ups, so the primary mitigation need is for additional spinning reserves to cover the lost generation, not regulation-down capability. Joel and Will confirmed that pre-curtailing solar to maintain headroom could theoretically provide some buffer, but it would still require spinning backup for the lost output. Bob emphasized that Santee Cooper procures solar through PPA (Power Purchase Agreement) arrangements, so routinely curtailing solar output while continuing to pay for the energy is not currently considered a planning tool. He noted that while inverter controls

and active curtailment through PPA arrangements are being investigated for specific breakdown events, that is distinct from partial curtailment as a systematic operating reserve strategy. Joel added that even if curtailment-based AGC were incorporated into the analysis, it would serve to meet the operating reserve requirement within EnCompass, not to reduce the requirement itself.

Anna countered Bob's economic framing, suggesting that, given the high capital cost of new generating resources to provide spin, paying for curtailed solar energy might actually be the more cost-effective path at higher penetration levels. Bob acknowledged that the question has not been formally studied and that Anna's point warrants further examination and committed to keeping it on the analytical agenda for future consideration.

- Findlay raised a concern about the representativeness of the 2030 study year, noting that while the two new aeroderivative CTs would be online, the Canadys combined cycle (CC) would not, until approximately 2033, and the large coal units would not yet be retired. He noted adding a modern flexible combined cycle typically reduces renewable integration costs substantially and expressed concern that applying integration reserve requirements derived from a 2030 study year could overstate costs for periods after 2033 when Santee Cooper will have more flexible capacity. Will reframed the question for Joel: how would a different resource mix affect the realized operating reserve requirements identified in the study? Joel confirmed substituting the Canadys CC for the coal units produced metrics that fell below the benchmark indicating that Canadys alone would meet all incremental operating reserve requirements identified at any solar tranche level.

  Bob clarified how the integration study results will be applied in the EnCompass capacity expansion model. Rather than applying a cost adder, the 2026 IRP will model an explicit incremental operating reserve requirement for solar installations above a defined threshold. This requirement will be treated as an additional system obligation alongside load and reserve margin targets, met by any resource on the system, not just Canadys. Bob emphasized that the incremental operating reserve obligation may have limited cost impact in practice, because the portfolios that naturally emerge from IRP optimization tend to include flexible resources for economic reasons, which can also satisfy the incremental reserve requirement.

  Findlay acknowledged Bob's explanation but noted that the higher solar tranches of 1,000 to 2,000 MW are unlikely to be online before Canadys, so the 2030 study year may be more relevant to near-term solar procurement than the higher-penetration scenarios. He indicated he would leave the point for further consideration as the IRP modeling progresses. Will noted that by then, the system will also have about 450 MW of battery storage.

- Extending Findlay's earlier question, Hamilton asked whether running the same integration analysis on a 2035 system with Canadys online and coal retired would show that the system can meet the 2030-derived reserve requirements, or if it would actually produce a different, and possibly lower, reserve requirement. Joel explained that a more flexible base case system would yield a lower no-solar benchmark, making it harder to reach. He believes the incremental operating reserves required to integrate a solar tranche would be similar across study years, because the lower benchmark offsets the system’s flexibility.

  Hamilton questioned the appropriateness of the 2021 benchmark, whether it reflects a genuine operating reserve tied to NERC CPS1 compliance requirements, or if it includes headroom that makes the targets more conservative than NERC standards require. Joel explained that 2021 was selected as the closest year to a no-solar, no-battery condition with available 10-minute operating reserve data, in a year that Santee Cooper met its CPS1 obligations. The benchmark is intended to be consistent with the utility's standard operating practice relative to CPS1, not directly derived from NERC requirements, since CPS1 cannot be modeled explicitly. Will acknowledged that questions about how

Santee Cooper's actual CPS1 headroom relates to the benchmark would require input from the utility's operations staff and noted the question for follow-up.

