State of Florida

Public Service Commission

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-M-E-M-O-R-A-N-D-U-M-

DATE: March 22, 2016

TO: Carlotta S. Stauffer, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Public Utilities Supervisor, Division of Engineering POE
Moniaishi Mtenga, Engineering Specialist, Division of Engineering MMM

RE: FRCC 2015 Studies and Reports for the 2015 TYSP Workshop

Attached is the Florida Reliability Coordinating Council's 2015 Studies and Reports for the 2015 Ten-Year Site Plan Workshop. Please place this item in Docket No. 150000 – Undocketed Filings for 2015, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact Phillip Ellis at pellis@psc.state.fl.us or 850-413-6626.

Attachment

FRCC
Florida Reliability Coordinating Council, Inc.

2015
Ten-Year Site Plan Workshop
FRCC Studies and Reports

September 15, 2015

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A

FRCC
2015 Load & Resource Reliability Assessment Report

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1.0 Purpose

A key responsibility of the Florida Reliability Coordinating Council (FRCC) is to annually assess the reliability of the Bulk Power System in the Region, and to ensure resource adequacy as required by the Florida Public Service Commission (FPSC) as well as a requirement for compliance with FRCC Standards and North American Electric Reliability Corporation (NERC) Reliability Standards. NERC is the Electric Reliability Organization (ERO) of the United States.

As part of this annual assessment, the FRCC aggregates and reviews forecasted load and resource data reflecting expected conditions 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, 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 peninsular Florida east of the Apalachicola River by analyzing projections of Reserve Margins, Loss of Load Probability (LOLP), Availability Factors (AF), and Forced Outage Rates (FOR). In addition, this report incorporates various reliability-based aspects of work performed by the Load Forecast Working Group (LFWG), Transmission Working Group (TWG), Fuel Reliability Working Group (FRWG), and examines renewable energy use in Florida.

2.0 Terms and Definitions

2.1 Terms are defined within the document.

3.0 Responsibilities

3.1 Resource Working Group (RWG)

The RWG is responsible for reviewing document.

3.2 Load Forecast Working Group (LFWG)

The LFWG is responsible for reviewing document.

3.3 Fuel Reliability Working Group (FRWG)

The FRWG is responsible for reviewing document.

3.4 Transmission Working Group (TWG)

The TWG is responsible for reviewing document.

3.5 Planning Committee (PC)

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

4.0 Executive Summary

In summary, the findings of the 2015 Reliability Assessment Report of the FRCC Region are:

- Peninsular Florida's electric service is projected to be reliable from a resource adequacy perspective throughout the ten year planning horizon.
    - Reserve margins for the FRCC Region for the summer and winter peak hours are projected to exceed 20% for each year in the ten-year period, well above the FRCC's minimum Reserve Margin Planning Criterion of 15%.
    - Projected high Reserve Margins, projections of low Loss of Load Probability (LOLP) values, supplemented with projected low Forced Outage Rates (FOR) and high Availability Factors (AF) for most of the ten-year period, result in a projection that the peninsular Florida system is expected to be reliable during the ten-year reporting period.
    - Due to the degree to which the peninsular Florida system is becoming increasingly dependent upon Demand Side Management (DSM) to meet its Reserve Margin criterion, the FRCC and certain utilities are also examining system reliability utilizing a generation-only Reserve Margin perspective.
- The load forecast is both reasonable and sound while reflecting moderate growth over ten years, but a lower load growth than in prior years.
    - The expected average annual growth rate for Net Energy for Load (NEL) is approximately 1.1% per year compared to 1.3% in the previous forecast.
    - Firm summer peak demand is expected to grow by 1.5% per year compared to 1.7% in the previous forecast.
    - Firm winter peak demand is expected to grow by 0.9% per year compared to 1.4% in the previous forecast.
- A net total (including unit retirements) of more than 7,000 MW of additional utility-owned generation resources are planned for the FRCC Region.
    - More than 10,600 MW of new firm generation are planned for the FRCC Region with 7,200 MW being combined cycle capacity, 3,300 MW being combustion turbine capacity, 100 MW in firm solar capacity (and approximately 600 MW of additional non-firm solar), and almost 600 MW in unit uprates.
    - Approximately 4,000 MW of plant retirements are expected from coal plant capacity and older, less efficient steam and combustion turbine capacity.
- Natural Gas is expected to remain the primary fuel source for the region and the majority of proposed new generators within the FRCC Region are expected to use natural gas as their primary fuel.
    - Natural gas is projected to provide approximately on average 62.1% of the electrical energy (GWh) in peninsular Florida in the coming ten years.

