FRCC
Florida Reliability Coordinating Council, Inc.

2022
Ten-Year Site Plan Workshop
FRCC Studies and Reports

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FRCC
2022 Load & Resource Reliability Assessment Report

FRCC-MS-PL-397

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3001 North Rocky Point Drive East, Suite 410
Tampa, Florida 33607-8410
(813) 289-5644 - Phone
(813) 289-5646 - Fax
www.frcc.com

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TITLE	NAME	DATE
Version Author	Andrew Whitley (FPL) Navid Nowakhtar (FMPA) Christina Rau (FRCC)	07/07/2022
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Original Author: Andrew Whitley (FPL), Navid Nowakhtar (FMPA), Christina Rau (FRCC)
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1.0 Purpose

A key responsibility of the Florida Reliability Coordinating Council (FRCC) is to assess the planned reserve margin and resulting reliability of the Bulk Power System in the FRCC Region[1] to ensure resource adequacy as required by the Florida Public Service Commission (FPSC)[2].

As part of this annual assessment, the FRCC aggregates, and reviews forecasted load and resource data and identifies any expected planning reserve or reliability issues over the next ten years. The FRCC receives data annually from its members to develop the Regional Load & Resource Plan (RLRP). Based on the information contained in the RLRP as well as other FRCC reliability assessment processes, this Load & Resource Reliability Assessment Report (Reliability Assessment Report) is developed and submitted to the FPSC along with the RLRP.

The Reliability Assessment Report evaluates the projected reliability for the FRCC Region by analyzing Planned Reserve Margins, Loss of Load Probability (LOLP), Availability Factors (AF), and Forced Outage Rates (FOR). In addition, this report incorporates any potential reliability issues that may be encountered with varying system conditions (off peak) such as solar generation levels in Florida. This assessment may include insight from studies performed by the Resource Subcommittee (RS), Load Forecast Working Group (LFWG), Transmission Technical Subcommittee (TTS), Fuel Reliability Working Group (FRWG) and other operations planning groups.

2.0 Terms and Definitions

Terms are defined within the document.

3.0 Responsibilities

3.1 Resource Subcommittee (RS)

The RS is responsible for reviewing this document.

3.2 Load Forecast Working Group (LFWG)

The LFWG is responsible for reviewing this document.

3.3 Fuel Reliability Working Group (FRWG)

The FRWG is responsible for reviewing this document.

3.4 Transmission Technical Subcommittee (TTS)

The TTS is responsible for reviewing this document.

3.5 Planning Committee (PC)

The PC is responsible for the final approval of this document.

[1] As of January 1, 2022, the FRCC Region includes Gulf Power Company.
[2] FAC 25-6.035: Adequacy of Resources (https://www.flrules.org/gateway/ruleno.asp?id=25-6.035)

4.0 Executive Summary/Conclusion

In summary, the findings of the 2022 Reliability Assessment Report of the FRCC Region are:

- Electric service is projected to be reliable from[3] a resource adequacy perspective throughout the ten-year planning horizon, consistent with the following:
  - Reserve margins, including the use of Demand Side Management (DSM), for the FRCC Region for the summer and winter peak hours are projected to meet or exceed 20% for each year in the ten-year period, which is above the FRCC's minimum Reserve Margin Planning Criterion of 15%.
  - Reserve margin without DSM is declining over time, and this decline is coincident with an increase in intermittent and duration-limited resources. The region is increasingly dependent upon DSM and intermittent/duration-limited resources in the later years of the study period.
  - The results of the most recent (2022) Loss-Of-Load-Probability (LOLP) analysis of the period 2022-2026 reflect the expectation that the FRCC region will not exceed an LOLP level of 0.1 days per year during that timeframe, under the assumption that duration-limited resources perform as modeled under typical meteorological year weather conditions; an LOLP level of 0.1 days per year is commonly used in the power industry as a reliability criterion.
  - Projected low Forced Outage Rate (FOR) and high Availability Factor (AF) are largely due to the utilities' modernization and maintenance efforts.
  - Measuring traditional reserve margins over a seasonal peak hour, while highly beneficial, is anticipated to be subject to reduced applicability in the context of resource adequacy as the amount of intermittent and duration-limited generation synced to the FRCC system increases. Additional adequacy measurements that account for capacity and energy sufficiency across all hours of the day are being reviewed to better capture and communicate the long-term adequacy position of the FRCC as a whole. FRCC Members and staff continue to work on defining and evolving the standard practice for such calculations.
  - Specifically, the FRCC Board has directed the Resource Subcommittee and Load Forecast Working Group to coordinate across a wide range of expertise to better capture risks related to these emerging issues in the future. One current Resource Subcommittee effort is evaluating resource availability across two 24-hour periods around the summer and winter peak to evaluate the potential impacts on system peak hour and energy adequacy in the future as renewable resource installations continue to grow
  - The possibility of extreme weather events, the integration of increasing amounts of renewables and time duration limited storage onto the grid, the impacts of gradual electrification of transportation on future load, as well as the potential for natural gas supply disruptions are emerging issues that are being reviewed in terms of the broader resource adequacy discussions.

3 Effective January 1, 2022, Gulf Power was merged into FPL for ratemaking purposes. All projected information presented for the years 2022 through 2031 is for the single integrated system (FPL), moving Gulf's capacity, demand, and energy into the FRCC section. These transitional impacts have been specifically identified where practical. Historical data prior to 2022 excludes the Gulf system.

- The load forecast that results from the amalgamation of independent, individually derived Member projections is reasonable, and reflects moderate growth over ten years.
  - The average annual growth rate for Net Energy for Load (NEL) is expected to be 0.93% per year, which is higher than the previous forecast.
  - Firm summer peak demand is expected to grow by 1.09% per year, which is lower than the previous forecast.
  - Firm winter peak demand is expected to grow by approximately 1.06% per year, which is lower than the previous forecast.

The following table summarizes additional net Utility-Owned Generation Capacity including additional capacity being added in the Gulf area.

Additional Utility-Owned Generation Capacity (MW)

Combined Cycle	3,400
Combustion Turbine Capacity	2,500
Plant Uprates	500
Plant Retirements	(2,300)
Net Non-Renewable Generation	**4,100**
Firm Solar Capacity	**4,900**
Firm Battery Storage Capacity[4]	**2,400**
Net Total (Summer)	**11,400**

- Natural Gas is expected to remain the primary fuel source for the region with all proposed new thermal generation expected to use natural gas as their primary fuel.
  - Natural gas is projected to provide approximately 65% of the electrical energy (GWh) in peninsular Florida by the end of the ten-year planning horizon. The existing and planned pipeline capacity supporting the Region are adequate to meet projected peak day gas requirements (summer and winter) through 2031, with the assumption that any short-term capacity shortfall can be met with member backup fuel capabilities or market solutions. However, a growth in natural gas use sensitivity scenario indicated some possible additional natural gas pipeline capacity could be needed in the 2031-time frame (by the end of the planning period).
  - In the event of a short-term failure of key elements of natural gas delivery infrastructure, use of dual fuel capability (between 57% – 61% of available natural gas capacity over the planning horizon) will be required to meet projected demand. It should be noted that additional fuel management coordination would also be required in the event of a long-term failure of key elements of natural gas delivery infrastructure.

[4] Limited Duration Energy.

- Renewables in the FRCC Region are expected to grow from:
  - 3,591 MW in 2022 (5.9%) to 7,754 MW in 2031 (11.8%) in terms of nameplate generation capacity and
  - 12,013 GWh in 2022 (4.9%) to 50,547 GWh in 2031 (18.3%) in terms of energy served.

  This growth is projected to come from solar generation. Members continue to leverage operating experience with these resources to better forecast future contributions to capacity, energy and how they impact system peaks. The FRCC will continue to monitor and evaluate the effects of increased penetration levels of renewable generation on the system.

- Battery storage contributions to capacity are included in reserve margins consistent with members' TYSP filings. The region currently has approximately 496 MW of firm summer capacity from battery storage and 2,400 MW of additional firm summer capacity from battery storage facilities are planned through 2031. As FRCC members continue to gain experience with operating battery storage, members will be better able to develop methodologies and protocols to properly account for battery contributions toward capacity, energy sufficiency and operational support.

- COVID-19 and Recent Fuel Price Increase Impact on Load Forecasts
  - Although the amounts vary by member, COVID-19 impacts have gradually receded back to pre-pandemic load levels.
  - The LFWG is actively engaged in monitoring the potential impact of recent high natural gas prices and other geopolitical conditions that have increased inflationary pressures on electric customers. Any price elasticity impact associated with such risks would only improve reliability metrics presented herein, all else equal.

- FRCC members continue to learn from recent electrical system events that have occurred across the Country. Specifically, in 2021, US consumers endured two significant extreme weather events in California and the south-central area of the country which resulted in firm load shedding in order to preserve broader system reliability. The second event stretched over Texas, Arkansas, and Louisiana in February of 2021 and was an historic cold weather event that forced generating units offline, reduced natural gas supplies, and pushed electric heat demand to very high levels. The Texas event resulted in significant societal impacts and an ongoing Regulatory focus on preparations for extreme weather.
  - As a result, NERC and FERC developed numerous recommendations issued in a joint report, FERC, NERC and Regional Entity Staff Report, November 2021[5] including recommendation "9a" which recommends that utilities in southern states adjust load forecasts to reflect actual historic peak loads. These events and ensuing analyses continue to be reviewed by FRCC member companies for applicability to their systems.
  - The FRCC initiated a broad-based review plan to identify contributing causes, relevance to FRCC, and address any applicable near-term actions as well as longer term activities to identify any FRCC analysis or process improvement opportunities in load forecasting, extreme weather response and mitigation, resource adequacy methodologies as well as internal and external

[5] Report: *The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC, and Regional Entity Staff Report* https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

communications processes.

- FRCC member utilities continue to perform internal as well as FRCC wide reviews to better understand the potential loads that could be experienced based on actual historical weather events. Initial reviews of aggregate load forecasts based on winter 1989 and 2010 actual weather conditions identified the potential for customer load curtailments (rotating load shedding) to preserve the reliability of the FRCC systems during cold morning peaks should conditions similar to 1989 be experienced over the study horizon.

▪ The FRCC RS has been working to prepare a detailed 2 x 24 (hourly) evaluation of the sufficiency of resources to serve aggregated FRCC load across all hours of the peak summer and winter day. As of the writing of this assessment, the evaluation is not yet at a level of maturity from which to draw conclusions.

5.0 FRCC Reserve Margin Review

In February 2021, impacts from Winter Storm Uri caused multiple consecutive days with extremely low temperatures in Texas and elsewhere in the middle of the country which resulted in millions of customers being without power for days. In addition to the hardship these customers endured, the negative economic consequences for businesses in the affected areas and the state were significant. As a result, NERC and FERC developed numerous recommendations issued in a joint report, FERC, NERC and Regional Entity Staff Report, November 2021. One recommendation is that utilities (by Winter 2023-2024) "that forecast load within southern states should adjust their 50/50 forecasts to reflect actual historic peak loads that occurred during severe cold weather events in their footprints and reflect the potential for exponential load increase due to the resistive heating used in southern states". As a result, FRCC member utilities continue to perform internal as well as FRCC wide reviews to better understand the potential loads that could be experienced based on actual historical weather events.

FPL, whose load centers include the most southern part of Florida, estimated the largest increase in forecast load from its 50/50 forecast of any Florida utility when considering actual historical severe cold weather. This result is intuitive since the more northern parts of the state more frequently experience cold weather and that is then statistically captured in their "normalized" weather. As a result, FPL has developed a "Recommended" resource plan as well as "Business as Usual" resource plan, as part of their "Ten Year Power Plant Site Plan 2022-2031" filing to the FPSC. The aggregate FRCC L&RP compilation includes FPL's traditional P50 load forecast along with the resources and fuel diversification improvements that were identified as part of their "Recommended" resource plan. **Unless otherwise noted, the tables and charts in this reliability assessment include the P50 load forecast and the Recommended FPL resource plan.** For reference, the impacts on aggregate calculations have been annotated where practical. FPL has recently withdrawn its Recommended Plan from PSC consideration. However, one lesson learned from the 2021 Winter Storm Uri, is that a single calculation of reserve margin based on a 50/50 load forecast does not provide a complete picture of the probability of being able to serve load in extreme weather events.

The FRCC has a reliability criterion of a 15% minimum Total Reserve Margin based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming ten-year projected summer and winter peak hour loads, generating resources, and DSM resources on an annual basis to ensure that the Total Reserve Margin requirement is projected to be satisfied. The three Investor-Owned Utilities, Florida Power & Light Company (FPL), Duke Energy Florida (DEF), and Tampa Electric Company (TEC), are utilizing, along with other reliability criteria, a 20% minimum Total Reserve Margin planning criterion consistent with a voluntary stipulation agreed to by the FPSC[6]. Other utilities employ a 15% minimum Total Reserve Margin planning criterion.

If projections had shown a forecasted peak period for which the Total Reserve Margin requirement would not be met, such a projection would be researched and reflected in the annual Reliability Assessment Report. There are no such projections for the next ten years.

The information contained in the Figures and Tables in this report are consistent with information presented in the individual utilities' 2022 Ten-Year Site Plans (TYSP). These TYSPs present information from the utilities' latest resource planning work. As noted above, the calculations and aggregations this year include FPL's Recommended plan resource data paired with FPL's traditional P50 load forecast data as was provided to the FRCC through this year's regional load and resource plan data collection effort. Although this Recommended Plan was recently withdrawn from consideration by FPL, the FRCC Reserve Margin for winter is still above the 15% minimum criterion, using the P50 load forecast, without the additional capacity in FPL's Recommended Plan, as shown in *Figure 3*.

All reserve margin projections include both the projected firm impact of existing and projected solar resources as well as the firm impact of energy storage resources projected to come online over the planning horizon. The firm capacity value of solar, which varies by utility as some percentage of nameplate capacity for summer and is generally zero for winter, is discussed in more detail in Section 10.0 of this document. The firm capacity value of solar coupled to energy storage will continue to be evaluated as member utilities add more storage to their resource projections. Currently, each member utility assigns a firm capacity value to the energy storage projected in their resource plans, and those firm capacities are used in the calculation of the FRCC's Reserve Margin values.

Figure 1 below shows that the projected summer Total Reserve Margins, including the use of DSM, from the *2022 Regional Load & Resource Plan*[7] continue to be above the FRCC's minimum 15% Total Reserve Margin criterion. In fact, the 2022 projected summer Total Reserve Margins exceed 20% for every year in the ten-year forecast period. ***Figure 1*** also includes historical trends from the 2019, 2020, and 2021 LRP. Reserve Margins are generally comparable to those forecasted in 2021 with minor differences driven from timing and planned generation.