- Hamilton then asked how the incremental operating reserve requirements would be applied in EnCompass; specifically, would it be a dynamic application, varying with solar output across hours and seasons, or a static overlay across all solar hours. Will explained that EnCompass modeling constraints limit the precision available, particularly in the optimization phase. The current plan is to apply no incremental operating reserve requirement below approximately 1,250 MW of installed solar, and above that threshold, to impose a requirement only during solar-online hours, expressed as a percentage of solar output at each hour of approximately 20 percent, or slightly less. In the production cost phase, the team intends to apply reserves on a more manual basis tied to installed solar by year, to better reflect the study results given the same input constraints. Will noted that the approach is still being tested and that by the time higher solar penetrations materialize in the modeled portfolios, the system will likely have sufficient flexible resources to make any incremental cost impact relatively modest.

  Hamilton observed that the hourly variation in reserve holding costs becomes most material during the production cost phase. A 10 AM reserve obligation differs from a 2 PM obligation on a high-solar day, and hourly cost differences could be significant at higher penetration levels. Joel confirmed that PowerGEM provided hourly-resolution reserve data to Santee Cooper. Bob clarified that the reserve requirement in the production cost simulation is tied to actual simulated solar output on an hourly basis, proportionally higher during morning and evening ramp periods when output uncertainty is greatest. Bob concluded that this implementation approach is expected to produce lower incremental integration cost impacts than the prior IRP cycle.

2026 Triennial IRP
- Will Brown, Manager, Resource Planning, Santee Cooper
- Bob Davis, Executive Consultant, nFront Consulting

Will opened by recalling that the methodological approach had been previewed at the prior meeting and that heavy modeling work is expected to begin within the next few weeks. A deadline of the end of the day, June 17th, was set for stakeholder feedback on assumptions. Financial assumptions remained largely unchanged from the prior year. On Demand Side Management (DSM), Will confirmed that the Energy Efficiency (EE) and Demand Response (DR) levels used in the IRP reflect the market potential study results developed with Steven Royce and Jim Herndon, and that conservation voltage reduction, previously modeled as a discrete 20 MW dispatchable resource, is now implicit in the load forecast. DSM assumptions cover only directly served Santee Cooper load, with Central's DSM capability captured within Central's load forecast contribution. Reserve margin assumptions follow the 2026 reserve margin study results: 20 percent winter and 18 percent summer, with Carolina Reserve Share Group obligations modeled for 2027 through 2029 split evenly between spin and non-spin. Will noted that solar integration operating reserves are incremental to the Reserve Share Group obligations.

Bob reviewed the fuel price forecast methodology. Natural gas pricing uses the EIA Annual Energy Outlook as the basis for medium, low, and high cases, blending NYMEX Henry Hub prices for 2026 through 2028 to reflect near-term market conditions before reverting to the AEO trajectory. Delivered gas prices incorporate hub pricing for Zone 4, Zone 5, and Columbia Gas Mainline; the latter relevant to modeling receipt point gas for the Winyah combined cycle being jointly developed with Dominion. Pipeline tariff charges are pancaked as appropriate. On an all-in basis, average gas prices across the 2026-2055 study period are approximately 1% higher than modeled in the prior IRP, with higher near-term and lower long-term values. Coal prices are also derived from the AEO, using the reference, high oil and gas supply, and low oil and gas supply cases for consistency with the gas forecast sensitivities. Mine-mouth prices for Illinois Basin, Central Appalachia, and Northern Appalachia are adjusted for Santee Cooper's rail transportation contracts, source blending, and fuel handling costs. Average coal prices are approximately 12 percent lower than those used in the prior IRP. For CO2 pricing, the Interagency Working Group social cost of greenhouse gas forecast continues to be used for sensitivity cases, with the start year for applying CO2 costs shifted from 2028 to 2032, reflecting the current federal regulatory environment and the likely lead time before any new carbon regulation would take effect.

Will presented the existing fleet with winter capacity ratings to be used in the model, noting no material changes from prior cycles. Signed PPAs and Central's Non-Shared Resource (NSR) resources are included as pooled system resources. Signed PPAs four through seven are new additions not previously shown to the working group. Contracted solar will reach approximately 750 MW and contracted battery storage approximately 450 MW in the near term through PPA arrangements. Committed resources assumed across all portfolios include Rainey station upgrades, Santee Cooper's share of the jointly developed Canadys combined cycle with Dominion, modeled consistent with the siting application, and LMs additions at Winyah - all presented as incremental to the existing fleet ratings. Committed retirements across all portfolios include Winyah at the end of 2034 and the Myrtle Beach and Hilton Head combustion turbines at the end of 2033, consistent with the 2023 and 2025 IRP assumptions.