- The existing pipeline capacity within the Region supports the current generating capacity needs of the Region.

- 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. It should be noted that additional coordination may be required in the event of a long-term failure of key elements of natural gas delivery infrastructure.

- Significant proposed gas pipeline projects (Sabal Trail and Florida Southeast Connection) is expected to provide 0.83 Bcf of incremental gas supply to peninsular Florida in May 2017 and increasing to 1.1 Bcf by 2021. Completion of these projects will enhance fuel transportation reliability by increasing supply and delivery diversity for the FRCC Region.

5.0 FRCC Reserve Margin Review

The FRCC has a reliability criterion of a 15% minimum Regional 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 Regional 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[1]. Other utilities employ a 15% to 18% minimum Total Reserve Margin planning criterion.

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

[1] 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.psc.state.fl.us/library/Orders/99/15628-99.pdf)

Figure 1 below shows that the projected summer Total Reserve Margins from the *2015 Regional Load & Resource Plan*[2] continue to be above the FRCC's minimum 15% Total Reserve Margin requirement. In fact, the 2015 projected summer Total Reserve Margins exceed 20% for every year in the ten-year forecast period. *(Note that information contained in this Figure, and in subsequent Figures and Tables, is consistent with information presented in the individual utilities 2015 Site Plans. These Site Plans present information from the utilities' 2014 and early 2015 resource planning work.)*

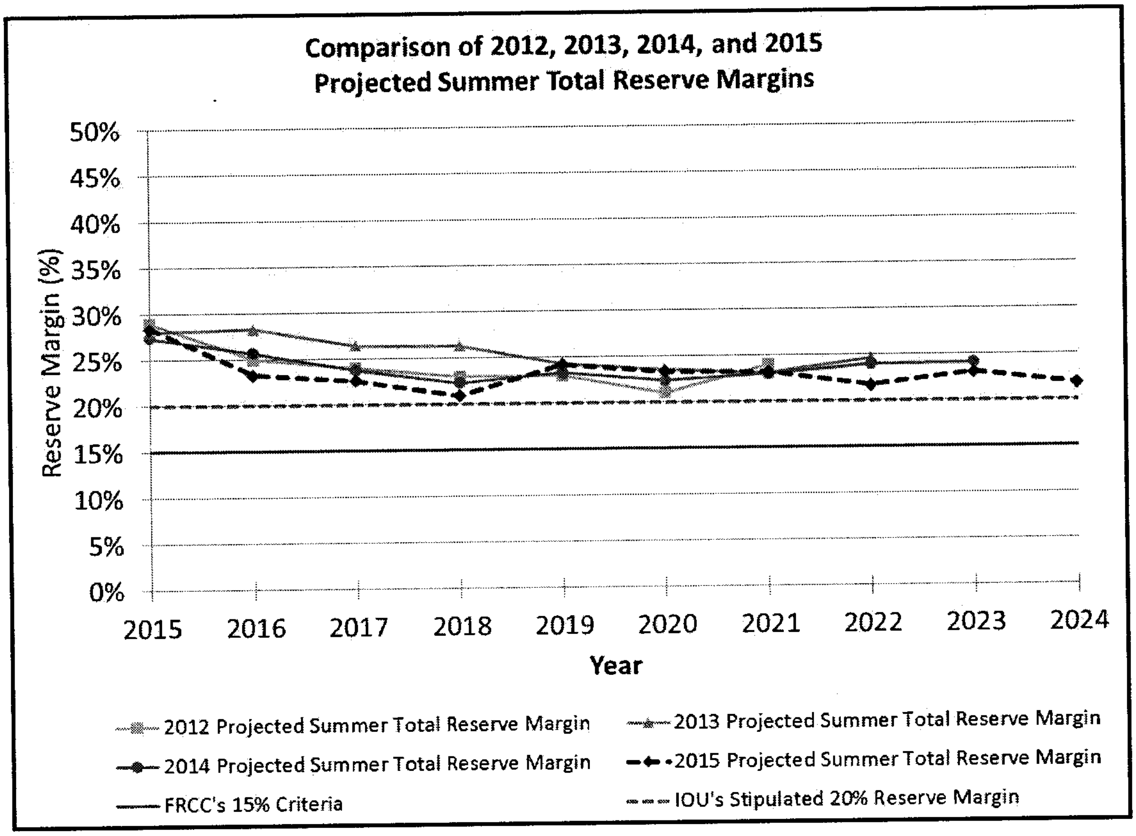

Figure 1
Trends in Projected Summer Total Reserve Margins

[2]2015 Regional Load & Resource Plan (https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202015%20Load%20and%20Resource%20Plan.pdf)

In a similar manner, ***Figure 2*** below shows the projected winter Total Reserve Margins from the *2015 Regional Load & Resource Plan.* The 2015 projected winter Total Reserve Margins are also over 20% for every year in the ten-year forecast period. Primary drivers of the higher winter reserve margins are: (i) colder ambient air temperatures in the winter compared to the summer result in more capacity (MW) output from many generators in winter compared to summer, and (ii) the forecast of winter peak demand is lower in the current forecast compared to the prior forecast.