[6] Docket No. 981890-EU Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida, Order No. PSC-99-2507-S-EU, issued December 22, 1999 (http://www.floridapsc.com/library/filings/1999/15628-1999/15628-1999.pdf#search=99-2507-S-EU)
[7] *2022 Regional Load & Resource Plan*

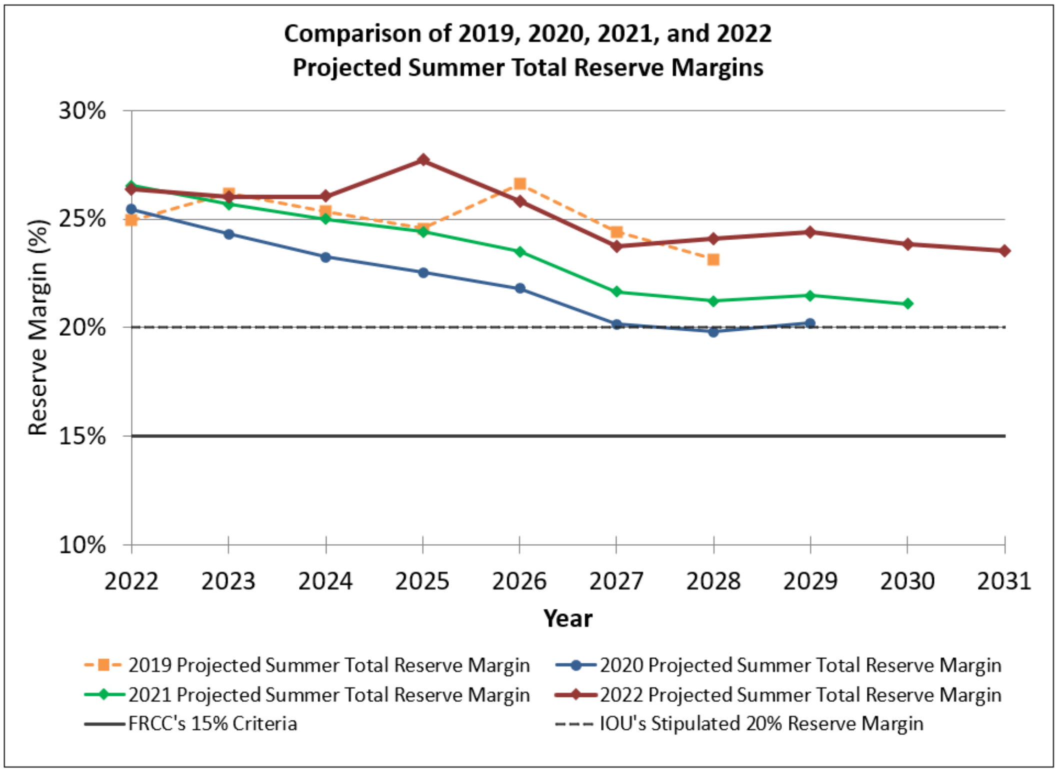

Figure 1
Trends in Projected Summer Total Reserve Margins

In a similar manner, ***Figure 2*** below shows the projected winter Total Reserve Margins, including the use of DSM, from the *2022 Regional Load & Resource Plan.* The 2022 projected winter Total Reserve Margins are also over 20% for every year in the ten-year forecast period. 2022 projected winter reserve margins are generally comparable with 2021 projections. In the latter years of the planning horizon, winter reserve margins increased from 2021 projections due in part to the additional winter capacity included from FPL's Recommended TYSP. Figure 2 also includes historical trends from the 2019, 2020, and 2021 LRP.

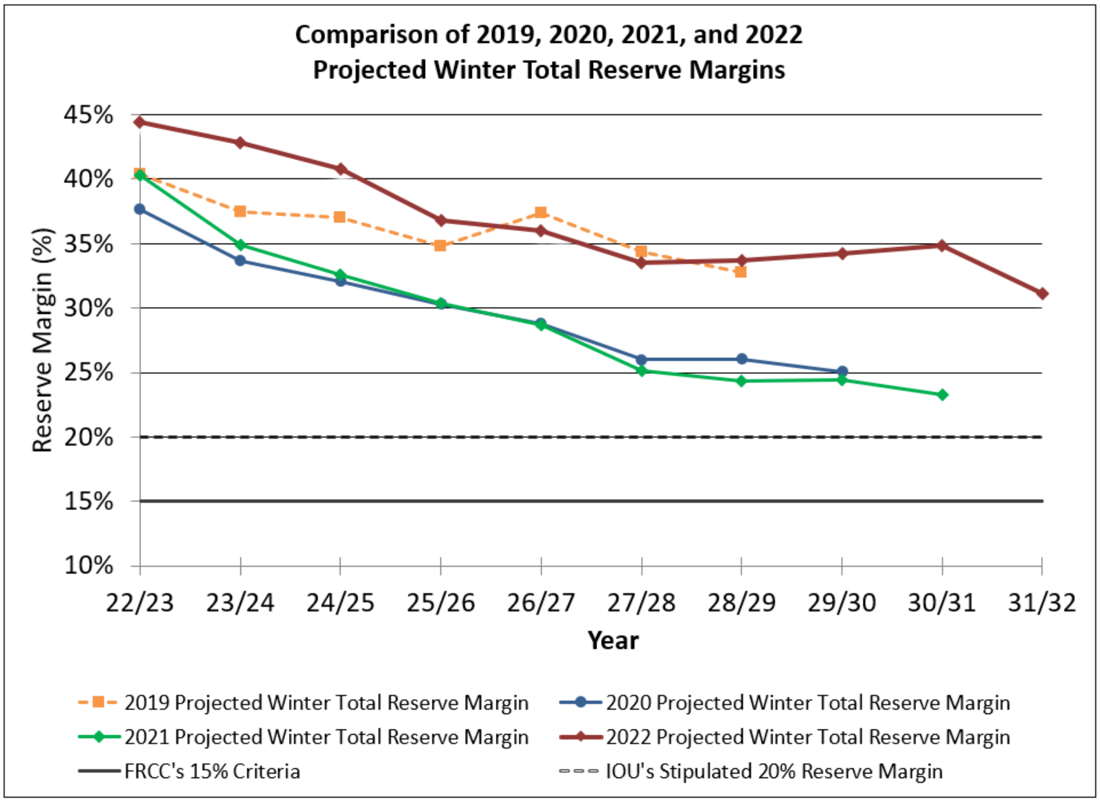

***Figure 2*[8]**

Trends in Projected Winter Total Reserve Margins

Specifically, and based on previous extreme events, FPL developed a new load forecasting approach that lies outside the traditional resource planning norms in order to clearly identify the potential risks and uncertainty associated with future extreme weather events and take incremental resource steps to mitigate those risks. As a result, FPL submitted two Ten-Year Site Plans to the FPSC. One in which FPL switched from using a P50 load forecast for all 12 months to a hybrid-type forecast that projects a P50 peak load for 11 months, with an extreme Winter peak load for the month of January (only) identified as their Recommended resource plan, and the other utilizing their traditional P50 load forecast identified as their Business as Usual (BAU) resource plan. Although the core FRCC LRDB included FPL's Recommended resource plan, FRCC has included ***Figure 3*** below as a point of reference to help identify the impacts to aggregate FRCC planned reserve margin using either plan. ***Figure 3*** shows the forecasted Winter Total Reserve Margin differences for the FRCC Region between aggregating FPL's Recommended Plan resources and FPL's BAU Plan resources. Both calculations assume all FRCC entities' P50 load forecast, and not FPL's extreme winter load forecast, which continues to be a highly debated topic across the industry and Regulating community.

[9] The winter season spans from the 4th quarter of one year through the 1st quarter of the next year. For example, the year 21/22 refers to the winter season spanning from the 4th quarter of 2021 through the 1st quarter of 2022.

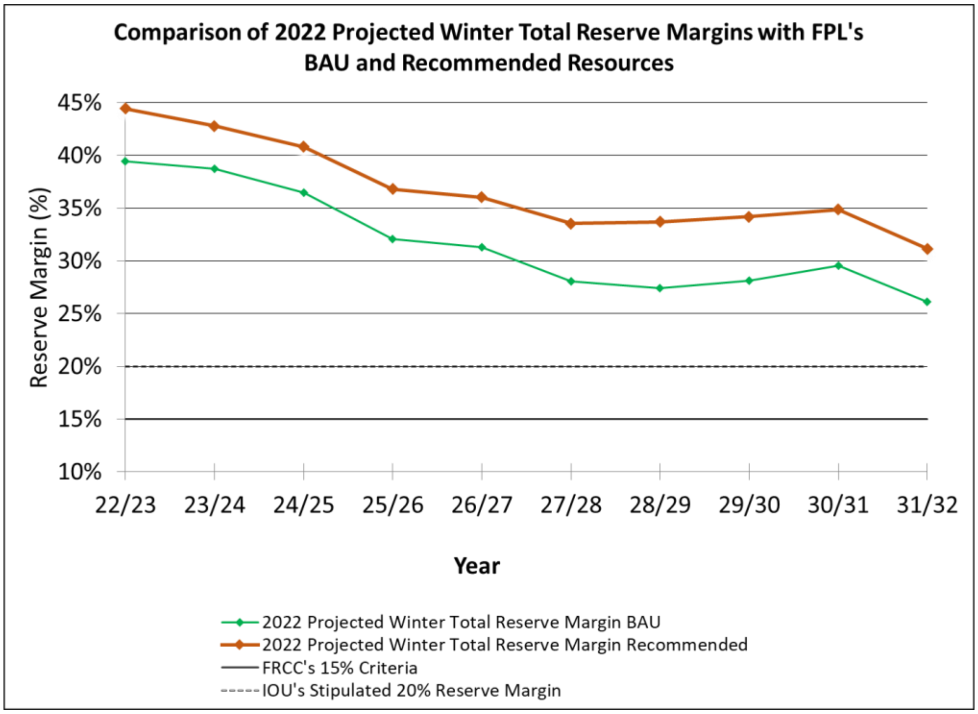

Figure 3

Comparison of 2022 FRCC Regional Projected Winter Total Reserve Margins between FPL's BAU and Recommended Resources

Planning Reserve Margins generally project demand based on a 50/50 forecast. When NERC discusses a 15% Reserve Margin for predominantly thermal systems (in Florida 15% and 20% reference Reserve Margins), those Reserve Margins are associated with a 50/50 forecast. Therefore, a Reserve Margin calculation with a higher forecast load is not comparable to a reference Reserve Margin. Even though the results are not directly comparable, in **Figure 4** below the green line of the chart uses a 50/50 forecast for all Florida entities. The orange line uses a 50/50 forecast for all Florida entities except FPL. For FPL an extreme Winter peak load is utilized (from FPL's Recommended Plan).

Figure 4 shows a theoretical forecasted Winter Total Reserve Margin difference for the FRCC Region between aggregating FPL's Recommended Plan load and FPL's BAU Plan load. Note: The resources assumed in Figure 4 are the same as in Figure 3 (FRCC total resources with FPL's Recommended Plan). Only the total FRCC load differs in the orange line calculation, with the 50/50 forecast load being used for all Florida entities except FPL, combined with FPL's extreme Winter peak load.

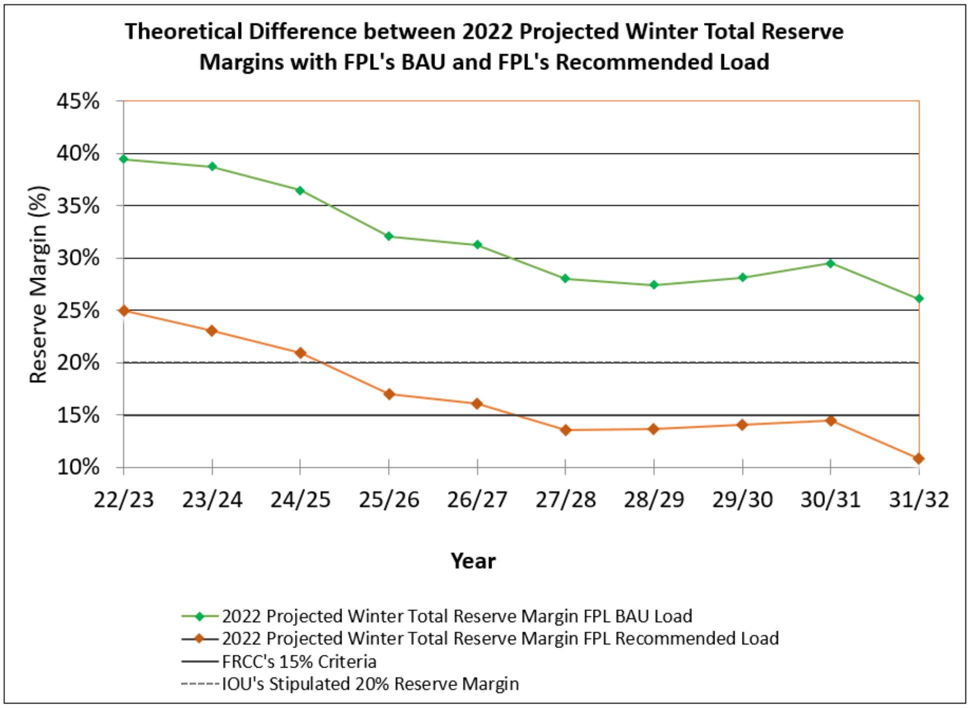

Figure 4

Theoretical Difference between 2022 FRCC Regional Projected Winter Total Reserve Margins between with FPL's BAU and FPL's Recommended Load

6.0 FRCC Resource Adequacy Criteria Review

Introduction

Loss-Of-Load-Probability (LOLP) projections are developed in analyses that are conducted every other year. In addition, projections of generator Forced Outage Rate (FOR) and Availability Factor (AF) are developed annually. The results of these analyses are utilized, in combination with the above-described Total Reserve Margin review, to determine if the planned resources for the FRCC Region are adequate to meet FRCC and FPSC requirements.

LOLP Analysis

The FRCC has historically used an LOLP analysis to support the adequacy of reserve levels for the FRCC Region. The LOLP analysis utilizes probabilistic analysis methods to quantify the ability of the generation system resources to reliably meet expected demand, incorporating the uncertainties associated with generation reliability including unit forced outage rates, maintenance schedules, load uncertainty, and demand response capabilities that vary on a seasonal basis. In response to the increasing penetration of utility-scale solar and other energy-limited resources as well as the drive to model the region as accurately as possible, the FRCC has updated their modeling approach for these resources. For the 2022 LOLP analysis, the RS collected projected hourly solar output and energy storage charging and discharging profiles for all utility-scale units and treated them as a modifier to the load in order to further improvement the assessment model. The purpose is to verify that the projected LOLP for the system does not exceed the maximum target LOLP of 0.1 day in a given year. In addition to maintaining this LOLP level, the FRCC established an additional Regional Reserve Margin Planning Criterion (also known as a Resource Adequacy Criteria) of a minimum 15% Total Reserve Margin for both summer and winter versus firm load.

The most recent LOLP analysis was conducted in 2022. "Base" LOLP projections were obtained for the FRCC Region for the years 2022 through 2026 using updated assumptions and forecasts that correspond with the Florida utilities' 2022 TYSPs. Beyond the base or "reference" case values for LOLP, projected LOLP values for a variety of scenarios were considered, including: (i) no availability of firm imports, (ii) no availability of load management/demand response (DR) types of DSM programs, and (iii) a high load case.

Results indicate that the FRCC Region is projected to be reliable from an LOLP perspective through 2026. In other words, the FRCC Region's electric system is projected not to exceed the planning maximum LOLP criterion of 0.1 days per year with all transmission facilities in service for the reference case and the scenario cases. The projected LOLP values are shown in ***Table 1*** below.

Year	Base Case	No Availability of Firm Imports	No Availability of Demand Response	High Case
	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2022	0.000003	0.000957	0.015117	0.000008
2023	0.000003	0.000441	0.015003	0.000008
2024	0.000002	0.000652	0.014572	0.000009
2025	0.000004	0.000688	0.010994	0.000011
2026	0.000002	0.000597	0.008826	0.000009

Table 1
2022 LOLP Results[10]

Forced Outage Rates (FOR) and Availability Factors (AF)

Generating unit reliability is a primary driver of LOLP results. The FRCC Resource Subcommittee tracks and monitors capacity (MW)-weighted FOR and AF measures for individual utility systems and the FRCC Region as a whole. This assessment was again conducted as part of the 2022 Load and Resource Reliability Assessment. The individual utility system information is aggregated to develop MW-weighted FRCC Regional FOR and AF values. Actual and forecasted FOR and AF values are then compared to historical values. Projections of these annual measures for individual utilities and the region, plus projected changes from year-to-year, are implicit indicators of system reliability from an LOLP perspective.

In the current analysis, both yearly capacity weighted FOR and AF projected values for each utility system were calculated. The calculations were based on each utility's latest planning assumptions and historic forced outage information as presented in each utility's 2022 TYSP. These 2022 projections for FOR and AF values were compared to the values projected in 2019, 2020, and 2021.

As seen in ***Figure 5*** below, the 2022 projection of FOR values remain generally in-line with projected values from the last several years. The current projected FOR values are in a relatively narrow range and continue to decline. This trend is also consistent with projections from the prior years. The projected FOR values are one

[10] The 2022 LOLP results are based on: (i) a load variation model and (ii) a manual approach to generator maintenance inputs which typically results in higher LOLP values than would result if using an automatic maintenance approach.

driver of the projected low LOLP base case values from the 2022 LOLP analyses presented above in ***Table 1***. This consistency in FOR projections[11] further supports the finding that the FRCC Region is projected to remain resource adequate and maintain its reliability from 2021 through 2031. In addition to the low projected FOR values, low projected LOLP values presented above are likely driven by the updated modeling approach for utility-scale solar and energy limited resources. The updated modeling approach more accurately represents the real-time output of these units at time of peak which was understated in the previous approach.