- Eddy asked why Winyah's retirement is modeled at end of 2034 rather than earlier, given that the Canadys combined cycle is expected online by 2033 and an earlier retirement might allow lower-cost replacement resources to enter. Will acknowledged the question noting the 2034 date as a modeling simplification, and that practical retirement timing would depend on replacement resources being online and capacity being sufficient to serve load. Bob added that the 2034 date is also constrained by ELG (Effluent Limitation Guidelines) regulatory compliance requirements, which preclude operating Winyah beyond that point without costly zero liquid discharge and additional effluent controls. Bob further noted that prior modeling runs have consistently shown that retiring Winyah earlier and building a replacement asset is generally more expensive or at best cost-neutral, meaning there is no demonstrated economic basis for accelerating the retirement.
- Findlay asked whether the 2026 IRP reflects a staged online date for the Canadys combined cycle, recalling that the 2025 IRP update had shown one unit coming online in 2032 with the remainder following in 2033. Bob confirmed after checking that Findlay's recollection was correct: in the 2025 IRP update, one-third of the Canadys capacity was modeled as available for winter 2032 with the balance online for winter 2033. However, by the time of the certificate of need filing, the assumption had been revised to show no capacity available for winter 2032 and the full resource available for winter 2033. Bob indicated the current slide reflects the assumed reliable planning online date and that any further staging details would be subject to verification.
- Findlay also asked whether the end of 2034 Winyah retirement date is a hard-coded assumption rather than a model-selected outcome. Will confirmed that Santee Cooper intends to hard code the retirement, reflecting that the utility has already made the capital investments required to operate Winyah under the 2020 ELG rule through 2034, but is not budgeting for the zero liquid discharge upgrades that would be required to continue operating beyond that date. The Myrtle Beach and Hilton Head combustion turbine retirements are similarly hard coded.

Bob presented the 2026 candidate resource assumptions, covering capital costs, capacity ratings, variable and fixed O&M (operations and maintenance), and heat rates. These assumptions are prepared annually based on Sargent & Lundy market experience and industry sources. Combined cycle options include one-on-

one and two-on-one configurations, with the latter reflecting economies of scale. For peaking resources, the model includes H-class and F-class frame combustion turbines. The F-class unit has slightly less capacity and carries higher per-unit capital, fixed O&M, variable O&M, and heat rate values, but it is selected when adding the larger H-class would result in surplus capacity. Aeroderivative and reciprocating engine units have roughly half the F-class size, higher capital and O&M costs, but better heat rates. Nuclear options include a 300 MW Small Modular Reactor (SMR) and an approximately 1,100 MW AP1000. The AP1000 has a lower per-unit capital cost and could appear in coal retirement sensitivity cases, but it is not expected to be selected in any of the standard portfolio scenarios.