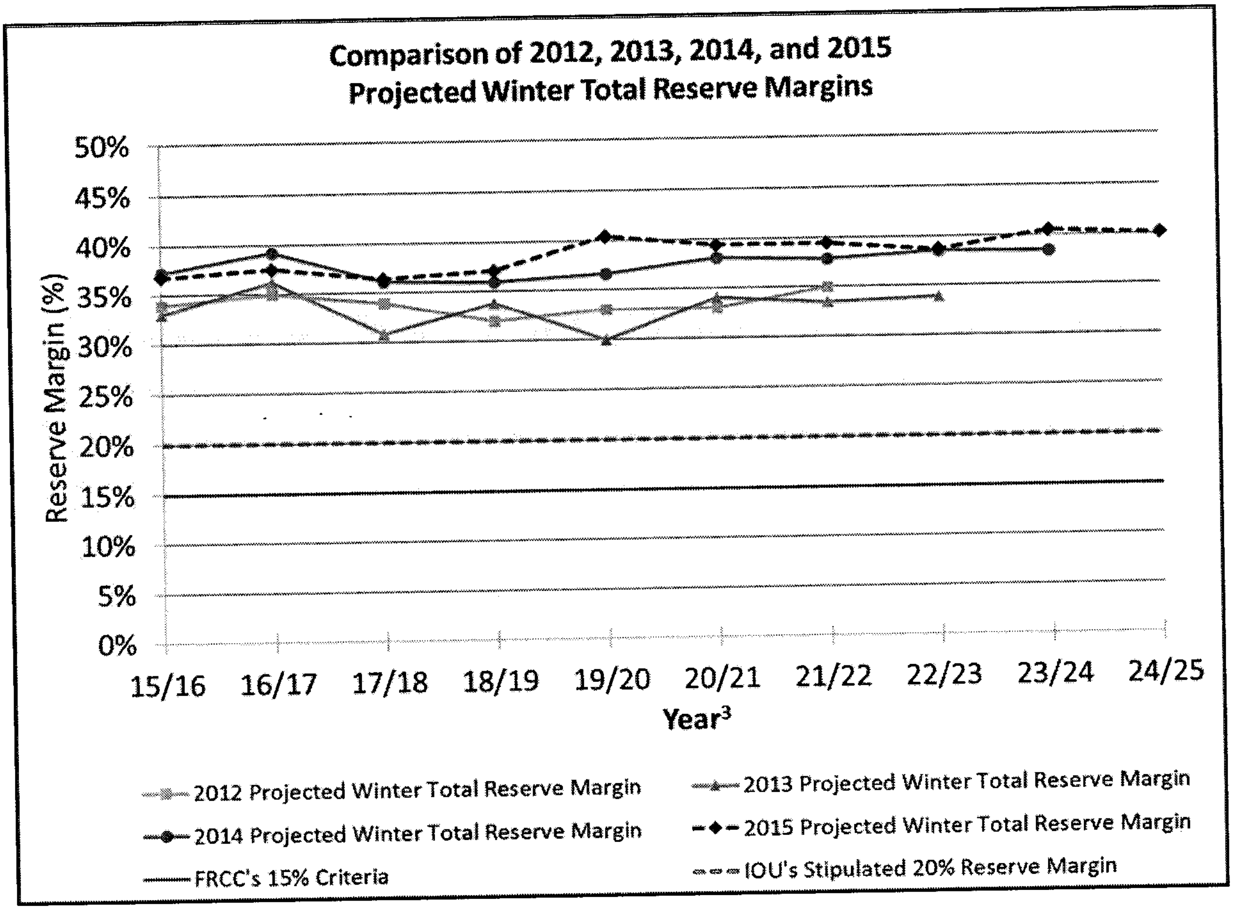

Figure 2
Trends in Projected Winter Total Reserve Margins

[3] The winter season spans from the 4th quarter of one year through the 1st quarter of the next. For example, the year 15/16 refers to the winter season spanning from the 4th quarter of 2015 through the 1st quarter of 2016.

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 Rates (FOR) and Availability Factors (AF) are developed in 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, FPSC, and NERC requirements. Further, other considerations that can affect system reliability are also considered and evaluated.