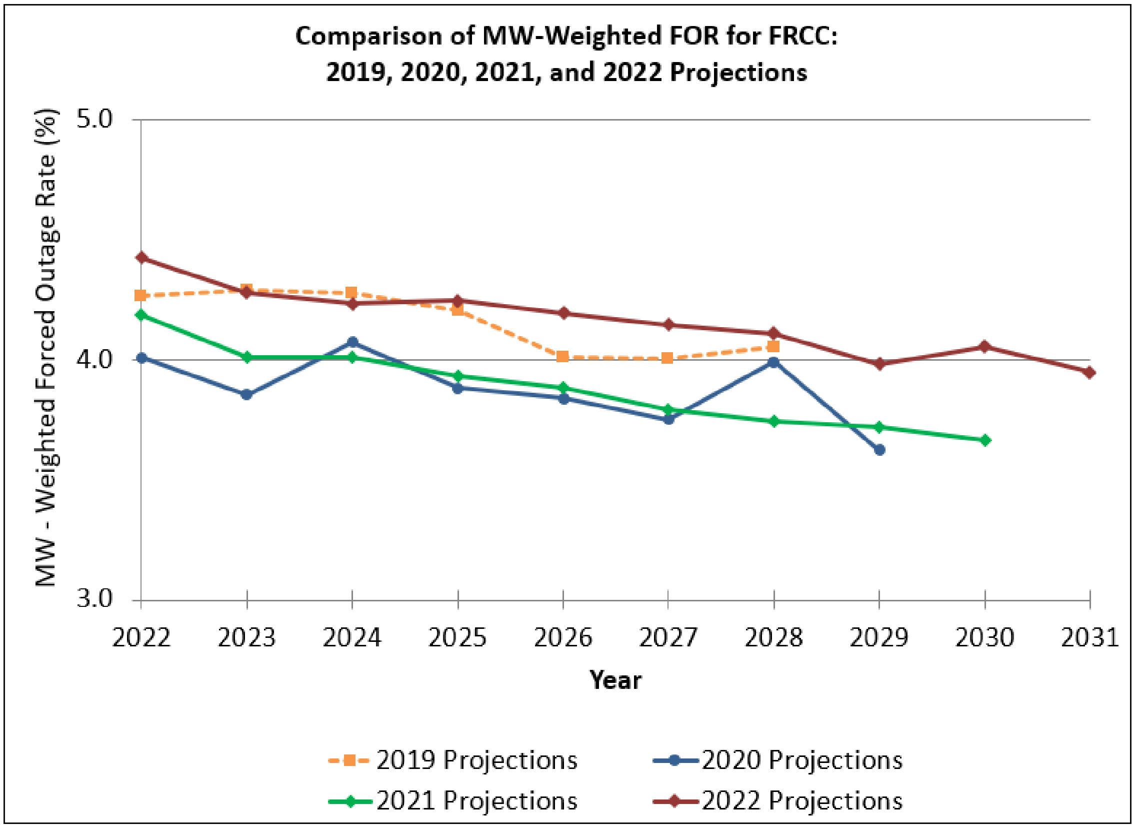

Figure 5
Trends in Projected Forced Outage Rates (FOR)

Though unit AF is not an input to LOLP calculations, it is often used as an indicator that generally correlates well with reliability data. The projections from resource planning work conducted in the previous four years remain consistent in a narrow range from approximately 85% to 90%. For 2022 projections of MW-weighted AF, the dip in 2024 is due to individual unit retirements as seen in ***Figure 6*** below.

[11] For some FRCC members, solar is currently modeled in the process using typical weather year shapes.

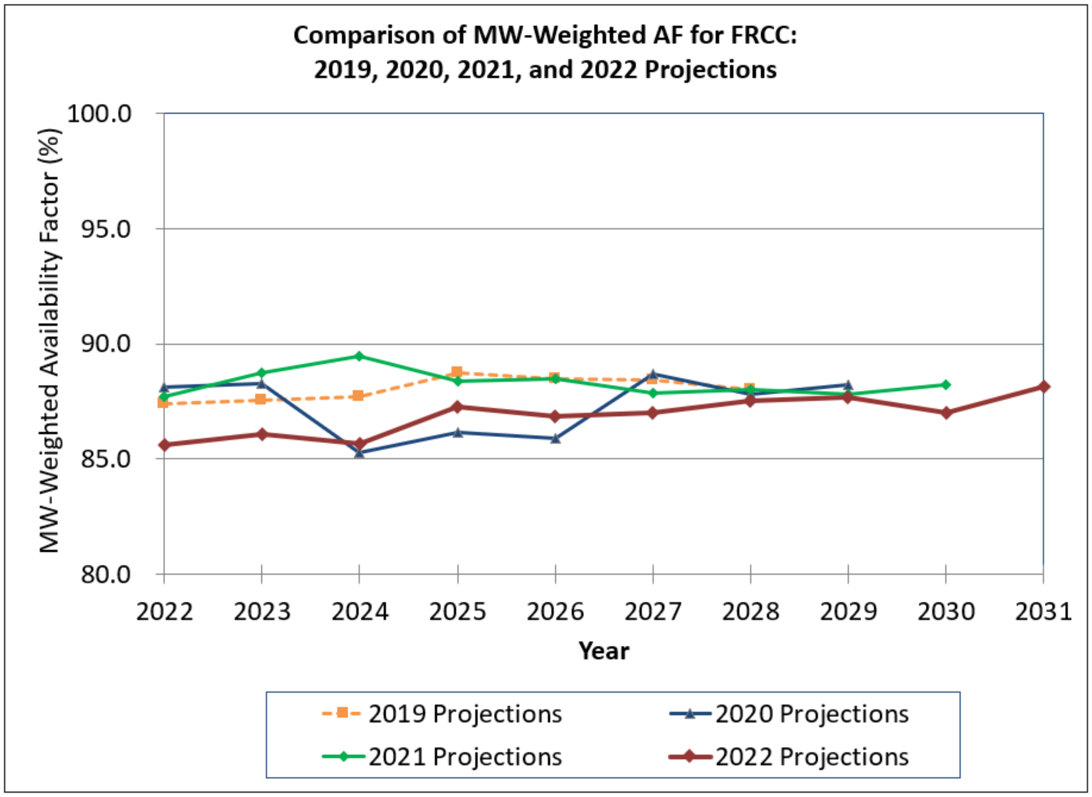

Figure 6
Trends in Projected Availability Factors (AF)

The results of the AF analyses, combined with the results of the FOR analyses depicted in ***Figure 6,*** the very low projected LOLP base case results for 2022 – 2026, and the projections of Total Reserve Margins for all years that are above the FRCC's minimum Total Reserve Margin Planning Criterion of 15% (as presented in the *2022 Regional Load & Resource Plan* document and presented in the previous section in ***Figure 1*** and ***Figure 2***), support a conclusion that the FRCC Region is projected to continue to be reliable throughout the ten-year period addressed in this document.

Additional Resource Adequacy Reviews and Metrics

<u>Generation Only Reserve Margin (GRM)</u>

In addition to the Deterministic Reserve Margin, LOLP, and FOR/AF analyses, the RS examines the extent to which the system's projected Total Reserve Margin values rely upon DSM to meet and maintain the FRCC's 15% Total Reserve Margin Planning Criterion. Historically, FPL adopted a minimum 10% generation-only reserve margin (GRM) as a third reliability criterion in its Integrated Resource Planning (IRP) process. The GRM criterion supplements FPL's other two reliability criterion, a 20% minimum total reserve margin for summer and winter and a maximum LOLP of 0.1 day per year. FPL's GRM criterion is similar in concept to the supply-side reserve margin reliability criterion that TEC has used in its IRP process for more than a decade. Both criteria are essentially designed to ensure that there is an adequate generation component as the utilities meet their 20% total reserve margin criterion.

To examine the extent to which the FRCC Region's system is dependent upon DSM, and whether the system is projected to become more dependent upon DSM over time, a projection of annual "generation-only" Reserve

Margin[12] values are analyzed by the RS each year. The generation-only Reserve Margin analysis includes aggregating the utilities' 2022 TYSP projections in which incremental and cumulative load management, incremental utility program energy conservation/energy efficiency and other demand reduction contributions, are excluded. The resulting generation-only Reserve Margin projection, presented in ***Figure 7*** below, shows the projected future Reserve Margins when considering only generating unit contributions (existing and future thermal resources and assumed typical weather performance of solar generation) compared against the Reserve Margins with contributions of incremental and cumulative load management, incremental utility program energy conservation/energy efficiency, and other demand reduction contributions.

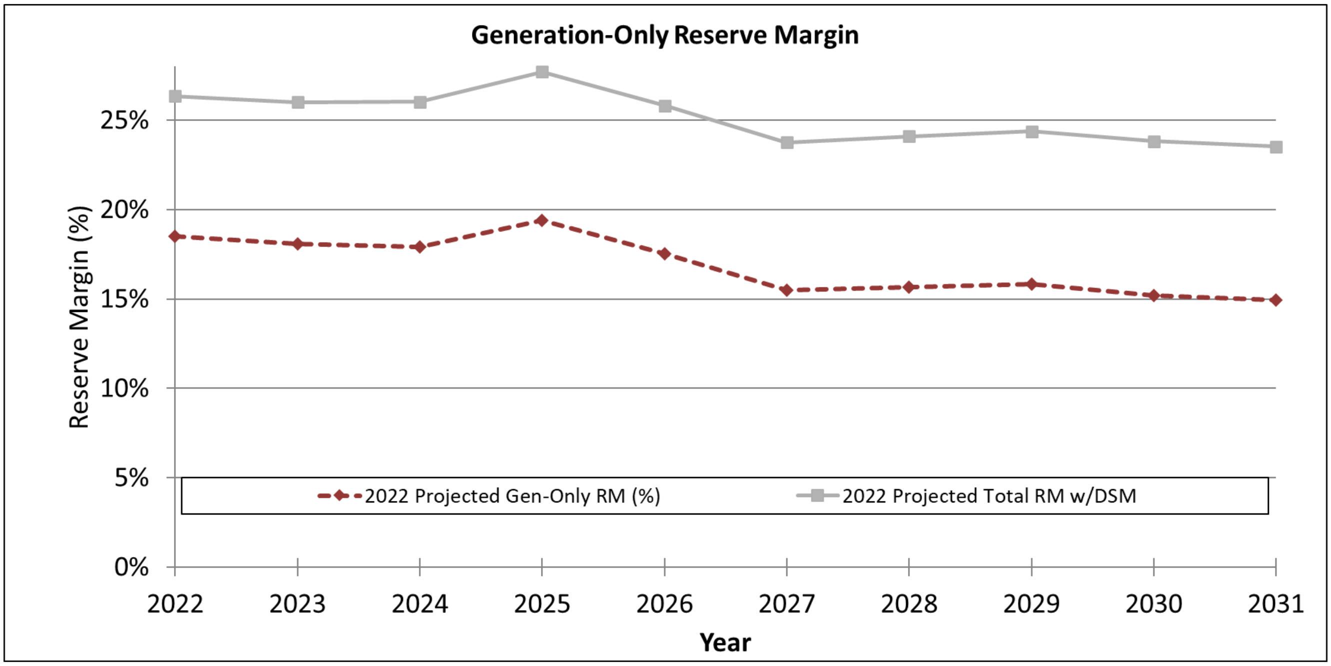

Figure 7
Projected Generation-Only Reserve Margin

As shown in ***Figure 7***, the generation-only Reserve Margin does not fall below the FRCC's 15% Total Reserve Margin Planning Criterion. In previous years, FRCC was increasingly reliant upon firm DSM towards the end of the planning horizon. In this year's planning horizon, additional resources have been added beginning in 2026, resulting in FRCC maintaining at least a 15% GRM through 2031. Increased reliance on DSM versus the near term remains, as the gen-only reserve margin declines from 2022 levels by 2031. The FRCC and individual utilities continue to evaluate generation-only Reserve Margin projections and their potential implications for system reliability.

As the integration of intermittent renewable resources (particularly solar and energy storage) continues to increase in penetration at FRCC member utilities, the historical adequacy assertions will be challenged and will require additional analyses and metrics to accurately factor in the dispatchability challenges posed by these resources. Recognizing that solar is expected to contribute to traditional peak hours, times of day with high or persistent cooling load without sunlight, must be carefully examined to ensure sufficient firm capacity in such hours over the longer-term planning horizon. The operational combination of energy storage and solar must also

[12] For purposes of calculating projected 'generation-only reserve margin' values, the following formula was used: (total capacity - load forecast) / load forecast, in which the following DSM components have been removed from the calculation: existing load management capability, projected new incremental load management capability, and projected new energy efficiency/energy conservation utility program additions.

be analyzed with more depth to understand the extent to which future solar output shapes can be optimized to support reliability.

Fuel Deliverability

Natural gas is the predominant source of fuel for electric generation in the FRCC Reliability Area. This is expected to continue over the coming years. While utilities continue to install natural gas generation, the percentage of electric energy generated by natural gas is expected to drop from approximately 68% to approximately 65% of total net energy for load by 2031. This drop correlates to a projected increase in electric energy generated by Renewable energy sources from approximately 5% of net energy for load in Florida in 2022 to approximately 18% of net energy for load in 2031.

The state has no native natural gas production and currently relies primarily on three existing interstate natural gas pipelines: Gulfstream Natural Gas System (Gulfstream), Florida Gas Transmission Company (FGT), and Sabal Trail Transmission (Sabal Trail). Florida also utilizes the Central Florida Hub, a location near Orlando where Sabal Trail has a bi-directional interconnection with wheeling capability to FGT and Gulfstream. A relatively small amount of gas is also transported into FRCC via Southern Natural's Cypress and South Georgia pipeline systems. Gulf South Pipeline Company (Gulf South) also has a minimal delivery capability directly into peninsular Florida. FRCC-Member contracted capacity for delivery to Florida markets is currently approximately 0.03 Bcf/day on Gulf South.

The FRCC Planning Committee performs a biennial assessment of gas infrastructure and compares the utilities' expected peak day gas burn to available gas infrastructure to identify any near-term infrastructure deficiencies. The most recent assessment found that in aggregate FRCC members hold the vast majority of contracted firm transportation pipeline capacity delivering into the State of Florida and that pipeline capacity and member resources are adequate to meet projected peak day gas requirements (summer and winter) through 2029, with the assumption that any short-term capacity shortfall can be met with member backup fuel capabilities or market solutions.

In terms of ensuring the reliability of Florida's natural gas supply, utilities have added additional "upstream pipeline transportation capacity" to access onshore production, shale gas reserves as well as natural gas storage facilities. This upstream capacity allows Florida's utilities to diversify natural gas supply away from the Gulf of Mexico and to tap the abundant shale gas reserves in Texas, Louisiana, Oklahoma, and other states. However, efforts by utilities in managing gas transportation risks, decreasing costs, and increasing supply diversity is limited by the existing access provided by the current pipeline delivery infrastructure. The FRCC, via the FRWG, performs periodic studies to assess and evaluate potential natural gas delivery capacity losses that can occur as a result of such pipeline outages and further evaluates contingency planning in the event of such outages. Finally, via the RS, the FRCC continues to evaluate the long-term adequacy of pipeline delivery infrastructure to meet the projected natural gas requirements of electric generation assets in the region during the ten-year planning horizon. The most recent study results projected that the Natural Gas pipeline capacity in the region will be sufficient to meet the projected electric generation needs and did not indicate a need for incremental pipeline capacity. Further flexibility to support gas supply adequacy is available in the form of redispatch that leverages alternative thermal resources. Additionally, a long-term interruption of any of the primary pipelines serving the state could significantly impact the adequacy of resources within the FRCC to serve customer loads during the period required to repair the affected pipeline.

Environmental Compliance

At this time, the RS believes that current environmental requirements imposed by Federal, State, and local authorities that may impact the capability and operation of generation resources are appropriately addressed within the individual utility resource planning processes. However, FRCC Members are monitoring recent developments with potential legislation surrounding the "CLEAN Future Act" and associated variants being proposed in Congress and will provide updates on potential implications to FRCC reliability in subsequent cycles.

7.0 Load Forecast Evaluation

In aggregate, customer growth was .99% in 2021, 0.8% higher than what had been projected. FRCC Region's average per-customer consumption decreased for the Rural & Residential and increased for the Industrial Class and the Commercial Class from 2020.