- Eddy inquired into the influence of Santee Cooper's recent CC cost experience on Sargent & Lundy capital cost assumptions. Bob noted that during the 2025 IRP update and certificate of need process, the Dominion-prepared capital and O&M cost estimates for the Canadys joint build were broadly consistent with the Sargent & Lundy generic assumptions. For the 2026 IRP, Sargent & Lundy increased its cost estimates further. Bob explained the changes: frame resource capital costs are up approximately 60 percent, aeroderivative and reciprocating engine costs are up approximately 35%, and nuclear up by approximately 11 percent. The drivers cited by Sargent & Lundy include increased vendor quotes, heightened demand for these resource types driven by data center load growth and broader utility sector expansion, and rising Engineer Procure Construct (EPC) contractor costs. The EPC component was most pronounced for more complex frame resources and less significant for modular aeroderivative and reciprocating units, which have shorter balance-of-plant construction timelines.
- Eddy noted that Santee Cooper is likely to receive EPC bids in the near term and asked whether those bids would inform or adjust the modeled cost assumptions, observing that the natural sequencing of these projects creates a lag that makes jurisdiction-specific EPC cost data potentially valuable. Will indicated a preference for maintaining the Sargent & Lundy generic assumptions for IRP purposes, noting that the January 2026 update is believed to have captured much of the recent run-up in costs driven by competition for these resources, and that a line has to be drawn at some point in the assumption-setting process. Will also noted that a solar solicitation is underway with bids expected shortly.
- Will and Chelsea noted that the planned 50 percent thermal capital cost sensitivity provides a safeguard against the possibility that current generic assumptions understate actual costs. Will confirmed for Chelsea that this sensitivity would be included in the 2026 IRP modeling, consistent with the previous IRP cycles.
- Anthony Sandonato (J. Kennedy & Associates on behalf of ORS) echoed Eddy's point on capital cost comparability, asking how the Summer nuclear project, that could have 500 MW of capacity, is being factored into the 2026 IRP. Will acknowledged that the resource planning team has limited visibility into the Fairfield project negotiations, with most decision points expected after the September IRP filing. The intent is to acknowledge the project's existence in the IRP narrative but not model it as a committed resource due to the lack of firm assumptions. Will noted any material developments occur during the 300-day proceeding would need to be addressed at the May hearing. Bob added that treating the capacity as a foregone conclusion could risk under-planning for future requirements and suggested a qualitative discussion in the IRP, indicating that the project could reduce or eliminate the need for certain resources, rather than embedding it as a planning assumption.
- Eddy challenged the framing that the Fairfield Nuclear Project cannot be included in the IRP until its parameters are fully known, arguing that the purpose of a planning process is precisely to evaluate reasonably foreseeable scenarios, including uncertain, not just previously made decisions. He noted that public statements suggest the project is being actively pursued and excluding it from the IRP while

modeling hypothetical resources appeared inconsistent with the intent of the planning exercise. Will acknowledged the point, agreeing that more is known about the Fairfield project than about many generic resources modeled in the IRP. He did not commit to include it in the base portfolios, citing the risk of under-planning if the project does not materialize on the assumed timeline.

Will drew parallels to Duke Energy's experience of having to refile an IRP mid-proceeding due to unanticipated load growth, as well as Santee Cooper's 2023 supplemental IRP filing when Central NSR clarity emerged. He committed to going beyond a qualitative mention and developing a more substantive sensitivity, potentially quantitative, to explore how the Fairfield Nuclear Project could affect portfolio selection, building on what has already been filed publicly on the subject.

- Findlay noted that no one had suggested including the Fairfield Nuclear Project in the base portfolios. He recalled the idea of running a Fairfield sensitivity had already been raised during the coal retirement technical discussions, specifically to examine whether the project could support Cross retirement scenarios. He reinforced Eddy's view that a comprehensive triennial IRP, should reflect multiple plausible futures, and a Fairfield side case was a reasonable analytical step. Will clarified the modeling hierarchy: base portfolios, sensitivities, and side cases are treated as distinct categories and indicated a side case examining what the portfolio would look like if Fairfield materialized, analogous to the higher thermal capital cost side case could be useful.

Bob presented the renewable and storage resource assumptions for the 2026 IRP, noting a change in presentation format. Rather than leading with levelized cost of energy and capacity PPA pricing, capital costs and fixed O&M are shown directly to easier comparison with thermal resource assumptions. Capital cost estimates are based on Sargent & Lundy projections for Santee Cooper, with solar and battery costs about 20-30 percent higher than prior IRP assumptions and wind approximately 10-12 percent higher. The 2024 Annual Technology Baseline (ATB) continues to be used for the cost trajectory curve, updated to a 2026 base year. PPA pricing methodology is unchanged, using SNL capital and fixed O&M inputs, ATB conservative case cost trajectories, and ATB moderate case production parameters. Developer financing is based on ATB assumptions updated for current interest and financing rate conditions. Asset life expectancies are 30 years for solar and wind and 20 years for batteries. On tax credits, solar and wind are assumed to receive no investment tax credits (ITCs) following the changes enacted through the One Big Beautiful Bill. Batteries are assumed to receive a 40 percent investment tax credit, reflecting energy community bonus credits for all modeled battery resources, a change from the prior IRP based on stakeholder feedback. The phase-out schedule is shifted two years later than the statutory dates to reflect a safe harbor assumption for beginning-of-construction timing.