LOLP Analysis

The FRCC has historically used an LOLP analysis to establish the adequacy of reserve levels for peninsular Florida. The LOLP analysis uses projected system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to meet forecasted loads. The purpose is to verify that the projected LOLP for the system does not exceed the criterion of a maximum LOLP of 0.1 day in a given year. In addition to maintaining this LOLP resource 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.

Until recently, the Resource Working Group (RWG) performed periodic LOLP studies every 3 to 5 years. However, NERC's Probabilistic Assessment requires analyses of Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) every two years. Therefore, the RWG is now conducting LOLP analyses every two years, in parallel with the EUE and LOLH analyses. All three analyses utilize the same data.

The most recent LOLP analysis was conducted in 2014. At that time, "base" LOLP projections were obtained for peninsular Florida for the years 2014 through 2018 using updated assumptions and forecasts that correspond with the Florida utilities' 2014 Ten Year Site Plans (TYSP). Beyond the base or "reference" case values for LOLP, projected LOLP values for a variety of extreme 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.

The 2014 LOLP analysis indicated that, with all transmission facilities in service, the reference case for the peninsular Florida electric system is not projected to exceed the planning LOLP criterion of a maximum of 0.1 days per year through 2018 as shown in ***Table 1*** below except in 2018 in the extreme scenario cases which assume that either the capabilities of DSM DR programs are unavailable (in which cases the LOLP criterion is exceeded in 2017 and 2018) or a high load situation (occurs (in which case the LOLP criterion is exceeded in 2018). The FRCC considers both of these extreme scenario cases as unlikely.

The FRCC has also determined, through evaluation of system FOR and AF projections in 2014, and again in 2015 (as discussed below), that these most recent LOLP projections will likely also be representative of projected LOLP values for peninsular Florida throughout the next ten years, (i.e., the peninsular Florida system is projected to be reliable from an LOLP perspective). Based on these analyses, the RWG recommends that the current 15% Total Reserve Margin Planning Criteria be maintained.

	Base Case	No Availability of Firm Imports	No Availability of Demand Response	High Case
Year	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)	LOLP (Days/Year)
2014	0.000000	0.000000	0.000005	0.000000
2015	0.000002	0.000043	0.008358	0.000063
2016	0.000000	0.000001	0.002121	0.000215
2017	0.000045	0.000120	0.058800	0.003293
2018	0.000129	0.000438	0.170077	0.018954

Table 1
2014 LOLP Results[4]

The FRCC is scheduled to conduct an updated LOLP analysis in 2016 at the same time that new EUE and LOLH analyses are conducted.

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

Generating unit reliability is a primary driver of LOLP results. For a number of years, the RWG has tracked and monitored capacity (MW)-weighted Forced Outage Rate (FOR) and Availability Factor (AF) measures for individual utility systems and the FRCC Region as a whole. This assessment was again conducted as part of the 2015 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 historic values. Projections of these annual measures for individual utilities and the region as a whole, 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 as presented in each utility's 2015 Site Plan. These 2015 projections for FOR and AF values were compared to the values projected in 2012, 2013, and 2014.

[4] The 2014 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.

As seen in ***Figure 3*** below, the 2015 projection of FOR values remain generally in-line with projected values from the last several years. The 2012 projected FOR values showed an increase in the first year due to an assumed extended outage of Crystal River Unit 3. However, the current projected values account for the fact that this unit has now been retired. Therefore, the more recent projections no longer show the same increase in projected FOR for the year 2015. The current projected FOR values are relatively flat and in a relatively narrow range. This trend is consistent with projections from the prior years. The projected flat FOR values are also consistent with the projected low LOLP base case values from the 2014 LOLP analyses presented earlier in ***Table 1***. This consistency in FOR projections further indicates that the peninsular Florida system is projected to remain resource adequate and maintain its reliability from 2015 through 2024.