Net Energy sales are projected to grow at a higher rate, relative to what was previously forecasted, with an average annual growth rate of 0.96%[1] The projected average annual growth rate for customers is 1.22%[1]. In general, higher than normal temperatures experienced over the past several years are playing a noticeable role in the somewhat higher than projected average consumption per customer. These forecasts continued to project that Florida's economy would continue to see steady growth, but weather is more of a factor in higher than projected sales and average consumption than growth in the economy as it relates to short-term fluctuations in energy and peak demand. Impacts of conservation and energy efficiency, including the impacts of higher energy efficiency building codes and appliance standards, continue to contribute to the weather-normalized declines in per-customer consumption both on an actual and projected basis. While a decline in state-level vacancy rates in the residential sector could result in some short-term boosts to average residential usage, this is in part offset by declines in smaller-sized commercial customer accounts as the retail sector continues to be challenged by online commerce and associated supply-chain disruptions.

Electric vehicles and private Photovoltaic factors were included in the aggregate forecasted totals for both energy and demand as applicable, for the various utility systems that comprise FRCC. Penetration in the Florida market of private dependable AC solar capacity during peak periods and electric vehicles is still relatively low but expected to grow steadily. FRCC's Load Forecast Working Group (LFWG) will continue to monitor trends in solar uptake and electric vehicle penetration and will coordinate with the FRCC RS on best practices for determination of dependable AC solar capacity during peak periods as well as the impact of electric vehicle charging on system peak demand, as applicable.

The impacts on load growth from the *Energy Policy Act of 2005*[13] and the *Energy Independence and Security Act of 2007*[14] were reviewed. Most utilities incorporate these mandated energy efficiency impacts in their load forecasts. Other utilities capture these embedded efficiency trends that have been taking place historically through their econometric models.

The FRCC aggregates the individual peak demand forecast of each of its member utilities by summing these forecasts to develop the FRCC Region forecast. FRCC has pursued this avenue using the logical assumption that each utility is most familiar with its own service territory and the behavior patterns of its customer base. The load forecast evaluation process undertaken by FRCC is designed to understand which forecasting models are used, and, to a certain degree, seek consistency of assumptions across all utilities. FRCC's LFWG reviewed each utility's forecast methodology, input assumptions and sources, and output of forecast results. Reasonability

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[13] Energy Policy Act of 2005 (https://www.energy.gov/sites/prod/files/edg/media/HR6PP%281%29.pdf)
[14] Energy Independence and Security Act of 2007 (https://www.govinfo.gov/content/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf)

checks were performed comparing the historical past with the projected load growth, use per customer, weather-normalized assumptions, and load factors.

Although a significant amount of advancement has been achieved in forecasting and statistical modeling, there remains an amount of risk (in the form of forecast variance) associated with the uncertainties embedded in the primary factors that determine the demand for electricity. The uncertainties that are most noticeable are departures from historical weather patterns, recent population growth, performance of the local and national economy, size of homes and number of homes being built, inflation, interest rates, price of electricity, changing electric end-use technology, appliance efficiency standards, and changes in consumption patterns. In the short-run, weather deviations from normal conditions tends to be the most important factor. However, population growth, economic performance, price of electricity, changing technology, changing consumption patterns, and more-efficient building codes and standards also play crucial roles in explaining the growth in demand for electricity over the long-run. The load forecast should provide an unbiased estimate of the future load after accounting for these uncontrollable factors using a theoretically sound and transparent modeling framework. The projections of load should not consistently under- or over-forecast the actual loads. Additionally, it is desirable that the forecasting processes used by the member utilities of FRCC exhibit continuous improvement in the theoretical bases utilized to develop forecast equations and a high level of scrutiny for the sensibility of parameters and relationships that are then leveraged to simulate future conditions. While it can be attractive to focus on short-term weather-normalized forecast variance, a poorly specified series of models (containing spurious correlation or various other econometric problems) could still show limited forecast variance by happenstance. Such a model would have limited variance decomposition capabilities and would not be appropriate to support long-term resource or financial decisions.

Methodology

The FRCC's evaluation process of each individual member's load forecast and forecasting methodologies is described in the following sections.

Models

The LFWG reviews the properties and theoretical specifications of the forecasting models utilized to develop the individual utility's forecast without recommending or endorsing a particular type of model. There is an evident preference for econometric models over end-use modeling by utilities in the state of Florida. However, more and more utilities are finding it advantageous to combine econometric models with other types of forecasting models (which were basically hybrids of end-use and econometric models).

The LFWG was attentive as to the forecasting results and cannot categorically endorse one type of model over the other based upon the results obtained. The LFWG does not consider it prudent to standardize the types of forecasting models to be used in Florida because each service territory is different and certain types of models seem to yield better results under specific conditions. It is customary that all utilities update and refine their models with each additional year of actual data, which ensures that the most recent correlations and associations embedded in the data are captured and that the models are calibrated accordingly. Furthermore, this ensures that the starting point of each forecast series is adjusted to the latest historical value for load or customer growth.

Inputs

The input assumptions that feed the forecasting models used to project load, as well as the sources of these inputs, were assessed. The primary inputs that were examined included: Florida population and customers, the price of electricity, normal weather assumptions, an economic outlook for income and employment levels and saturations/efficiencies of electrical appliances in those models that combine end-use technology with econometric modeling. The source data for Florida's population was the *Florida Legislature's Office of Economic and Demographic Research (EDR)*, which works in conjunction with the *Bureau of Economic and Business Research from the University of Florida*[15]. *Moody's Economy.com*[16], *Global Insight*[17], and *Woods and Poole Economics, Inc.*[18], all reputable forecasting organizations, were additionally utilized for historical and projected economic data. The price of electricity was derived internally by each utility and consisted of base rates and all "pass-through" clauses filed with the FPSC. The National Oceanographic and Atmospheric Administration (NOAA) provided historical weather data used in model estimation and calibration.

Because each utility's service territory has its own characteristics, different time horizons were used to determine the values for normal weather that best fits their territory. As such, some utilities employed the average weather over the last 20 years, others the last 10 or 30 years, and some used longer time periods to define what was considered as "normal" weather. Some utilities employed a Monte-Carlo simulation while others chose a rolling average or rolling median. There is no prescribed correct measure of "normal" weather and utilities will rely on the definition that best portrays the observed weather patterns in their service territory. This member-defined definition of "normal" weather is then employed throughout the forecast horizon by all utilities.

The economic outlook of the local and national economy was obtained from several reputable economic forecasting firms such as *Global Insight*, *Woods and Poole*, and Moody's *Economy.com.* The utilities across the State are nearly divided evenly among the three. All three firms are highly regarded in the industry. By using more than one firm, the risks of producing flawed results were minimized because somewhat different economic perspectives were relied upon by each entity.

Outputs

The current forecast was compared to the prior forecast developed last year (see ***Table 2*** below). The 2022 NEL is forecasted to be higher than the actual 2021 NEL. The current compound annual growth rate (CAGR) for NEL is 0.93% for the forecast period. The 2022 firm winter peak demands are forecasted to be lower than the 2021 actual winter peak demands. For the firm winter peak demand, the CAGR is expected to be approximately 1.06% for the forecast period. For the summer peak demand, the CAGR is expected to be 1.09% for the forecast period[19].

Load Factor

Several other ad-hoc measures were examined to assist in the determination of the reasonableness of the load forecast. The load factor, which is the relationship between the average load and the peak load, was examined comparing projected and historical values for this parameter. The resulting confirmation that historical and projected load factors were aligned helped to provide an increased level of assurance that no given component of the load forecast was unreasonable. While historical load factor figures can be influenced by extreme temperatures in the hour of the annual peak, all member utilities exhibited reasonable load factors when comparing these values in the historical and projected periods. In aggregate, the implied load factor trend for the

[15] Bureau of Economic and Business Research (https://www.bebr.ufl.edu/)
[16] Moody's Economy.com (http://www.economy.com)
[17] Global Insight (http://www.globalinsight.com)
[18] Woods and Poole (http://www.woodsandpoole.com)
[19] These CAGR values are reflective of firm peak demand values which incorporate the impacts of Demand-Side Management programs while ***Table 2*** does not include these impacts; therefore, the growth rates will not be congruent between the two.

FRCC continues to decrease, as energy is projected to grow at a slower rate than net firm winter and summer peaks over the forecast horizon.

Results

The comparison between the 2021 and 2022 forecasts for summer and winter peaks are shown in ***Table 2.***

Summer Peak					
	Forecast		Difference		
Year	2021	2022	MW	%	
2022	51,071	51,205	**134**	0.3%	*
2023	51,779	51,986	207	0.4%	
2024	52,443	52,305	-138	-0.3%	
2025	53,044	52,827	-217	-0.4%	
2026	53,552	53,391	-161	-0.3%	
2027	54,111	53,947	-164	-0.3%	
2028	54,611	54,427	-184	-0.3%	
2029	55,341	55,140	-201	-0.4%	
2030	56,145	55,823	**-322**	-0.6%	

Winter Peak					
	Forecast		Difference		
Year	2021	2022	MW	%	
2022/23	47,151	47,350	**199**	0.4%	*
2023/24	47,759	47,563	-196	-0.4%	
2024/25	48,310	47,984	-326	-0.7%	
2025/26	48,909	48,881	-28	-0.1%	
2026/27	49,412	49,330	-82	-0.2%	
2027/28	49,869	49,822	-47	-0.1%	
2028/29	50,470	50,404	-66	-0.1%	
2029/30	51,023	50,948	-75	-0.1%	
2030/31	51,563	51,145	**-418**	-0.8%	

Values are non-coincident peaks

*Reflects the integration of Gulf Power Company Load Forecast into the FPL Load Forecast (effective 1/1/2022)

Table 2

Comparison of 2021 and 2022 Forecasts

For the first forecast year (2022 Summer, 2022/23 Winter) shown above in ***Table 2***, the 2022 forecast of the summer period peak demand of the integrated FRCC system is projected to be higher than expected when compared to the 2021 forecast for the last overlapping forecast year by approximately 134 MW (0.3%). Also, the 2022 forecast of the winter peak demand is projected to be higher when compared to the 2021 forecast by approximately 199 MW (0.4%).

For the last forecast year (2030 Summer, 2030/31 Winter) shown above in ***Table 2***, the 2022 forecast of the summer period peak demand of the integrated FRCC system is projected to be lower than expected when compared to the 2021 forecast for the last overlapping forecast year by approximately 322 MW (0.6%). Also, the 2022 forecast of the winter peak demand is projected to be lower when compared to the 2021 forecast by approximately 418 MW (0.8%).

Over the last ten years of actuals, the FRCC Region had a CAGR of 0.99%[20] for summer peak demand. The current study period (2022-2031) projection has a CAGR of 0.93%**Error! Bookmark not defined.**.

The confidence level that can be placed on these forecasts can be deduced by examining the historical performance of the aggregate forecasts. The summer peak analysis of the forecasted peaks versus the actual peaks, shown in ***Table 3***, indicates that since 2012, there has been a tendency to over-forecast the summer peak demand in the FRCC aggregate ten-year load forecast. This is in large part a function of the 2007-2009 recession, and the tendency of economic providers to over-forecast the pace of the economic recovery.

The first column in ***Table 3***, labeled "Actual Summer Peak (MW)", corresponds to the actual non-coincident summer peak. The next ten columns show the forecast as it was presented in the Regional Load & Resource Plan

[20] This CAGR is significantly impacted by the deep and prolonged recession that originated approximately 12 years ago ("Great Recession") and consequently, the forecast period reflects the expectation of a gradual, protracted recovery from said economic contraction.

for each of the ten years listed from 2012 to 2021. The bottom table is the percent forecast variance, derived by comparing actual to forecast demands. A positive variance means that the "actual" was larger than the forecasted value for the corresponding year, meaning an under-forecast. A negative forecast variance means an over-forecast.

COMPARISON OF SUMMER PEAK FORECASTS TO ACTUAL PEAKS (MW)

Year	Actual Summer Peak (MW)	Forecasted Summer Peaks 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2012	43,946	45,613									
2013	44,549	46,270	45,668								
2014	45,794	46,857	46,338	45,759							
2015	45,716	47,758	47,053	46,719	46,452						
2016	47,660	48,594	47,650	47,615	47,304	47,654					
2017	46,471	49,244	48,285	48,501	48,097	48,125	47,508				
2018	45,327	49,643	48,881	49,147	48,784	48,648	48,042	47,505			
2019	48,432	50,356	49,603	49,852	49,498	49,266	48,587	48,264	47,670		
2020	46,638	52,186	50,356	49,603	49,852	49,498	49,266	48,587	48,264	48,334	
2021	46,306	53,083	51,191	50,336	50,554	50,133	49,873	48,947	48,739	48,710	48,334

FORECAST VARIANCE (PERCENT)

Year	Actual Summer Peak (MW)	Forecasted Summer Peaks 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2012	43,946	-3.7%									
2013	44,549	-3.7%	-2.5%								
2014	45,794	-2.3%	-1.2%	0.1%							
2015	45,716	-4.3%	-2.8%	-2.1%	-1.6%						
2016	47,660	-1.9%	0.0%	0.1%	0.8%	0.0%					
2017	46,471	-5.6%	-3.8%	-4.2%	-3.4%	-3.4%	-2.2%				
2018	45,327	-8.7%	-7.3%	-7.8%	-7.1%	-6.8%	-5.7%	-4.6%			
2019	48,432	-3.8%	-2.4%	-2.8%	-2.2%	-1.7%	-0.3%	0.3%	1.6%		
2020	46,638	-10.6%	-7.4%	-6.0%	-6.4%	-5.8%	-5.3%	-4.0%	-3.4%	-3.5%	
2021	46,306	-12.8%	-9.5%	-8.0%	-8.4%	-7.6%	-7.2%	-5.4%	-5.0%	-4.9%	-4%

Values are non-coincident peaks

Table 3
Comparison of Summer Peak Forecasts to Actual Peaks and Forecast Variance

Over the short-term, customer growth and economic conditions can differ from the long-term assumptions used to develop a particular vintage of a load forecast. The utility forecasts do not attempt to capture short-term deviations to customer growth and economic conditions but seek to deliver as objective an outcome as possible in terms of projected load for the state of Florida over the next ten years. Since the FRCC level forecast is merely an aggregation of individual entity forecasts, there is no incremental improvement or retrenchment in sensibility resulting from the FRCC amalgamation process.

The analysis for winter peaks is shown on ***Table 4.*** A perfunctory review noting the negative values would suggest a tendency to over-forecast given the predominance of projected peaks higher than the observed "actuals". Weather and temperature variations typically differ from the "normalized" weather assumptions used to develop the individual utility electric forecasts. In Florida, this is much more pronounced for the winter months compared to the summer months. Therefore, this weather volatility caused a significantly larger number of over-forecast occurrences.

Florida does not experience a cold winter very often. Nevertheless, each utility in its resource plan considers the eventuality of a severe winter peak. The winter of 1989 turned out to be the coldest winter on record (or very close) in many areas of the FRCC Region. Utilities utilized several load management/demand response programs to serve their firm load throughout the peak load period.