- Chelsea asked about the source of the long-duration storage cost assumptions, which Bob confirmed are Sargent & Lundy. She noted that the capital and fixed O&M costs appear to be double-counted for 100-hour Form Energy batteries in other utility IRPs, citing some utilities' participation in Form's early projects or use of Form's published cost estimates, and noting that at least one IRP had received a bid for a 100-hour battery. Chelsea offered to share links to those IRP filings for reference. Bob acknowledged the methodological difficulty of directly borrowing cost data from a leading-edge technology vendor and indicated he would ask Sargent & Lundy to review and, if appropriate, adjust the long-duration storage assumptions in light of Chelsea's feedback.
- Hamilton asked whether the IRP assumptions account for safe harboring of solar PV (photovoltaic) and the potential to bring assets into service by 2030 to capture available PTCs (production tax credits) or ITCs under current tax rules. Bob explained that no such assumption has been made, as Santee Cooper's procurement is proceeding through a separate RFP process and the IRP does not assume any new solar or wind assets would be contracted, developed, and online by 2030. Hamilton acknowledged the point but flagged that a meaningful volume of capacity in the current RFP pipeline

likely already has interconnection agreements and may be eligible for tax credits and wanted to ensure there was no tension between the IRP modeling assumptions and decisions being made in the separate procurement process. Bob confirmed there is no such tension: any tax credits embedded in RFP pricing would be reflected in whatever contracts Santee Cooper ultimately executes, independent of IRP assumptions. Bob also noted that the RFP process is unlikely to be far enough along to benchmark or inform IRP assumptions before the modeling is finalized, though internal comparisons would still be made for reference.

Will presented the first year-available assumptions for candidate resources, developed in consultation with internal subject-matter experts and consultants. The framing premise is that if Santee Cooper were to make a procurement or build decision at the time of IRP filing in September, the first year-available date reflects how long it would take to bring each resource type online in time for a winter peak. The resulting lead times by resource type are solar, batteries, aeroderivative and reciprocating engines (4 years); onshore wind (7 years); combined cycles and combustion turbines (8 years); long-duration storage (ten years); and offshore wind, small modular reactors, and large nuclear (thirteen or more years).

- Anthony asked about the 2026 IRP's retention of the 2025 update's constraint requiring a combined cycle to be selected before a frame combustion turbine. Will confirmed the constraint, explaining that Santee Cooper lacks sufficient gas infrastructure for a large-frame CT on interruptible service without firm transmission from a combined-cycle project. Bob clarified that the constraint applies only to large frame CTs; aeroderivative and reciprocating engine units can be selected before a combined cycle, given their smaller scale and modular nature.
- Eddy asked about the 10-year assumption for long-duration storage first-year availability, curious if it reflects technology availability concerns or typical project development timelines. Will explained that the assumption embeds a four-to-five-year South Carolina pilot phase, followed by a similar full-scale development period, given the modeled resource. He acknowledged the uncertainty and invited stakeholder feedback, indicating he would be open to revising the lead time if supporting evidence for a shorter timeline could be provided.

Bob presented the effective load-carrying capability (ELCC) assumptions for the 2026 IRP, noting these were previously reviewed with Joel in an earlier stakeholder session and are documented here for reference. Single-technology winter ELCC curves are used as the base, with summer curves and synergistic effects between solar and battery also considered. Solar carries a winter ELCC of approximately 4 percent. Four-hour batteries start above 90 percent at low installed capacity and decline to the 40-50 percent range at approximately 2,000 MW of nameplate capacity. Eight-hour battery curves are higher throughout. Onshore wind starts at roughly 55 percent and falls below 20 percent at 2,000 MW of installed capacity. Offshore wind, benefiting from more consistent output profiles, starts near 80 percent and declines to approximately 50 percent at high penetration levels.