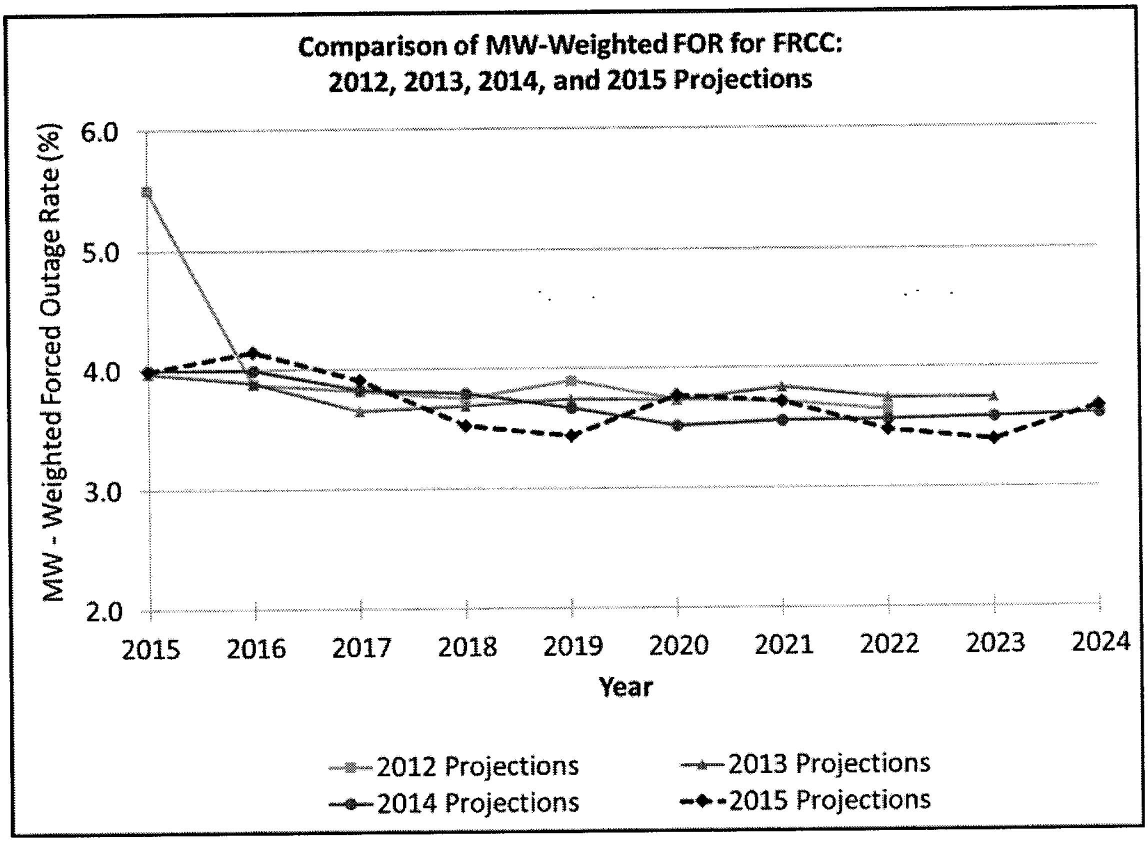

Figure 3
Trends in Projected Forced Outage Rates (FOR)

Though unit AF is not an input to LOLP calculations, it is often used as an indicator that generally correlates well with reliability data. ***Figure 4*** below shows that 2015 projections of MW-weighted AF throughout the ten-year period are in line with AF projections from recent years. The projections from resource planning work conducted in these four years remain consistent in a narrow range from approximately 88% to 90% with a general trend of increasing AF values.