COMPARISON OF WINTER PEAK FORECASTS TO ACTUAL PEAKS (MW)

Year	Actual Winter Peak (MW)	Forecasted Winter Peaks 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2012/13	36,733	46,864									
2013/14	38,842	46,367	46,456								
2014/15	42,597	47,568	47,161	44,636							
2015/16	37,881	48,172	47,722	45,668	45,600						
2016/17	36,309	48,797	48,251	46,415	46,019	45,521					
2017/18	42,877	49,298	48,773	47,165	46,412	45,962	44,836				
2018/19	36,008	49,908	49,377	47,692	46,912	46,546	45,350	44,190			
2019/20	39,192	50,570	49,989	48,241	47,381	47,035	45,769	44,667	44,737		
2020/21	37,171	51,218	50,612	48,769	47,794	47,525	46,270	45,292	47,314	44,737	
2021/22	42,413	51,921	51,249	49,323	48,199	47,993	46,659	45,781	47,780	47,314	46,467

FORECAST VARIANCE (PERCENT)

Year	Actual Winter Peak (MW)	Forecasted Winter Peaks 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
2012/13	36,733	-21.6%									
2013/14	38,842	-16.2%	-16.4%								
2014/15	42,597	-10.5%	-9.7%	-4.6%							
2015/16	37,881	-21.4%	-20.6%	-17.1%	-16.9%						
2016/17	36,309	-25.6%	-24.7%	-21.8%	-21.1%	-20.2%					
2017/18	42,877	-13.0%	-12.1%	-9.1%	-7.6%	-6.7%	-4.4%				
2018/19	36,008	-27.9%	-27.1%	-24.5%	-23.2%	-22.6%	-20.6%	-18.5%			
2019/20	39,192	-22.5%	-21.6%	-18.8%	-17.3%	-16.7%	-14.4%	-12.3%	-12.4%		
2020/21	37,171	-27.4%	-26.6%	-23.8%	-22.2%	-21.8%	-19.7%	-17.9%	-21.4%	-16.9%	
2021/22	42,413	-18.3%	-17.2%	-14.0%	-12.0%	-11.6%	-9.1%	-7.4%	-11.2%	-10.4%	-8.7%

Values are non-coincident peaks

Table 4
Comparison of Winter Peak Forecasts to Actual Peaks and Forecast Variance

Finally, ***Table 5*** shows a comparison between the historical load factors (for 2012 through 2021), and the projected load factors (for 2022 through 2031), based on the summer peak. The summer peak was chosen for this calculation because it is less volatile than the winter peak, which fluctuates widely over the historical years because cold winters have occurred only sporadically. Both historical and forecasted load factors are similar in magnitude. Projected load factors are slightly lower than what has been reported historically, due to peak demand growing slightly faster than NEL[4].

FRCC LOAD FACTORS (Based on Summer Peak)			
Historical Year	**Load Factor**	**Forecasted Year**	**Load Factor**
2012	0.574	**2022**	0.561
2013	0.568	**2023**	0.559
2014	0.560	**2024**	0.559
2015	0.585	**2025**	0.560
2016	0.557	**2026**	0.558
2017	0.567	**2027**	0.557
2018	0.593	**2028**	0.557
2019	0.569	**2029**	0.555
2020	0.598	**2030**	0.554
2021	0.595	**2031**	0.553

Table 5
FRCC Load Factors

Forecasting models and methodologies used for developing energy sales and peak demand forecasts are delivering current projections that appear reasonable based on historical data and recent forecasts. The inputs and assumptions were also reasonable and appropriate given current trends. As a result of this evaluation, the FRCC LFWG concludes that the load forecast is suitable and reasonable for use in reliability assessment analyses.

8.0 FRCC Transmission

FRCC members and FRCC staff perform various annual transmission planning studies addressing the NERC TPL-001-4 (and its soon-to-be-effective revision, TPL-001-5) Transmission Planning Reliability Standard. These studies include near-term (years one through five), and longer-term (years six through ten) forecasted peak load conditions and certain additional system sensitivity conditions (e.g., extreme weather, off-peak conditions, spare equipment strategies). The studies include existing and planned Facilities within the FRCC Region, though the assumptions for the longer-term are more tenuous given the uncertainty of generation and transmission expansion plans that are still under review and the location and timing of the projected loads.

The most recent studies of the Bulk Electric System (BES) transmission system demonstrate the adequacy of the BES within the FRCC Region under Planning and Extreme events in NERC Reliability Standard TPL-001-4/5. The studies concluded that potential steady-state thermal and voltage performance violations can be resolved by operator intervention to meet the NERC TPL Standard after planned system adjustments and Corrective Action Plans are implemented as planned by FRCC members. The studies also found that Corrective Action Plans of FRCC members will resolve all short-circuit breaker duty screening exceptions. Finally, the studies show that the system is expected to perform within all TPL Standard stability performance criteria. Thus, based on the current study assumptions, there is no need for new regional infrastructure to support reliability other than the infrastructure that FRCC members already have planned.

9.0 FRCC Fuel Reliability

Long-term adequacy reviews consider the potential of natural gas supply or delivery disruptions on the long-term adequacy of FRCC resources to meet customer load. The FRCC has undertaken initiatives to increase coordination among natural gas pipeline operators and generators within the FRCC Area. The FRCC, through its Fuel Reliability Working Group (FRWG), provides the administrative oversight of a regional fuel reliability forum that assesses the interdependencies of fuel availability and electric reliability in the near-term.

Results of the most recent analysis indicate that risk to the reliability of the power system within the FRCC related to projected shorter-term gas delivery disruptions for normal winter peak loads can be mitigated through use of dual fuel units and increased fuel management coordination. Extreme winter loads could challenge generating capacity as well as the level of shorter-term gas delivery disruption mitigation available.

The *FRCC Generating Capacity Shortage Plan* distinguishes between generating capacity shortages caused by (1) abnormally high system loads or unavailable generating facilities or (2) inadequate fuel supply. The two types have distinct initiating events and require unique responses to ensure optimal state-wide communication and coordination to minimize impacts of shortages on the people of Florida. The procedure provides the FRCC Operating Committee (OC) a process to allow for proper communication and coordination between the FRCC Reliability Coordinator (RC) and the natural gas pipeline operators as necessary. In addition, the FRCC Operating Reliability Subcommittee (ORS), through its FRWG continues to periodically review and assess various aspects of the current fuel supply infrastructure in terms of reliability for generating capacity.

For capacity constraints due to inadequate fuel supply, the FRCC State Capacity Emergency Coordinator (SCEC), along with the FRCC RC, can assess FRCC RC Area fuel supply status by initiating Fuel Data Status reporting by FRCC Operating Entities (OEs). This process requires the FRCC OEs to report their actual and projected fuel availability, along with alternate fuel capabilities, to serve their projected system loads. This is typically provided by type of fuel and expressed in terms relative to forecast loads or generic terms of unit output, depending on the event initiating the reporting process. Data is aggregated at the FRCC level and is provided from an FRCC RC Area perspective to the RC, SCEC and governmental agencies as requested. Fuel Data Status reporting is typically performed when threats to FRCC RC Area fuel availability have been identified and the results of the reporting are quickly integrated into an enhanced FRCC daily capacity assessment process along with various other coordination protocols. These processes help improve the accuracy of the reliability assessments of the Region and ensure coordination to minimize impacts of FRCC RC Area fuel supply issues and/or disruptions to facilities and customers.

Currently, the expected percentage of generation capacity (MW) whose primary fuel is natural gas is projected to reach 65.3% by 2031. A similar long-term forecast projects coal-fired generation to account for 2.14% of capacity, nuclear generation for 10.85% and oil-fired generation for 2.9% of generation resources. About 18.2% of capacity generation will be from Renewables (Solar, Municipal Solid Waste, Landfill Gas, etc.), Inter-Regional interchange, and miscellaneous fuels.

Regarding the percentage of total electrical energy (GWh) provided by natural gas, the use of natural gas is currently projected to remain high through the next ten years with the projected percentage being 65% in 2031.

Currently, with no natural gas production or storage within Florida, three major pipelines deliver more than 90% of the natural gas to the FRCC RC Area. Existing and planned pipeline capacity within the Region supports the increasing gas generation requirements driven from new gas-fired generators being constructed over the next 10 years. In the event of a short-term failure of key elements of natural gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand on a short-term basis. However, additional coordination would be required in the event of a long-term failure of natural gas pipeline infrastructure.

FRCC OEs continue to utilize mitigation strategies to minimize the effects of short-term supply interruptions due to extreme weather during peak load conditions. These strategies include fuel storage, fuel supply and transportation diversity as well as alternate fuel capabilities. Absent long-term transportation outages, and based on current fuel diversity, alternate fuel capability and on-going coordination efforts, the FRCC does not anticipate any fuel transportation issues that will affect electric reliability during peak periods in the near-term.

10.0 FRCC Renewable Energy Resources

Nationally, the definition of renewable energy resources varies from state to state. While almost all states treat solar and wind as renewable resources, many states differ on the applicability of other forms of renewable resources such as municipal solid waste (MSW) facilities and some types of hydroelectric and waste heat from cogeneration facilities. The State of Florida has defined the term "Renewable Energy" in Florida Statute 366.91 as "electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat from sulfuric acid manufacturing operations, and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration." Furthermore, the term "Biomass" is defined as "a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts or products from agricultural and orchard crops, waste and co-products from livestock and poultry operations, waste and byproducts from food processing, urban wood waste, municipal solid waste (MSW), municipal liquid waste treatment operations, and landfill gas."

Twenty-seven States, Washington, D.C., and two territories have adopted a Renewable Portfolio Standard (RPS) and three states, and one territory have set renewable energy goals as of August 2021 [21]. Although the State of Florida does not have a Renewable Portfolio Standard (or a Clean Energy Standard), a portion of its energy is derived from renewable resources and a significant amount of energy, approximately 12%, is produced by emissions-free nuclear resources.

Total Renewable energy generation in 2021 for the FRCC Reliability Area was 10,208 GWh. Solar (84.2%), Biomass (5.8%), municipal solid waste (6.0%), and Landfill Gas (2.2%) provided the bulk of this 2021 renewable generation, as seen in ***Figure 7*** below.

Based on the utilities' TYSPs, renewable energy generation in the FRCC Reliability Area is projected to grow from 10,208 GWh in 2021 to 50,545 GWh by 2031 (4.1% of total NEL in 2021 to 18.3% of the NEL in 2031). Perhaps even more important is the increase in the contribution from solar: from 8,595 GWh in 2021 to 48,017 GWh in 2031 (2.5% of total NEL in 2021 to 14.4% of total NEL in 2031). ***Figure 8*** provides the projected values for 2031. FRCC and individual entities continue to monitor and evaluate penetration levels of renewable resources to ensure resource adequacy and system reliability.

One particular concern around the growth of utility-scale PV solar will be how it contributes to the firm peak calculation used in both reserve margin and LOLP analyses. Solar is typically given some percentage of its nameplate rating as a contribution to summer peaks; for summer, the amount varies and is determined by the individual utilities. This value varies from utility to utility as factors such as geographic location, technology

[21] https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

type and expected time of system peak can affect the firm capacity value; for winter, solar typically receives no firm capacity value. This firm capacity contribution from solar will continue to be monitored as solar becomes a larger and larger part of FRCC member company's resource mix and utilities continue to integrate largescale battery storage. Importantly, while solar is expected to contribute to traditional peak hours, times of day with high or persistent cooling load without sunlight must be carefully examined to ensure sufficient firm capacity in such hours over the longer-term planning horizon. The operational combination of energy storage and solar must also be analyzed with more depth to understand the extent to which future solar output shapes can be optimized to support reliability.

Renewable energy resources and their contribution to overall FRCC Reserve Margin continues to be evaluated as penetration of these resources increases year to year. Measuring traditional reserve margins over a seasonal peak hour, while highly beneficial, is anticipated to be subject to reduced applicability in the context of resource adequacy as the amount of intermittent generation synched to the FRCC system increases. Energy sufficiency across all hours of the day, among other resource adequacy metrics, must be developed to better capture and communicate the long-term adequacy position of the FRCC. FRCC Members and staff continue to work on defining and evolving the standard of practice for such calculations, beginning with a focus on readily available data.

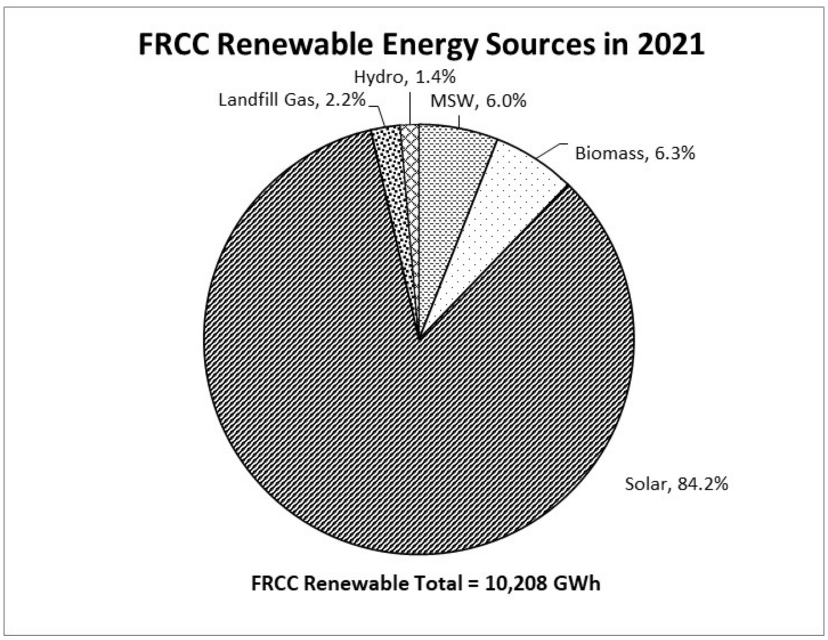

Figure 8
FRCC Renewable Energy Sources in 2021[22]

[22] This data is reflective of utility-scale installations and does not include the impacts of Distributed Energy Resources.

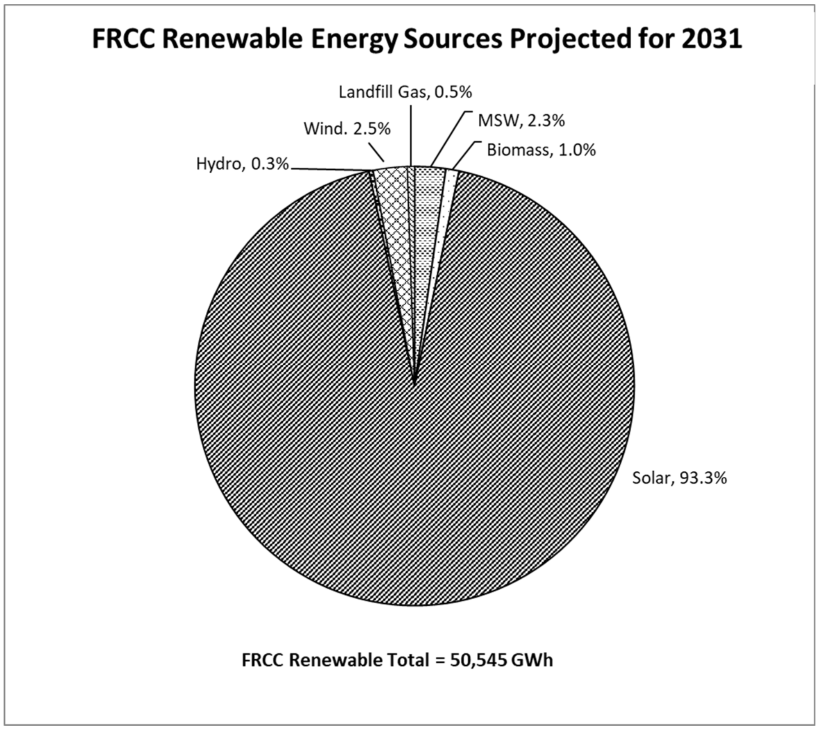

Figure 9
FRCC Renewable Energy Sources Projected for 2031

11.0 Battery Energy Storage in the FRCC Region

FRCC members continue to analyze additional opportunities to utilize battery storage systems as part of their resource portfolios. This includes combining battery storage with new or existing PV facilities or for other types of specific system support. FRCC members are considering batteries for a variety of purposes including, but not limited to contributing towards capacity, substation upgrade deferral, distribution line reconductoring deferral, power reliability improvement, frequency regulation, Volt/VAR support, backup power, energy capture, and peak load shaving.

FRCC members continue to gain experience with batteries and share experiences so that they will be better able to develop methodologies and protocols to properly account for battery contributions toward capacity, energy sufficiency and operational support as additional energy reliability assessments are performed in the future.

The FRCC Region currently has approximately 496 MW of firm summer capacity from battery storage and an additional 2,400 MW of firm summer capacity from battery storage facilities are planned through 2031. The FRCC Resource Subcommittee (RS) continues to analyze battery storage and its effect on resource planning.

12.0 References

12.1 ***2022 Regional Load & Resource Plan***

13.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
06/04/2022	1	New document	All

14.0 Disclaimer

The information, analysis, requirements and/or procedures described herein are not intended to be fully inclusive of all activities that may support compliance to a specific NERC Reliability Standard referenced or implied within the document. Nevertheless, it is the FRCC entities' and other users' responsibility to ensure the most recent version of this document is being used in conjunction with other applicable procedures, including, but not limited to, the applicable NERC Reliability Standards as they may be revised from time to time.