Will outlined the 2026 IRP portfolio structure, mirroring the 2023 IRP and subsequent updates. The portfolio includes a base case, a renewable and storage portfolio (renamed from the prior "no new fossil" to be more descriptive and forward-looking), a coal retirement portfolio, and a net zero portfolio. Statutorily required portfolios include retirement of Winyah by 2028 and a net-zero scenario. Sensitivities will be run on all base portfolios, including high- and low-load cases, to re-optimize resource builds and fuel and CO_2 price sensitivities to evaluate the NPV impacts of adjusted prices.

- Anthony asked whether the Cross retirement date will be determined through the coal retirement analysis and then held fixed across all IRP portfolios. Will clarified that the approach is more flexible: the base portfolio may or may not include a retirement depending on modeling results, while the coal retirement and net zero portfolios could use different retirement dates selected to best reflect each scenario and ensure meaningful comparison across portfolios. The coal retirement analysis, running full and partial retirement cases at five-year intervals from 2035 through 2050, aims to identify the optimal retirement date for each portfolio context while maintaining consistent metric comparisons.

Will covered the remaining IRP assumptions and modeling parameters. The final rule on greenhouse gas (GHG) regulation is expected to be published within weeks. Based on current understanding, it will remove retirement requirements for existing coal units while retaining emissions standards for new combined cycles and combustion turbines. Santee Cooper will review the final rule upon publication and ensure all portfolios, including the Canadys unit, comply with requirements. Coal retirement scenarios will include transmission upgrade costs, and new combined-cycle additions will incorporate firm natural-gas transmission pricing. Renewable build rate limits will remain at 300 MW per year for solar and 100 MW per year for onshore wind, subject to adjustment during testing. Solar integration operating reserves will be modeled as previously discussed. On side cases and sensitivities, Will confirmed plans to run low, medium, and high DSM cases, a 50 percent thermal capital cost escalation side case, and a Fairfield Nuclear Project side case (added in response to the earlier discussion). The IRP metrics framework will be consistent with the 2023 IRP, with the addition of a new reliability verification metric derived from SERVM. All portfolios will be run through SERVM, capacity will be added as needed to meet reliability targets, and the resulting reliability metrics will be reported alongside the standard portfolio comparison outputs.

EnCompass Benchmarking Results
- Will Brown, Manager Resource Planning, Santee Cooper
- Matt Eckhart, Senior Consultant, nFront Consulting

Will introduced the EnCompass benchmarking exercise as a best practice for triennial IRP cycles to verify that the base model's replication of actual system dispatch before forward-looking modeling. He noted reviewing Dominion's benchmarking approach and results and structuring the presentation format to be consistent with what working group members familiar with Dominion's stakeholder process would recognize.

Matthew explained the benchmarking study's purpose as evaluating the EnCompass model performance relative to actual historical resource dispatch. The benchmarking model differs from the IRP model in four key ways: load data shifts from forecasted monthly energy and demands to actual 2025 hourly load data; fuel pricing shifts from monthly forecasts to natural gas day-ahead spot prices and monthly delivered coal prices; resource operation modeling shifts from assumed forced outage records; and economy transactions (market purchases and sales) are incorporated to capture their effect on the generation resources dispatch.

- Anna inquired about the benchmarking model inputs. On natural gas pricing, she queried whether Santee Cooper exclusively procures gas on a spot basis. Bob clarified that Santee Cooper sources gas through multiple channels, including aftermarket transactions, but that spot prices are used as the basis for dispatch decisions, representing the marginal cost of gas on the system. On load data, Anna asked if interruptible and non-firm industrial customers had been removed from the model since actual 2025 hourly loads were used. Matthew indicated that interruptible DR resources were not removed from the model, but that their dispatch in the benchmarking output was minimal. A check for non-firm load curtailment showed no such events occurred during the period.