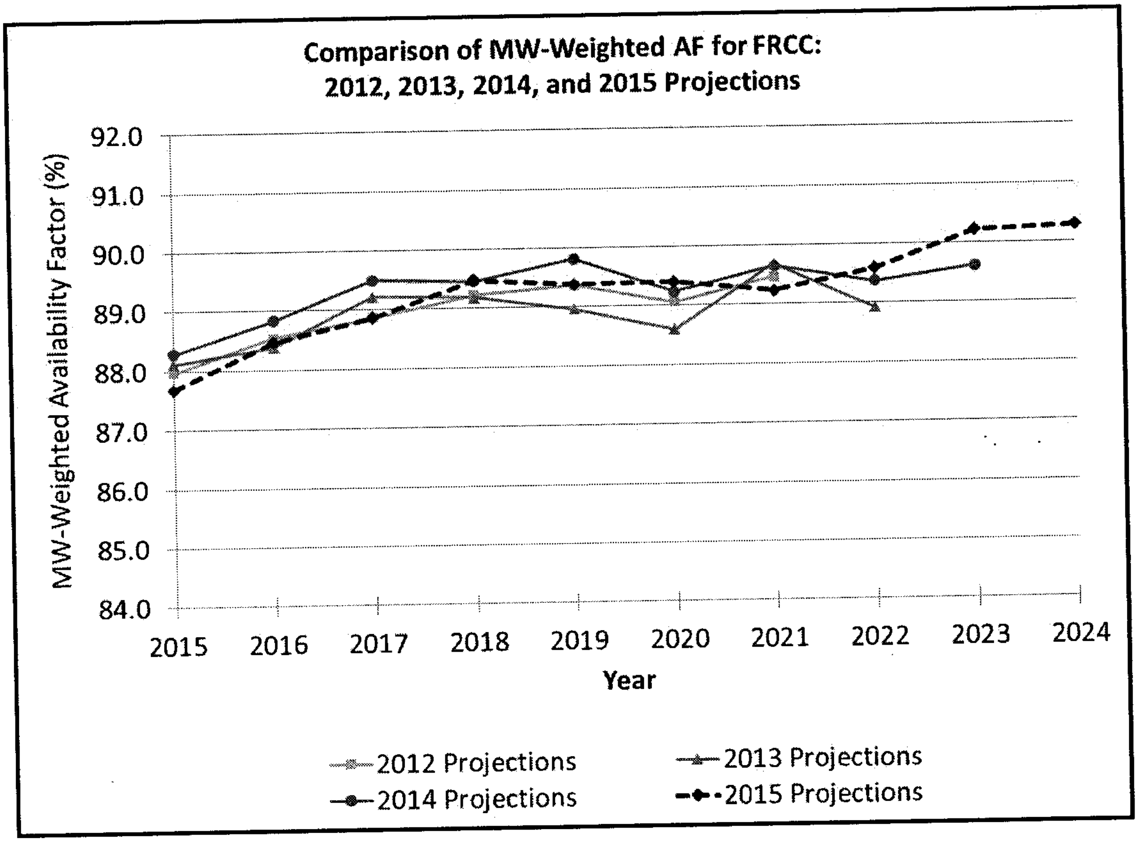

Figure 4
Trends in Projected Availability Factors (AF)

The results of the AF analyses, combined with the results of the FOR analyses depicted in ***Figure 3,*** the very low projected LOLP base case results for 2014 – 2018, 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 2015 Load & Resource Plan document and presented in the previous section in ***Figure 1*** and ***Figure 2***), support a conclusion that the peninsular Florida system is projected to continue to be reliable throughout the ten-year period addressed in this document.

Resource Adequacy Review Process

In addition to the NERC Probabilistic Assessment work, other resource adequacy work that is conducted can be summarized as follows:

Review of statistics currently used for tracking system performance

As previously discussed, the RWG performs LOLP studies every other year and annually reviews projected system-wide MW-weighted FOR and AF as indicators of resource adequacy. The LOLP studies are performed every other year in parallel with the NERC Probabilistic Assessment. The indices of projected MW-weighted FOR and AF are effective in indicating whether the projected reliability of the peninsular Florida system is changing, both in magnitude and direction, over time from an LOLP perspective.

Examination of potential new statistics for evaluating system reliability

In 2012, the RWG also began to examine an additional aspect of the peninsular system that could have implications for the reliability of the system. This aspect is 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. In 2014, 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 is now in use in all of FPL's IRP analyses and FPL's objective is to achieve a minimum 10% GRM in practice beginning in the year 2019. 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 TEC's supply-side reserve margin reliability criterion that TEC has used in its IRP process for approximately a decade. Both of these criteria are essentially designed to ensure that there is an adequate generation component as the utilities meet their 20% total reserve margin criterion.

In order to examine the extent to which the peninsular Florida 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[5] values was first developed based on information presented in the utilities' 2012 Site Plans and the projected generation-only Reserve Margin for peninsular Florida has been analyzed by the RWG in each subsequent year. The generation-only Reserve Margin analysis for peninsular Florida was conducted again this year by aggregating the utilities' 2015 Ten Year Site Plan projections in which incremental and cumulative load management, and incremental utility program energy conservation/energy efficiency and other demand reduction contributions, are excluded. The resulting generation-only Reserve Margin projection, presented in ***Figure 5*** below, shows peninsular Florida's projected future Reserve Margins when considering only generating unit contributions.

[5] 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.