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FRCC
2021 Long Range Transmission Study Report – Regional Plan

FRCC-MS-PL-401*

Version: 1

3001 North Rocky Point Drive East, Suite 410
Tampa, Florida 33607-8410
(813) 289-5644 - Phone
(813) 289-5646 – Fax
www.frcc.com

This version of the Long-Range Transmission Study Report includes non-BES Facilities which may be outside the scope of applicable NERC Reliability Standards.

Refer to the *2021 Long Range Transmission Study Report for NERC Reliability Standards (FRCC-MS-PL-402)* for the BES only version.

**CEII Information Removed*

Classification: CEII

The original signatures are maintained on file.

TITLE	NAME	DATE
Version Author	Denise Lam	09/09/2021
Document Review Authority	TTS	10/26/2021
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Table of Contents Page

1.0 Purpose

The mission of the FRCC is to ensure that the Region's BES and its interconnections with adjacent Planning Coordinators are reliable, adequate, and secure. In addition, the performance of non-BES transmission facilities is evaluated to ensure reliability of the entire transmission system is maintained under normal, single, and multiple contingency events.

NERC Transmission Planning (TPL) Reliability Standard TPL-001-4 applies to those transmission Facilities that meet the definition of NERC BES elements, generally those operated at 100 kV and above and transformers with a low-side voltage greater than 100 kV. Although not required by the NERC TPL-001-4 Reliability Standard, non-BES transmission facilities are included in this study, in accordance with the FRCC Regional Transmission Planning Process. Including the non-BES transmission system improves the Transmission Planners' (TPs) understanding of system performance and the effectiveness of plans based on this *2021 Long Range Transmission Study Report* (Study). The FRCC performs this Planning Assessment, as documented in this 2021 Study by conducting regional activities related to planning, operations, and coordinating activities with intraregional and interregional entities to ensure transmission reliability in the FRCC Region.

FRCC TPs and IRPCs annually perform an assessment of their portion of the FRCC transmission system and their ties with adjacent IRPCs and TPs for the Near-Term and Long-Term with the assistance of FRCC staff. These assessments include planned system adjustments, Corrective Action Plans (CAPs), Non-BES Capital Development Projects (CDPs) as needed, demonstrate the adequacy of the BES within the FRCC Region.

2.0 Terms and Definitions

2.1 See NERC's *Glossary of Terms Used in NERC Reliability Standards* for definitions of capitalized terms not defined in this section.

2.2 Individual Registered Planning Coordinators (IRPC)

Individual Registered Planning Coordinators means all Planning Coordinators within FRCC, absent the FRCC Planning Coordinator, that are registered with NERC and have executed Coordinated Functional Registration between the registered entity and the FRCC for all Reliability Standards applicable to a Planning Coordinator.

2.3 FRCC Planning Coordinator (PC) / FRCC Planning Authority (PA)

FRCC Planning Coordinator or FRCC Planning Authority means the FRCC Planning Committee as the registered Planning Coordinator responsible for demonstrating compliance with those respective requirements and sub-requirements as identified within this document and within the Coordinated Functional Registration.

2.4 FRCC Region

.FRCC Region includes the Planning Authority (PA) boundaries of the individual PAs (FRCC PAs) who are part of a NERC Coordinated Functional Registration (CFR) with the FRCC PA.

2.5 Capital Development Projects (CDPs)

Projects that are utilized to solve non-BES overloads

2.6 System Models

System Models include steady state and short circuit databank cases developed with the data collected from each of the applicable entities in accordance with NERC Reliability Standard MOD-032-1.

3.0 Responsibilities

3.1 FRCC Transmission Technical Subcommittee (TTS)

The FRCC Transmission Technical Subcommittee (TTS) is responsible for the document's final review before submitting the document for approval.

3.2 FRCC Stability Analysis Subcommittee (SAS)

Contingencies that could not be solved in the steady state would be supplied to the FRCC's Stability Analysis Subcommittee (SAS) for further analysis.

3.3 Document Review Authority

The TTS is responsible for reviewing this assessment.

3.4 Document Owner/Approval Authority

The FRCC Planning Committee (PC) and the Board of Directors (BOD) are responsible for approving the document.

4.0 Assessment/Study

4.1 Executive Summary

The Florida Reliability Coordinating Council, Inc. (FRCC) Transmission Technical Subcommittee (TTS) has completed the Region's annual Near-Term Transmission Planning Horizon (Near-Term) and Long-Term Transmission Planning Horizon (Long-Term) steady-state study representing study years 2022 through 2032. This report represents the TTS's compilation and analysis of Bulk Electric System (BES) performance within the FRCC Region in accordance with *Table 1: Steady State Planning Events and Steady State Extreme Events* of the NERC Reliability Standard TPL-001-4 (see Appendix D), and the *2021 TTS Steady State Planning Study Scoping Worksheet* (FRCC-MS-PL-375). In addition, the performance of non-BES transmission facilities is evaluated to ensure reliability of the transmission system in the FRCC Region is maintained under normal, single, and multiple contingency events. Finally, this analysis also assessed certain facilities that will become part of the FRCC Region in Summer 2022 (Gulf Power/Florida Power and Light-West Area), though they are outside of the FRCC Region's planning responsibility as of today. Background information, methodology, analysis, planned projects, and planned system adjustments are contained within this report.

This study includes a steady-state evaluation of a series of load flow cases (models) representing the transmission system at various points in time to aid in demonstrating that the transmission system within the FRCC Region remains adequate, secure, and reliable throughout the ten-year planning horizon. The models used for this study include existing and planned facilities for the Near-Term (2022 - 2027) and Long-Term (2028 - 2032) planning horizons. All transmission facilities rated 69 kV and above are represented in the FRCC system models. The steady-state analysis also includes a sensitivity analysis to demonstrate the impact of changes to the base assumptions used in the model.

This study also includes a short circuit analysis of the Near-Term Transmission Planning Horizon to determine if any circuit breakers will exceed their interrupting capability for faults that they will be expected to interrupt. The short circuit model for this analysis was performed on the summer 2024 peak case.

The results of this study demonstrate that the FRCC Region is planned and can be operated such that, with all transmission facilities in service (category P0) and with normal (pre-contingency) operating procedures in effect, the transmission system can supply projected customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands under the conditions defined in Category P0 of Table 1 of NERC Reliability Standard TPL-001-4.

The results of single and multiple contingency (Categories P1-P7) planning events identified portions of the transmission system that require planned system adjustments in order to respond as prescribed in Table 1 of NERC Reliability Standard TPL-001-4. The planned system adjustments ensure the transmission system within FRCC Region is planned such that it meets all performance requirements, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category P1-P7 of Table 1 of NERC Reliability Standard TPL-001-4. Together, the planned facilities and remedial actions ensure BES system performance as required by the NERC Reliability Standard TPL-001-4, as well as reliable performance of the non-BES transmission facilities.

4.2 Methodology

System Model

The Study was performed utilizing the FRCC Transmission Technical Subcommittee's (TTS's) steady state and short circuit databank cases (System Models). The System Models are developed with the data collected from each of the applicable entities in accordance with NERC Reliability Standard MOD-032-1 and as documented in the *FRCC Steady-State Data for Power System Modeling and Analysis Procedure* (FRCC-MS-PL-109) and the *FRCC Short-Circuit Data for Power System Modeling and Analysis Procedure* (FRCC-MS-PL-063). These manuals outline what data will be supplied by each of the applicable entities and the manner in which the data shall be provided, i.e., existing Facilities, new planned Facilities and changes to existing Facilities, the real and reactive load forecast, known commitments for firm transmission service and interchange and all supply and demand side resources required to serve load. See Appendix A for additional details on study parameters and methodology. In addition, the System Models were updated to incorporate all known generator and transmission facility outages as reported in the Florida Transmission Management System (FTMS) in accordance with the following:

Planned Outage Philosophy

- Summer window: June 1st – August 31st
- Winter window: December 15th – March 15th

- FTMS query date is: 6/1/2021
- Outage must be more than 6 months in duration
- Outage extends into the window will be modeled

No transmission planned outage and no generator planned outages in the planning horizon were modeled in the study cases. This did not require coordination with the FRCC Reliability Coordinator to develop a joint solution. See Exhibit 2 for the generator and line outage summary.

Although not yet enforceable, outages were assessed in accordance with the recent *FRCC TPL-001-5 Outage Selection Rationale*, *FRCC-MS-PL-354*procedure, which determines if known outages less than six months should be included in the study. There were no outages identified to be included in this study per *FRCC TPL-001-5 Outage Selection Rationale, FRCC-MS-PL-354* procedure.

Case Selection

The Study covers both Near-Term and Long-Term portions of the planning horizon. The Near-Term portion examines planning years one through five and was represented by performing the assessment for year two (winter peak 2023/2024 and summer peak 2024) and year five (winter peak 2026/2027 and summer peak 2027). The Long-Term planning horizon was represented by performing the assessment for year seven (winter peak 2028/2029 and summer peak 2029). These cases represent the mid-range of the Long-Term planning horizon and allow the TP sufficient time to identify potential projects which may require longer lead-time for implementation and identification of specific planned system adjustments. The identification of preliminary proposed projects and the plan to study alternatives can also be acceptable CAPs for the Long-Term horizon.

The Near-Term portion of the Study includes a system off-peak load scenario for year two (summer 2024). The off-peak model includes a 60% and 80% of summer peak load level[1]. The off-peak load conditions were also selected to represent the typical operating range of load levels and variations in corresponding generation dispatch and voltage support experienced within the FRCC Region.

Case Assessment

All FRCC System Models, representative of economic peak and off-peak load conditions, were first evaluated against category P0 to ensure that all cases are within their applicable rating. The base cases were then assessed for possible Rate C exceptions (See Attachment O for more detail). Rate C is an upper limit screening criteria proxy rating that can be calculated based on a variety of conditions (pre-load, time, etc.) that allow a higher rating to be available for a Facility for a specified time limit. The FRCC System Models were assessed by running contingencies P1, P2, P4, and P7 against Rate C. The entities addressed screening exceptions by using one of four remedial methods: pre-contingency switching, pre-contingency dispatch adjustment, establishment and documentation of a higher Rate C, or an automatic operating action scheme (i.e., SPS, UVLS, etc.). Non-BES facilities with potential Rate C exceptions are monitored to avoid potentially impacting the BES. The Non-BES facilities with Rate C exceptions can be found in Attachment O.

[1] Representative of an early morning Summer Peak day where load is at selected load level and Summer Peak will be reached (i.e., shoulder hour)

Sensitivities

Sensitivity cases were developed from the FRCC System Models analyzed and developed above (post Rate C screening) and based upon the year and season selected by the TTS to assess the impact of changes to the basic assumptions used in the models. Sensitivities performed were for two seasons of the Near-Term and one season of the Long-Term, as detailed below. Contingency events exceeding the respective entities' thermal and/or voltage screening criteria were reviewed by the entities. Planned system adjustments were provided by entities to resolve potential screening criteria exceptions (see Attachment J).

Sensitivities assessed:

- **2023/2024W Peak – Severe Winter Loads**
  Scenario: Winter peak much higher than forecasted
  - 20% above forecasted winter peak
  - Solar dispatched at 0% of nameplate capacity (MW_{AC})
- **2024S Peak – Impending Storm Dispatch**
  Scenario: Plants on the west coast will be shutdown ahead of time for a hypothetical incoming storm
  - The following units were turned off: Anclote 1 & 2, Bartow ST4, Hines CT1B & CT2B & CT4B, Manatee CC, MGS, HPS, Purdom, Big Bend CT4, Bayside 1ST & 2ST
  - The following units were reduced: CR4 (52%), Hines ST1 & ST2 (50%), FPL Solar (1/3 of FPL solar reduced to 30% output), TECO solar (30% output)
  - The following unit was turned on: Manatee Battery
- **2024S 60% Peak – Dramatic Increase in Distributed Solar**
  Scenario: Assume distributed solar will be more than twice the amount forecasted by 2024S
  - 10% of distribution load served by distributed solar during 60% Peak[2]
  - Solar PV dispatched at 100% of nameplate capacity (MW_{AC})
- **2026/2027W – Battery Charging at Night Prior to a Winter Peak**
  Scenario: In preparation for the winter peak, batteries are charging overnight (3-4 hours before winter peak)
  - Load scaled down to 70% to match with overnight scenario
  - 10 MW load added to every solar site that are part of the entity's Ten Year Site Plan (TYSP)
    - If there is a batteries (existing or planned) at the solar site, the load amount added to the site may be increased
  - Solar PV dispatched at 0% of nameplate capacity (MW_{AC})

[2] Representative of a Fall/Spring day where load will reach 60% of a Summer Peak day (i.e., shoulder month)

- **2027S – Minimum Solar Output Conditions with Expected Retirements Modeled**
  Scenario: Higher solar penetration in a later year case, but conditions are not favorable to solar due to high clouds or haze and expected retirements modeled
  - Solar PV dispatched at 20% of nameplate capacity (MW_{AC}) unless battery storage can increase output
  - If applicable, rollover rights not available for the transmission service

Spare Equipment Strategy

The study incorporates all IRPC's spare equipment strategy. The spare equipment strategy consists of a collected list of facilities that have a lead time of one year or more. The study is performed for categories P0, P1, and P2 events. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the entities. Planned system adjustments are provided by entities to resolve potential screening criteria exceptions (see Attachment K).

An initial screening process simulates the simultaneous outage of each spare equipment strategy plus each P1 and P2 contingency event. Spare equipment strategy scenarios are flagged for further assessment if either criterion is met:

- Spare equipment strategy/contingency pair results in a Rate B overload where the overload is greater than 3% (of Rate B) as compared to the base case and has the highest Rate B overload in each unique contingency/monitored element pair or
- Spare equipment strategy/contingency pair results in a voltage violation where there is a difference of at least 2% compared to the base case and has the highest voltage difference in each unique contingency/monitored element pair

Spare equipment strategy flagged for further analysis included:

Equipment Strategy	23w	24s	26w	27s	28w	29s
EqptSt:DEF::Twin River PV GSU		x				
EqptSt:FMPA::KIS-CI3 GSU	x					
EqptSt:FMPA::KIS-CI4 GSU	x	x	x	x	x	x
EqptSt:FMPA::TCEC-CC GSU	x					
EqptSt:GPC:115:Crist 6 GSU			x			x
EqptSt:GPC:230:Crist 7 GSU	x					x
EqptSt:GPC:230:Smith 3A GSU			x			
EqptSt:GPC:230:Smith 3B GSU		x				
EqptSt:GVL::JRK CT#4	x		x		x	
EqptSt:JEA:138/20:Northside 1	x	x	x	x	x	x
EqptSt:JEA:230/18:Northside 3				x	x	x
EqptSt:LAK:230/20:MP5-CT GSU	x		x		x	
EqptSt:OUC::Harmony PV GSU		x				
EqptSt:OUC::Stanton 1 GSU					x	
EqptSt:OUC::Stanton A GSU				x		x
EqptSt:OUC::Stanton B GSU					x	
EqptSt:OUC::Taylor Creek PV GSU		x				

EqptSt:SECI::Black Creek N_TR	x		x	x	x	x
EqptSt:SECI::Black Creek S2_TR	x	x	x	x	x	x
EqptSt:SECI::MGS CT1			x		x	
EqptSt:TAL::Hopkins_CT_TR					x	
EqptSt:TAL::Hopkins_ST_TR						x
EqptSt:TAL::Sub7 TR2	x					
EqptSt:TEC::Bayside CT5					x	
EqptSt:TEC::Polk CT1			x			
EqptSt:TEC::Polk CT2					x	

Each spare equipment strategy that was flagged for further assessment is then simulated against each P1 and P2 contingency with an option to apply system adjustments after the first contingency. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the entities. Planned system adjustments are provided by entities to resolve potential screening criteria exceptions (see Attachment K).

Short Circuit

A near-term summer short circuit case was developed from year two of the FRCC System Models for the Near-Term planning horizon (2024s) for IRPCs to perform the short circuit analysis for their portion of BES. The IRPCs performed the analysis and compared the results of their analysis against their respective breaker fault duty data for each of the respective stations and determined whether circuit breakers had the interrupting capability for faults that they will be expected to interrupt. The IRPCs, based on their breaker replacement methodology, then supplied those buses/locations where maximum fault current exceeded or will exceed the breaker fault duty at that respective location. The IRPCs then provided a CAP or CDP listing the system deficiencies and the associated actions needed to achieve required system performance, these actions will be reviewed annually, through subsequent annual Long Range Studies. See Attachment N for Short Circuit analysis and assumptions.