Matthew presented benchmarking results showing that the EnCompass model dispatch closely aligns with actual 2025 generation performance for most resources. Most units are within ±1 % of actual output as a share of total generation. The primary variation involves a swap between Winyah and the Rainey combined cycle and combustion turbine. Winyah runs somewhat higher in the benchmarking model, while Rainey runs lower relative to actual operations. Matthew and Bob attributed this to a fidelity difference in capacity ratings. The benchmarking model uses net dependable capacity on a seasonal basis, while actual system operators can push units above those ratings in favorable conditions, capturing real-time capability that the model does not fully replicate. Matthew concluded that the benchmarking results validate the EnCompass model's production cost performance, confirming its appropriateness for use in the 2026 IRP resource planning process.

Working Group Feedback
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart opened the working group feedback session, inviting candid input for Santee Cooper and Vanry on the IRP process and the meeting facilitation. He framed the session around the group's founding mission and objectives: providing a wide range of perspectives and expertise to inform IRP development in the best interest of Santee Cooper's customers and the state of South Carolina; creating open dialogue and a forum for diverse opinions; enabling deep technical discussion of assumptions, methodologies, portfolios, and sensitivities; and fostering collaboration on how diverse perspectives could benefit the IRP process. Participants were invited to assess the group's progress in meeting these objectives.

- Anna provided valuable feedback on the working group process, highlighting three strengths. She praised Santee Cooper's genuine openness to stakeholder input, noting it as authentic rather than performative. She also commended the proactive communication of planned methodological changes ahead of each IRP cycle, recognizing this as essential since only Santee Cooper has full visibility into the changes. Anna emphasized the value of having the consultants and staff present for direct technical dialogue, contrasting this with other stakeholder processes where engagement is filtered through a facilitator with limited involvement in the analysis. Anna also noted a limitation in the data sharing process as underlying data and modeling details are not accessible until formal discovery during the IRP proceeding, which is less transparent than other stakeholder processes she participates in. She did acknowledge that the group does receive good qualitative context on trade-offs and considerations.
- Eddy supported Anna's comments and added contrasted them with a different stakeholder process He cited his participation in Dominion's working group had been used against his organization in litigation, with attendance at meetings implying implicit acceptance of positions not formally challenged. He offered that situation as an example of how a stakeholder process can undermine trust and acknowledged that Santee Cooper's process has not exhibited those tendencies.
- Hamilton echoed Anna and Eddy's positive remarks, describing the process as transparent and collaborative. He noted that questions and concerns raised during sessions receive direct and responsive answers, making it easier to participate constructively in technically complex and lengthy meetings.
- Findlay praised the working group process structure, singling out the dedicated technical sessions, such as the coal retirement deep dives, that enabled meaningful engagement with substantive issues that were not feasible at standard working group meetings. He credited both Santee Cooper and Vanry with effectively applying that structure and characterized the overall meeting design as working well.

Stewart invited feedback on meeting length, frequency, types, or documentation, with no changes requested by the group.

Will asked Anna to elaborate the most useful data to receive before the IRP filing, acknowledging uncertainty about Santee Cooper's abilities to share model data in advance.

- Anna acknowledged the familiar hesitation around sharing draft EnCompass model inputs and results before they are finalized, particularly given the likelihood of litigation in triennial IRP proceedings. She offered three responses: first, that other jurisdictions provide draft models to stakeholders, and offered to connect Santee Cooper with those utilities; second, that earlier model access tends to surface technical and in-the-weeds modeling issues that cannot be raised through the standard stakeholder process and that resolving them pre-filing can reduce litigated issues; and third, drawing an analogy to medical malpractice litigation, that transparency tends to reduce rather than increase adversarial risk by keeping all parties informed and aligned. Anna clarified the concern is not a lack of transparency about what Santee Cooper is doing, but rather that certain granular modeling issues, including on the transmission side, only become apparent when the model is made available at filing. Stewart noted that he had prior experience with a utility that shared models earlier and committed to exploring with Santee Cooper how that approach might be implemented.

Will acknowledged the complexity of the modeling work and the risk of errors in draft materials as factors contributing to the reluctance around early data sharing. He appreciated the group's grace when Santee Cooper or its consultants do not have immediate answers. Stewart observed a meaningful evolution of the working group, with stakeholders now collaborating and framing disagreements as technical questions. He credited the stakeholders for the productive tone of the meetings.