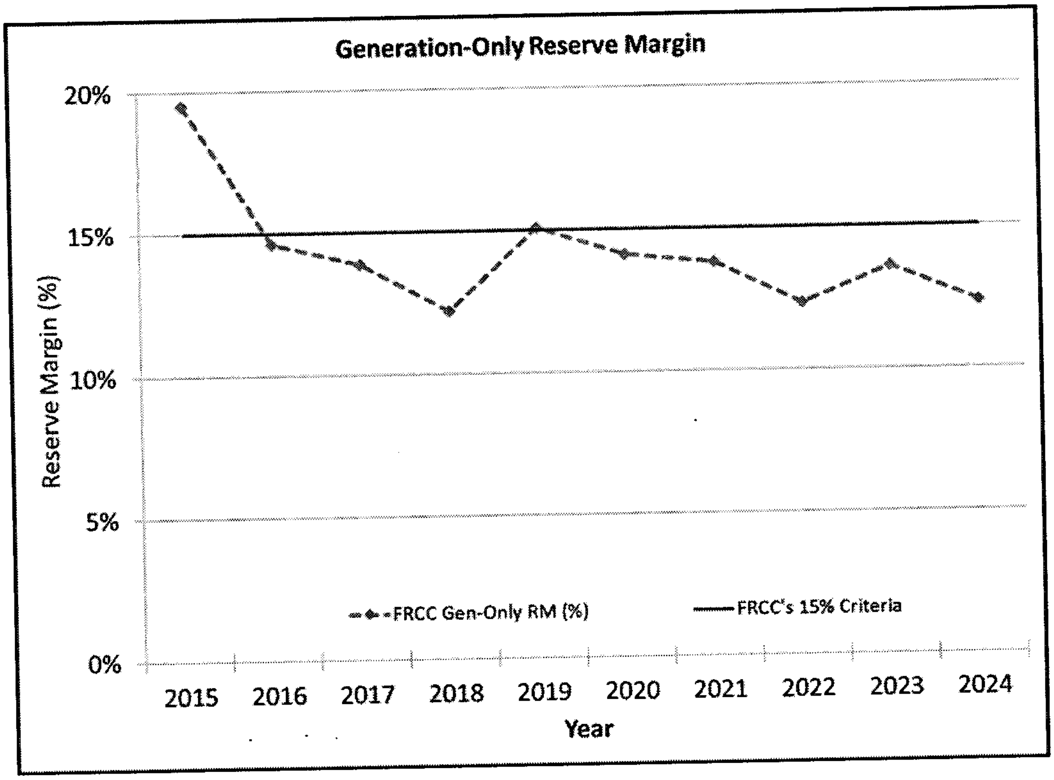

Figure 5
Projected Generation-Only Reserve Margin

As shown in ***Figure 5***, the generation-only Reserve Margin values for peninsular Florida are projected to decrease through 2018, but then to remain relatively steady within a range of approximately 12% to 15% for the remaining years of the projection. This indicates that the projected trend of steadily increasing dependence on DSM for maintaining reliability of the peninsular Florida system that was projected in each of the last several years, is now anticipated to stop beginning in 2019. At that time, the GRM for peninsular Florida is projected to hold steady going forward (but at lower levels than in 2015). The primary reasons for this change in the projection of dependence on DSM for system reliability of peninsular Florida are: (i) DSM's diminished cost-effectiveness in Florida was appropriately reflected in lower DSM Goals for Florida utilities for the 2015 – 2024 time period, and (ii) FPL's use of its 10% minimum GRM reliability criterion (recognizing that the FPL system constitutes approximately 50% of the peninsula's projected capacity and load.)

The FRCC and individual utilities including FPL will continue to evaluate these generation-only Reserve Margin projections and their potential implications for system reliability.

<u>Fuel Deliverability</u>

The dependency on natural gas and the possibility of natural gas supply or delivery disruptions and potential impacts on the long term adequacy of FRCC resources to meet customer load has been considered in resource adequacy reviews. The FRCC has undertaken initiatives to increase coordination among natural gas pipeline operators and generators within the Region. 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.

Results of the most recent analysis indicate that risk to the reliability of the power system within the FRCC Region related to projected shorter term gas delivery disruptions can be mitigated through use of dual fuel units and increased fuel management coordination.

Peninsular Florida has become dependent on natural gas as a source of fuel for electric generation. This is expected to continue over the coming years as utilities continue to install new natural gas-fired generation to meet new load, as well as replace existing generating facilities with more efficient natural gas-fired generation. Approximately 58.5% of the energy delivered in Florida in 2014 was generated by natural gas. Natural gas is expected to continue to be peninsular Florida's primary fuel generating approximately 62.1% of the electric energy consumed on average through the year 2024. However, the state has no native gas production and currently relies primarily on two existing interstate natural gas pipelines with limited interconnections between them, (Gulfstream Natural Gas System (Gulfstream) and Florida Gas Transmission Company (FGT)) for more than 90% of the supply transported into the Region. These two pipelines currently have the ability to deliver almost 4.4 billion cubic feet per day (Bcf/day). FGT's delivery capability is approximately 3.1 Bcf/day and Gulfstream's delivery capability is approximately 1.3 Bcf/day. More than 80% of the natural gas supply from these two pipelines is dedicated to serving electric generation needs in Florida.