4.3 Assumptions

NERC Reliability Standard TPL-001-4 requires that the BES be planned such that it will remain stable, within each respective entity's applicable thermal ratings and voltage criteria, without cascading outages and without controlled loss of demand or curtailment of firm power transfers during Category P0, P1, P2-1, & P3 conditions. Categories P2-2, P2-3, P2-4, P4, P5, P6, & P7 permit planned/ controlled loss of non-consequential load or curtailment of Firm power transfers. Load flow study cases include the planned (including maintenance) outage of BES elements expected to be out of service during the time period under study. For more information, refer to the *TPL-001-4 Contingency Selection Rationale for Long Range Transmission Study* (FRCC-MS-PL-319) in Exhibit 3.

Category P0 Analysis

For Category P0 conditions, all transmission facilities rated 69 kV and above were monitored and compared to each respective entity's applicable thermal rating and/or voltage screening criteria throughout all study cases. Any facility loadings exceeding the applicable thermal rating and/or voltage screening criteria were reviewed by the respective entities and case adjustments were provided and reflected in the study cases for the remainder of the analyses (see Attachment A). This includes modeling established normal (pre-contingency) operating procedures in the base case.

Category P1 and P2-1 Analysis

For Categories P1 and P2-1 events, all transmission facilities rated 69 kV and above were singularly removed from service in all study cases. Contingency events that exceeded respective entities' applicable thermal ratings and/or voltage screening criteria were reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were then provided by the entities to resolve potential screening criteria exceptions. This analysis allows TPs to ensure that future system performance meets Category P1 and P2-1 event requirements for the BES, and acceptable performance criteria for the non-BES facilities (see Attachment B).

Category P1 and P2-1 Simulation Study Methodology

Category P1 events specify single event outages of transmission circuit, transformers, generators, or shunt device in which there is a normally-cleared three phase or single line to ground fault. Normal fault clearing assumes operation of the protection systems as designed. Category P2-1 events specify opening of a line section without a fault. In accordance with Requirement R3.3.2, this analysis included the effects of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. Additionally, in accordance with Requirement R3.3.1, this analysis simulated the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without operator intervention.

Category P2-2 through P7 Analysis Selection

Categories P2-2 through P7 of Table 1 of NERC Reliability Standard TPL-001-4 were used to determine system performance under multiple contingency scenarios that would identify the more severe system impacts on the FRCC BES. See Appendix C for a discussion on the choice of multiple contingencies for inclusion in the Study.

Category P2-2 (Bus Section failure) Analysis: Bus Section failure events that result in the loss of two or more transmission system elements 100 kV and above are simulated in all Near-Term and Long-Term planning horizon cases used for the Study. Contingency events that exceed the respective entities' thermal and/or voltage screening criteria were reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment C).

Category P2-3 & P2-4 (Breaker failure) Analysis: Breaker failure events that result in the loss of two or more transmission system elements 100 kV and above are simulated in all Near-Term and Long-Term planning horizon cases used for the Study. Contingency events that exceed the respective entities' thermal and/or voltage screening criteria were reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment D).

Category P3 (Generator) Analysis: Multiple contingency events that represent the loss of one selected generating unit followed by system adjustments and the subsequent loss of one transmission element rated 69 kV and above or an additional generating unit were evaluated. Unit out cases were created through an initial screening process that simulated the simultaneous outage of each generating unit greater than or equal to 100 MW plus each P1 contingency discussed above. Unit out cases identified through the screening criteria analysis (as described in the *TPL-001-4 Contingency Selection Rationale for Long Range Transmission Stud*y (FRCC-MS-PL-319) found in Exhibit 3) were then further assessed. Additionally, TTS members were provided an opportunity to add to the list of unit out cases based on their review. The units included in the further analysis were:

Company	Unit Out	23w	24s	26w	27s	28w	29s
DEF	CITCC1	x				x	
DEF	CITCC2	x	x	x		x	
DEF	OSPREYCC			x		x	
FMPA	CI4CC		x		x		
FPL	DEC_CC		x		x		x
FPL	FT.MYRCTAB_ST	x		x		x	
FPL	FT.MYRCTCD_ST					x	
FPL	FT.MYRCTEF_ST				x	x	
FPL	MN3_CC	x	x	x	x	x	x
FPL	PEE_CC				x		x
FPL	PTP5_CC		x		x		x
FPL	RIVE_CC		x		x		x
FPL	TP3				x		x
GVL	DH2	x	x	x	x	x	
JEA	North3	x	x				
JEA	BrandyBranchCC	x	x				
LAK	MSU5_CC	x					
OUC	StantonA		x		x		
SECI	SEM1	x	x	x	x	x	x
TAL	Purdom8	x					x
TAL	HopkinsCC		x			x	
TEC	BIGBENDCC1			x		x	
TEC	POLKCC2			x		x	

Red Font: additional cases requested by TTS to be included for further assessment

Unit out cases were then built by removing each unit in the list from service and modeling system adjustments as instructed by TTS members. Each unit out case was then simulated against each P1 contingency and those that exceeded respective entities' applicable thermal and/or voltage screening criteria are reviewed by the entities for all Near-Term and Long-Term planning horizon cases. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment E).

Category P4 (Fault plus stuck breaker) Analysis: A stuck breaker (non-Bus-tie Breaker) attempting to clear a fault that results in the loss of two or more transmission system elements 100 kV and above are simulated in all Near-Term and Long-Term planning horizon cases used for the Study. Contingency events that exceeds respective entities' applicable thermal and/or voltage screening criteria were reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment F).

Category P5 (Fault plus relay failure to operate) Analysis: A delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed for more transmission system elements 100 kV and above are simulated in all Near-Term and Long-Term planning horizon cases used for the Study. Contingency events that exceed respective entities' thermal and/or voltage screening criteria were reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment G).

Although not yet required by the current NERC TPL Standard, the study included contingencies to simulate delayed fault clearing due to the failure of a non-redundant component of a protection system (other than a relay). Results of these contingencies are contained in Attachment P for information only and do not include planned system adjustments, CAPS, or CDPs.

Category P6 (Two Overlapping Singles) Analysis: This category covers events that result in the loss of two independent transmission elements. All possible line combinations rated 100 kV and above were evaluated. Results showing line loadings greater than 100% of Rate C or bus voltages less than 0.88 per unit were identified as candidates for further evaluation. Candidate double contingencies that did not exceed thermal and/or voltage screening criteria when evaluated as single contingencies required a remedy by the entity for the double contingency. Remaining candidate double contingencies that exceeded thermal and/or voltage screening criteria, when evaluated as single contingencies, were modeled individually with the necessary system reconfiguration prior to the subsequent contingency. The results of the double contingencies with the system reconfiguration were reviewed by the entities and planned system adjustments and, if needed, CAPs or CDPs were developed to address any resultant thermal and/or voltage potential screening criteria exceptions (see Attachment H).

Category P7 (Common Structure) Analysis: Events resulting in the loss of two or more circuits of a multiple circuit tower line greater than one mile in length and rated 100 kV and above are simulated in all Near-Term and Long-Term planning horizon cases used for the Study. Contingency events that exceed the respective entities applicable thermal and/or voltage screening criteria are reviewed by the entities. Planned system adjustments and, if needed, CAPs or CDPs were provided by entities to resolve potential screening criteria exceptions (see Attachment I).

Coordinated Planned System Adjustments

Contingencies that result in exceedance of the respective entities applicable thermal loading and/or voltage screening criteria exceptions where the planned system adjustment requires the involvement of the transmission assets of two or more entities required coordinated planned system adjustments. The entities discussed various options, including remedial control, switching of transmission assets and/or coordinated generation re-dispatch, in order to develop coordinated planned system adjustments and, if needed, CAPs or CDPs that addressed the transmission concerns.

Emergency Ratings and System Operating Limits

In accordance with TPL-001-4, FAC-010, and FAC-014, the study participants reviewed the simulation results to ensure that Facilities stayed within their applicable ratings and system operating limits. In addition, specific voltage screening criteria (from applicable NPIRs) were applied to busses where nuclear units are interconnected to ensure that the transmission system parameters and limits at nuclear Facilities are met. This study looks at future conditions and participants to ensure that the system response to the events, combined with their corrective plans, will not cause facilities to exceed their applicable ratings. These applicable ratings may include emergency ratings that are only applicable for short periods of time to allow for necessary operating steps.

Corrective Action Plan and Non-BES Capital Development Projects

During the performance of this study, as system criteria exceptions were identified, the entity with the facility rating criteria exception was responsible to resolve the criteria exception. Such entities provided mitigation plans addressing each criteria exception. Criteria exceptions that could not be resolved by operational planned system adjustments required the development of a CAP or CDP addressing how the performance requirements will be met. A CAP or CDP will be reviewed annually for continued validity through the Annual Study process. A CAP or CDP was only required if the entity did not identify a planned system adjustment that resolved the exception. Additionally, CAPs or CDPs are not required to be developed solely to meet performance requirements of a single sensitivity case. Any system criteria exceptions that were identified on multiple sensitivity cases and could not be resolved by planned system adjustments, required the entity to resolve the issues and provide a mitigation plan (see Attachment M).

4.4 Results and Observations

The results of this Study of normal, single, and multiple contingency events within the FRCC Region demonstrate that the transmission system is planned to meet the NERC Reliability Standards. Although the NERC Reliability Standard TPL-001-4 apply to the BES, the FRCC Region also assessed non-BES facilities, as outlined in the FRCC Planning Process, for reliability. The detailed results of this Study are discussed below.

The Study shows that for Category P0 through P7 events, the performance of the transmission system is adequate and in compliance with steady-state and short circuit portions of the NERC Transmission Planning Standards for the Near-Term and Long-Term planning horizons (see Attachments A – I).

Based upon a review of the Study results, the results of the Category P6 events can be mitigated by making operational adjustments to the power system to be ready for the next event in order to meet the requirements of the NERC Reliability Standard TPL-001-4 (see Attachment H).

The Study for the Long-Term planning horizon identifies any possible emerging concerns, monitors known concerns, monitors the effects of planned projects and identifies major projects that may require long lead-times. There were no instances identified of Non-Consequential Load Loss or curtailment of Firm Transmission Service beyond the control of an IRPC that prevent the implementation of a CAP or CDP in the required timeframe.

Sensitivity

The Study also demonstrates the performance of the system, under the defined sensitivities, is adequate and in compliance with the NERC Transmission Planning Standards (see Attachment J).

Spare Equipment

The Study demonstrates for category P0, P1, and P2 events performed on the models incorporating each IRPC's spare equipment strategy is adequate and in compliance with the NERC Transmission Planning Standards (see Attachment K).

Extreme Events

The Study evaluated the extreme events in Table 1 of the NERC Reliability Standard TPL-001-4 that each IRPC determined would be expected to produce the more severe system impacts in each IRPC's system. A rationale for the extreme events chosen for study can be found in the *TPL-001-4 Contingency Selection Rationale for Long Range Transmission Study* (FRCC-MS-PL-319) in Exhibit 3. The results were analyzed by each IRPC to determine if any cascading is possible, any event that resulted in cascading was evaluated for possible actions designed to reduce the likelihood or mitigate the impacts of the event (See Attachment L). Contingencies that could not be solved in the steady state were supplied to the FRCC's Stability Analysis Subcommittee (SAS) for further analysis.

Short Circuit

The Short circuit analysis performed by each IRPC for the near-term planning horizon (2024s) demonstrated that most circuit breakers had the interrupting capability for fault that they will be expected to interrupt. For those that were identified as over-dutied, a CAP or CDPs was developed (see Attachment N).

Inter-Regional Reliability Assessment

The results for normal, single, and multiple contingency events for facilities within the FRCC Region show no performance exceptions to the criteria of the NERC Reliability Standard TPL-001-4 within Southern Company. Additionally, no contingency events from identified facilities within the Southern Company (five buses deep in Southern Company system) exceeded the performance criteria of the NERC Reliability Standard TPL-001-4 within the FRCC Region.

4.5 Conclusion

The Study of the BES and non-BES transmission system, including existing and planned facilities within the FRCC Region, concludes that potential thermal and voltage screening criteria exceptions can be resolved by operator intervention meeting NERC Reliability Standard TPL-001-4, CAPs, or CDPs. These assessments, which include planned system adjustments, CAPs, and CDPs as needed, demonstrate the adequacy of the BES within the FRCC Region under Category P0 through P7 events.

5.0 Document Distribution/Notification Requirements

5.1 Distribution/Notification Timeframe

This document will be distributed within 5 business days of approval to the FRCC PC, FRCC TTS, and FRCC SAS.

5.2 NERC Required Distribution/Notification List

None

5.3 Additional Distribution/Notification List

5.3.1 FRCC PC

5.3.2 FRCC TTS

5.3.3 FRCC SAS

6.0 References

6.1 FRCC Steady-State Data for Power System Modeling and Analysis Procedure (FRCC-MS-PL-109)

6.2 FRCC Short-Circuit Data for Power System Modeling and Analysis Procedure (FRCC-MS-PL-063)

6.3 2021 TTS Steady State Planning Study Scoping Worksheet (FRCC-MS-PL-375)

6.4 NERC Reliability Standard TPL-001-4: Transmission System Planning Performance Requirements

6.5 NERC Reliability Standard MOD-032-1: Data for Power System Modeling and Analysis

6.6 NERC Reliability Standard IRO-017-1: Outage Coordination

6.7 TPL-001-4 Contingency Selection Rationale for Long Range Transmission Study (FRCC-MS-PL-319)

7.0 Attachments / Appendices / Exhibits

7.1 Attachment A: Planned System Adjustments for P0 Events

7.2 Attachment B: Planned System Adjustments for P1 and P2-1 Events

7.3 Attachment C: Planned System Adjustments for P2-2 Events

7.4 Attachment D: Planned System Adjustments for P2-3 and P2-4 Events

7.5 Attachment E: Planned System Adjustments for P3 Events

7.6 Attachment F: Planned System Adjustments for P4 Events

7.7 Attachment G: Planned System Adjustments for P5 Events

7.8 Attachment H: Planned System Adjustments for P6 Events

7.9 Attachment I: Planned System Adjustments for P7 Events

7.10 Attachment J: Sensitivity Results

7.11 Attachment K: Spare Equipment Results

7.12 Attachment L: Extreme Event Results

7.13 Attachment M: Corrective Action Plan (CAPs) and Capital Development Projects (CDPs)

7.14 Attachment N: Short Circuit Analysis and Assumptions

7.15 Attachment O: Rate C Screening

7.16 Attachment P: TPL-001-5 P5 Events

7.17 Appendix A: Study Parameters and Methodology Summation

7.18 Appendix B: Rate C Screening Methodology

7.19 Appendix C: NERC Multiple Contingency Event Guidelines for FRCC BES

7.20 Appendix D: NERC Reliability Standard TPL-001-4 Table 1 Reference

7.21 Appendix E: List of Pre-Contingency Switching

7.22 Appendix F: List of Participants

7.23 Exhibit 1: Short List of Regional Projects

7.24 Exhibit 2: Generator and Transmission Facility Outages

7.25 Exhibit 3: TPL-001-4 Contingency Selection Rationale for Long Range Transmission Study (FRCC-MS-PL-319)

8.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
11/02/2021	1	New Study	All

9.0 Disclaimer

The information, analysis, requirements and/or procedures described herein are not intended to be fully inclusive of all activities that may support compliance to a specific NERC Reliability Standard referenced or implied within the document. Nevertheless, it is the FRCC entities' and other users' responsibility to ensure the most recent version of this document is being used in conjunction with other applicable procedures, including, but not limited to, the applicable NERC Reliability Standards as they may be revised from time to time.

The use of this information in any manner constitutes an agreement to hold harmless and indemnify FRCC and FRCC Member Systems, and FRCC Staff, FRCC Committees and FRCC Member Employees from all claims of any damages. In no event shall FRCC and FRCC Member Systems, and FRCC Staff and FRCC Member Employees be liable for actual, indirect, special or consequential damages in connection with the use of this information.