- Anna also suggested that comments submitted by other interveners in the IRP proceeding be made available to working group members, proposing that intervener submissions be posted to the IRP webpage so stakeholders could see the range of perspectives and identify areas of common ground or divergence. Stewart and Will thought this a worthwhile idea and committed to exploring it with the team. Will also noted that a Stakeholder Feedback Forum is already available on the webpage. It was established and used more actively during the 2023 IRP cycle and suggested it could be used to collect and share written comments among participants.

Meeting Closeout
– Stewart Ramsay, Meeting Facilitator, Vanry Associates

Stewart closed the meeting by reviewing the action items and thanked participants for their engagement throughout the day and across the full IRP cycle and expressed particular appreciation for the candid process feedback received.

Commitments and Next Steps

ACTION ITEM – noted during the meeting discussion	By **WHOM**
1. Review planned maintenance costs in years preceding retirement study years to determine potential impacts on retirement decisions related to the Cross Generating Station	Resource Planning
2. Share low and high assumptions for the load forecast and post that information to the IRP website and send to the working group when available	Resource Planning
3. PowerGEM to provide a paper to Santee Cooper, to be shared with the working group explaining the basis on which the CPS1 Stress Index Results are based	Resource Planning
4. PowerGEM and Santee Cooper will consider questions and feedback from the working group on the Solar Integration study including the impacts of the study year, benchmark year, and underlying resource mix	Resource Planning

5.	Send 2026 IRP assumption and modeling approach feedback by end of day June 17	All stakeholders
6.	Provide assumptions for LDES resources, including costs and first year available, from other IRPs	Chelsea Hotaling
7.	Consider a side case for the Fairfield Nuclear Project	Resource Planning
8.	Review with Santee Cooper examples of sharing modeling data earlier	Stewart Ramsay
9.	Review how best to post other intervenor comments for others to reference	Resource Planning & Vanry

Next Steps:

- The next general notice meeting is on June 11, 2026
- The next working group meeting will be on October 7, 2026

APPENDIX A

List of Stakeholder Working Group Members and Attendees

ORGANIZATION	**MEMBER** / ALTERNATE	**June 3rd ATTENDEES**
Office of Regulatory Staff	Findlay Salter Jeffery Gordon Julian McElhaney **Shane Hyatt**	Findlay Salter Jeffrey Gordon Julian McElhaney
SC Dept of Consumer Affairs	**Jake Edwards** Roger Hall	Jake Edwards
SC Dept of Natural Resources	Elizabeth Miller **Lorianne Riggin**	Elizabeth Miller
SC Dept of Environmental Services	**Rhonda Thompson** Marie Brown	Marie Brown
Central	**Caleb Bryant** Leslie Maley	
J. Pollock	Jeffry C. Pollock **Jonathan Ly**	Jonathan Ly
Century Aluminum	**Michael Early**	
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**	
Individual	**Richard Berry**	
Individual	**Diane Bell**	
Individual	**Dennis Boyd**	
Carolinas Clean Energy Business Association	Hamilton Davis **John Burns**	Hamilton Davis
Conservation Voters of South Carolina	Erin Siebert **Jalen Brooks-Knepfle** John Brooker	Jalen Brooks-Knepfle
Coastal Conservation League	Kennedy Bennett **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	Anna Sommer Chelsea Hotaling
Sierra Club	**David Rogers** Dori Jaffe Mikaela Curry Sari Amiel	
Vote Solar	**Jake Duncan**	Jake Duncan
Southeastern Wind Coalition	**Jocelyn Juliano**	Jocelyn Juliano
Santee Cooper Resource Planning	Clay Settle **Ellie Galagher** **Will Brown**	Ellie Galagher Will Brown
nFront Consulting	**Bob Davis** Jonathan Nunes	Bob Davis
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

Carolinas Conservation League	Dylan McGuire
Century Aluminum	Annie Saum Michael Rodgers
Central	Christopher Goering Heather Zrust William Potter
J. Kennedy & Associates (ORS)	Leah Wellborn
Office of Regulatory Staff	Anthony Sandonato Braden Relyea