Attachments A – P

Pages contain CEII information and are not included

Appendix A- Study Parameters and Methodology Summation

A.1 - Study Parameters

- Steady-state load conditions for summer 2023, 2024 (peak, 80%, 60%), 2025, 2026, 2027, 2029 and winter 2022/2023, 2023/2024, 2024/2025, 2025/2026, 2026/2027, 2028/2029 as represented in the FRCC FRCC system model.
- Generation and load are represented in MW and MVAr in all study cases.
- Photo Voltaic (PVs) PMAX is modeled at their nameplate capacity (MW_{AC}) and dispatched at 75% of their respective PMAX for the summer peak load scenario unless historical operational data or other considerations justify a different value (e.g. battery storage). For the 60% and 80% off-peak scenario, PV is dispatched at 100% of their respective PMAX. For winter peak, the PMAX is set to zero (0) unless battery storage justifies a different value.
- Screening of the thermal limit rating is 100% of Rate A for Normal [N] steady-state analysis.
- Screening of the thermal limit rating is 100% of Rate B for Contingency [N-1], & [N-2] steady-state analysis, except for Category P6. Category P6 Line analysis includes a screening of the thermal limit rating of 100% of Rate C.
- The criteria used to screen under/over voltage conditions are applicable to entities' criteria. This is to ensure that adequate Reactive Power resources are available to meet system performance requirements. Individual accepted company voltage criteria may be outside of the screening criteria range.
- Generators are forced to control the voltage of the low-side bus to simulate actual conditions.
- System models represent:
    - Existing Facilities. All transmission facilities and generating units are available in the study cases except those forecasted to be out during the time period under study. For 'N' or normal (pre-contingency) condition scenarios: all transmission facilities are in service and have normal (pre-contingency) operating procedures in effect.
    - Known outage(s) of generation or Transmission Facility(ies) with a duration

      of at least six months.
    - New planned Facilities and changes to existing Facilities
    - Real and reactive Load forecasts
        - Winter seasonal peaks have lower reactive demands then the summer seasonal peaks due to less use of heat pump cycles and greater use of strip heating.
        - The models for off-peak cases (80% & 60%) utilize system power factors consistent with the summer season.

      Known commitments for Firm Transmission Service and Interchange. All projected contracted Firm (non-recallable reserved) transmission services are included in the case interchange schedules as specified by the parties engaged in each transaction.
    - Resources (supply or demand side) required for Load

- Incorporates the applicable Nuclear Plant Interface Requirements (NPIR) provided by transmission entities responsible for providing services related to NPIRs.
- Simulated the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each contingency without operator intervention. To simulate such removal of Protection System and other automatic controls, the contingencies are defined in contingencies that are supplied by the TTS members. When a contingency is modeled for which an existing RAS exists and that contingency leads to overloads, the overload is flagged and sent to the RAS owner. (The contingency lists or software used for this study did not have RAS hardcoded into the initial simulation.) The RAS owner will model RAS to verify that the overload is mitigated by the RAS.
- Simulated tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Generator ride through is implicitly modeled by flagging voltage deviations outside of acceptable voltage ride-through capability limits. These limits are defined by Reliability Standard PRC-024-2 Attachment 2, and they generally require generators to ride through voltages above 0.90 per unit and less than 1.10 per unit (at the point of interconnection or the transmission, high voltage, side of the generator step-up or collector transformer). Each entity has set the voltage monitoring criteria for its buses in the simulation monitoring (".mon") files to be equal to or more stringent than this level.
- Simulated tripping of Transmission elements where relay loadability limits are exceeded. Relay loadability limits are implicitly evaluated by monitoring the Rate C of facilities. Rate C is always less than or equal to the Facility's relay loadability. See Appendix B for a detailed description of the Rate C screening process and Attachment O for the results of the process.
- Simulated the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. Phase-shifting transformers are not applicable due to the absence of such equipment within the FRCC Region. Load tap changers and switched capacitors and inductors are explicitly modeled within the System Model(s).
    - All LTC transformer taps are locked except those in Duke Energy Florida's area and those that were selected to allow automatic control to simulate t = 0+ conditions.
    - Modeling of events included the response of existing and planned controlled devices as reported by the owner of the device. Within the FRCC Region, there are no control devices such as static VAR controllers (SVC), high voltage direct current systems (HVDC), and Flexible AC Transmission Systems (FACTS).

A.2 – Methodology

The FRCC system models are the basis for the steady-state Long Range Reliability Study of the FRCC Region. Prior to performing the analysis, certain minor thermal and voltage concerns existing in the pre-contingency cases are addressed by the affected utilities. Addressing the Category P0 exceptions includes the modeling of planned facilities identified as necessary in previous annual assessments as well as facilities planned to mitigate a thermal limit or voltage screening exception from this study's base cases.

See *TPL-001-Contingency Selection Rationale for Long Range Transmission Study* (FRCC-MS-PL-319) found in Exhibit 3.

Appendix B – Rate C Screening Procedure

Note: Exceeding Rate C does not imply that an entity must provide a pre-contingency remedial action. Rate C's are proxy ratings that are calculated based on a variety of conditions (e.g., pre-load, time, etc.), therefore a higher rating may be available for a facility for a specified time limit allowing post-contingency mitigation.

Step 1: Run all cases against Rate C for contingencies (P1, P2, P4, P7) and allow entities to "clean up" any rating errors within the case.

a. Supply a pre-contingency switching IDEV that can be applied to the case.

b. Supply a re-dispatch IDEV that can be applied to the case.

c. Document that there is a Rate C System Operating Limit (SOL) for the facility that is greater than the value shown in the case and supply an IDEV to apply to case.

d. Document that there is a protective system or Special Protection Scheme (SPS) that would prevent the facility from exceeding the SOL.

Step 2: Re-run cases with all supplied corrections against Rate C for contingencies (P1, P2, P4, P7). Repeat step 2 until no additional corrections are required.

Step 3: Determine if facilities exceeding Rate C are candidates for pre-contingency remedial action based on impact to BES using the following criteria:

For BES Rate C Potential Violations

Option 1: Adjust facility rating to allow for post-contingency mitigation and supply the rating.

Option 2: If the rating is correct and the contingency overload does not allow for post-contingency mitigation, then supply an appropriate pre-contingency mitigation plan or IDEV.

For 69kV Rate C Potential Violations

Screen for BES impact by modeling the contingency as well as all of the 69kV facilities associated with that contingency that exceed Rate C as out of service. Evaluate the results as described in the following categories (CAT).

CAT 1: Non-Convergent Case - Determine if the problem is a voltage collapse due to excess load on a radial. Review the breaker diagram to determine if a breaker to breaker operation (typically sheds load) will yield a solution.

CAT 2: No Overloads on BES and No Rate C Overloads on 69kV facilities - Document as no impact on the BES and no further action is required.

CAT 3: Rate A BES Overload appears – The original 69kV overloaded facility should be re-evaluated to determine if the facility rating can be adjusted to allow for post-contingency mitigation to avoid BES overload. If it is determined that pre-contingency action needs to be taken, then submit an IDEV to implement that action. The contingency will be evaluated as a BES contingency requiring a pre-contingency resolution.

CAT 4: No BES Overloads, but new 69kV Rate C Overloads appear – Outage the highest 69kV Rate C overload and evaluate the results using the above categories.

Appendix C - NERC Multiple Contingency Event

Study Guidelines for FRCC Bulk Electric System

The FRCC conducts power flow and dynamic simulation studies to test those multiple contingencies that would produce the most severe grid response. These studies are performed by the Transmission Technical Subcommittee (TTS), which focus on power flow analysis, and by the Stability Analysis Subcommittee (SAS), which focuses on simulation studies and transmission grid stability. The rationale for the contingencies periodically studied by the TTS and SAS is explained in this document.

Single contingency Simulation Guides

P1-1: 3 phase fault on a generator with normal clearing
P1-2: 3 phase fault on a transmission circuit with normal clearing
P1-3: 3 phase fault on a transformer with normal clearing
P1-4: 3 phase fault on a shunt device

For the Category P1 normal clearing fault events, the normal study practice is to simulate the loss of the element without a fault since dynamic simulations of Category P5 faults with delayed-clearing (P5-1 – P5-5) typically produce a more severe impact than the Category P1 fault events. Category P1-5 (Single Pole of a DC line) is not presently applicable to the FRCC Region due to the absence of HVDC Facilities.

Multiple contingency Simulation Guides

P2-1: Opening of a line section without a fault
P2-2: SLG fault on a bus section
P2-3: SLG fault on an internal breaker (non-bus-tie breaker)
P2-4: SLG fault on an internal breaker (bus-tie breaker)
P4: SLG fault with the loss of multiple elements caused by a stuck breaker
P5: SLG fault with delayed fault clearing due to the failure of non-redundant relay
P6: 3 Phase fault (line, generator, transformer) followed by a system adjustment with another facility outaged
P7: Double circuit tower outage

Category P3-5 is not presently applicable to the FRCC Region due to the absence of HVDC Facilities.

Category P2-2, P2-3, P2-4 P6, and P7 contingencies are normally screened with power flow methods by the TTS as their potential adverse effect can be studied under steady state post fault conditions. Dynamic simulation studies are conducted for those Category P2-3, P2-4 P6, and P7 contingencies for which the steady-state results indicate a severe response (i.e., transmission voltages lower than .90 per unit or overloads greater than 100% of Rate C).

Multiple contingencies are addressed in the FRCC Stability Study performed by the SAS. This study tested those contingency events that have the most severe impact on the BES for the planning horizon. No multiple contingency performance violations were identified. The mitigation measures for the protection failure events involve protection system upgrades that can be accomplished with short lead times, consequently it is not necessary to test their performance in the longer-term planning horizon.

Appendix D - NERC Reliability Standard TPL-001-4 Table 1 Reference

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Appendix E - List of Pre-Contingency Switching

Pages contain CEII information and are not included

Appendix F - List of Participants[*]

The following entities registered with NERC as a Planning Authority and/or Transmission Planner participated in this transmission assessment either directly or indirectly:

Florida Reliability Coordinating Council, Inc.
Duke Energy Florida, LLC
Florida Municipal Power Agency[†]
Florida Power & Light Co.[‡]
Gainesville Regional Utilities
Gulf Power Company
Homestead, City of
JEA
Lakeland Electric
Orlando Utilities Commission
Seminole Electric Cooperative, Inc.
Tallahassee, City of
Tampa Electric Company

[*] Reedy Creek Improvement District coordinated with FRCC Staff.
[†] Florida Municipal Power Agency represented Beaches Energy Services of Jacksonville Beach, City of Clewiston, Fort Pierce Utility Authority, City of Green Cove Springs, Keys Energy Services, Kissimmee Utility Authority, Ocala Utility Services, and City of Lake Worth Beach.
[‡] Florida Power & Light Company represented Florida Keys Electric Cooperative Association (FKEC), Utilities Commission of New Smyrna Beach (NSB), Florida Public Utilities Company (FPUC), Gulf Power Company (GULF), and Lee County Electric Cooperative, Inc (LCEC).

Exhibits 1-3

Pages contain CEII information and are not included

FLORIDA TRANSFER CAPABILITY ASSESSMENT:

Projections for 2023 Summer, 2023/24 Winter Assessment

*Final Report**
April 2022

*(*CEII Information Removed)*

TRANSFER CAPABILITY ASSESSMENT:

FLORIDA / SOUTHERN INTERFACE

Projections for 2023 Summer
and 2023/24 Winter Assessment

Final Report
April 2022

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APPENDICES

SUMMARY

The projected transfer capabilities between (1) the FRCC Region (peninsular Florida) and the Southern Balancing Authority within the Southeastern subregion of the SERC region (Southern) and (2) the Southern Balancing Authority and Gulf Power have been assessed by the Florida owners of the Florida/Southern transmission interface and are documented in this report. The Near-Term Transmission Planning Horizon values shown in Table 1 are provided for informational purposes. A more detailed summary of assessment results is provided in Appendix A. These assessment values were determined in accordance with the interface methodologies and criteria of the importing utilities for determining interface transfer capabilities. These assessment values can be utilized for screening purposes to identify potential future transmission system limiting facilities that could impact the Bulk Electric System's ability to reliably transfer energy in the Near-Term Transmission Planning Horizon. A detailed analysis using the current models and specific assumptions would need to be performed to identify applicable constraints and solutions needed to define the Total Transfer Capability (TTC). More specifically, transfer capabilities for the Florida/Southern and Southern/Gulf Power transmission interfaces are dependent upon the specific source and sink combinations that comprise the total transfers and as such, may require a specific study.

The summer case is representative of the June through September time period and the winter case is representative of the December through February time period for the year/season specified. The transfer capability values are similar to the values identified in previous assessments.

Table 1

Season	Fla[1] to SOU	SOU to Fla[1]	Gulf to SOU[2]	SOU to Gulf[2]
2023 Summer	2100	3100	300	1700
2023/24 Winter	0	3800	1000	1400

1. "FLA" refers to "peninsular Florida". ie. simulations where the source/sink is "FPL, TAL, DEF, and JEA".
2. The table above shows the incremental transfer capability (ITC) for Gulf/SOU transfer.

INTRODUCTION

The primary purpose of this analysis effort is to perform an assessment of the Florida/Southern and Southern/Gulf transmission interfaces for the Near-Term Transmission Planning Horizon and to identify potential future transmission system limiting facilities that could impact the Bulk Electric System's ability to reliably transfer energy across these interfaces. Power imports to Florida were evaluated based on the methodologies and criteria of the Florida owners of the transmission interface. Power exports from Florida to the Southern Balancing Authority (SBA) were evaluated consistent with the methodologies and criteria of the SBA. Power imports to and exports from Gulf Power were also evaluated.

The models created for the Florida assessment of the Florida/Southern and Southern/Gulf transmission interfaces were coordinated with the SBA interface owners. The Southern models were based on the latest available series of the 2021 SBA base cases. The FRCC models were based on the 2021 FRCC databank.

Contingency simulations of the Florida, Southern and Gulf Power systems were performed using criteria and methodology consistent with NERC guidelines/standards and those reported to FERC in the FERC 715 filings. All single branch (including auto transformers) and generating unit contingencies within the FRCC, Southern and Gulf Power Companies were considered for determining thermal limitations. For the voltage stability analysis, selected single and double contingencies were considered. Additionally, a list of plant outages and double contingencies relevant to the Florida/Southern Transmission Interface was developed in coordination with both the Florida and SBA owners of the interface and is provided in Table 2.

The methodology used for the determination of Southern to Florida transfer capability assumes all facilities are available. The interchange assumptions for the transfer capability test cases start with firm interchange commitments. The table below shows the firm transfers that were used in this analysis.

Season	SOU-FRCC Firm Transfer	SOU-Gulf Firm Transfer
S23	231	869*
W23	331	875*

*Value includes PS NITS for load on GULF

Additional transfers to the FRCC balancing areas with an allocated or assigned right to interface capability are then modeled to increase transfers across the Southern/Florida and

Southern/Gulf transmission interfaces. For the voltage stability analysis, selected single and double contingencies were tested using a Power/Voltage ("P/V") sensitivity method. Voltage Security Factors ("VSF") are applied to the P/V results to determine a transfer capability with an adequate margin of voltage security. Consistent with industry practice, a VSF of 5.0% is used for single contingencies and a VSF of 2.5% is used for double contingencies. In this assessment the PV analysis was performed using Power Grid Engineering & Markets' (Power Gem) Transmission Adequacy & Reliability Assessment (TARA) software, which provides more consistent results as the impact of incremental transfers is studied. Note that in TARA, both the no-solve point and the point at which minimum voltage limits are reached are monitored.
The methodology used for determination of Florida to Southern transfer capability assumes conditions with all generating units available.

Both Southern to Florida and Florida to Southern transfer capability studies were performed scaling generation for the sending system and scaling load for the receiving system to accomplish more conservative transfer limit levels. In the case of Gulf Power, the studies were performed scaling generation for both conditions, when Gulf Power was the sending and the receiving system.

With power transfers at or close to the transfer capability level, there are some contingencies that cause overloads. Overloaded facilities that do not respond to transfers (facilities with outage transfer distribution factors[1] lower than 3%) were not considered limitations to transfers.

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[1]Transfer Distribution Factor (Dfax) - The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

ASSESSMENT of FLORIDA TO SOUTHERN TRANSFERS

Contains CEII information and is not included

ASSESSMENT of GULF POWER TO SOUTHERN TRANSFERS

Contains CEII information and is not included

Table 2 – Contingency List

Contains CEII information and is not included

Appendix A
Assessment of Transfer Capabilities For
Near Term Planning Horizon

Contains CEII information and is not included