In addition to the two main pipelines delivering into the state, gas is also transported into peninsular Florida via Southern Natural's Cypress Pipeline system (Cypress). This pipeline is capable of delivering about 400 million cubic feet per day (MMcf/day) into Florida. At this time, only about 60 MMcf/day of delivery capacity on Cypress is contracted for delivery to a direct use market in Florida. The vast majority of the gas from Cypress is delivered to FGT and is contracted to flow through FGT to reach end use markets. Consequently, the majority of this capacity is not additive to the FGT delivery capacity.

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.

In regard to future requirements, these existing natural gas pipelines into Florida are almost fully subscribed. However, Florida's natural gas needs are expected to increase in the coming years. To meet the high demand, the gas transportation infrastructure serving the state is expected to increase by 2017. Given that the state relies on primarily two pipeline service providers that source natural gas supplies from primarily Gulf Coast area supply sources and infrastructure, Florida will benefit from projects that increase supply flexibility, delivery diversity, and increased interconnections which includes the proposed Sabal Trail, Sabal Trail Central Florida Hub, and the Florida Southeast Connection pipeline projects that are currently moving through the Federal Energy Regulatory Commission (FERC) Certificate process. These projects will provide access to a new supply source from Transco's Zone 4 Pool at its compressor station 85 into the FRCC Region.

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. Therefore increasing pipeline diversity ultimately will decrease vulnerability to unplanned outages of any gas delivery infrastructure.

Transmission Capability

The RWG considers available transmission information, including deliverability of generating resources, in the annual Reliability Assessment to determine if additional studies need to be performed to evaluate the impact of transmission constraints on generation.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 through TPL-004. These studies include: long range studies, seasonal assessments, sensitivity studies, integration studies, and interregional assessments. The results of the short-term study for normal, single, and multiple contingency analysis shows that all potential thermal and voltage constraints occurring within the FRCC Region can be managed successfully by operator intervention. The longer-term study is performed to identify potential issues and to consider multiple alternatives. No major projects requiring long lead time have been identified.

Environmental Compliance

At this time, the RWG 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 resource adequacy process through the individual utility resource planning processes. Several federal environmental rules were recently enacted, including MATS (Mercury and Air Toxics Standards), CSAPR (Cross-State Air Pollution Rule), CWIS (Cooling Water Intake Structures), CCR (Coal Combustion Residuals), and NESHAP/RICE (National Emission Standards for Hazardous Air Pollutants / Reciprocating Internal Combustion Engine). Specifically, the MATS rule is one of the factors that led to the retirement of several units as well as the installation of additional equipment at other existing units. The NESHAP/RICE rule will affect the usage of backup generators. Many customers who participate in utility commercial/industrial load control programs utilize such equipment. As a result of this rule, costs for these participating customers may increase and/or utilities may have to impose operational limits on the dispatch of their load management resources. These changes have the potential to decrease the MW available under the utilities' commercial/industrial load management programs and/or to decrease the effectiveness of this DSM resource. Any other utility-specific, or generator-specific, emission limitations and/or environmental compliance costs are presently captured by incorporating these in the production costing models used in the individual utilities' resource planning processes.

There continues to be considerable discussion at the Federal level regarding renewable energy. Future federal requirements may have an impact on the type of generating resources that may be needed to meet potential new renewable energy mandates. Many of the potential mandates that have been considered to-date address energy (GWh) output and seek to require that a certain percentage of annual energy output be met by renewable or "clean" (i.e., produce no air emissions during operation) generating sources only. Renewable energy sources deployed or deployable in Florida can address an energy-only mandate. With the exception of biomass and, to a lesser degree, photovoltaics (which is currently projected to provide some percentage of its nameplate rating as firm summer-only capacity), renewables may not significantly contribute to providing firm capacity that will be needed to meet the Region's growing load and to maintain system reliability. It is noteworthy that additional nuclear capacity, such as that projected by FPL beginning in 2027/2028, would provide clean energy while also fully providing firm capacity.

On June 2014, the U.S. EPA issued the Clean Power Plan Proposed Rule that addresses greenhouse gas emissions for all existing power plants in the U.S. The EPA requested written comments on the proposed rule and extensive comments from Florida and other states have been submitted pursuant to that request. After considering these comments, the EPA is scheduled to issue its final rule in/shortly after the summer of 2015. Because this FRCC document is primarily focused on the utilities' 2014 resource planning work that was reported in their 2015 TYSPs, the utilities' resource plans and this document could not specifically address the final rule. The utilities will take into account the final rule, once it has been issued, in their resource planning work during the remainder of 2015. Future FRCC Reliability Assessment Reports will account for any appropriate changes in peninsular Florida utilities' resource plans in response to the final rule.

Future Work on Resource Adequacy

The LOLP analyses discussed earlier utilize 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 seasonably. It must also be recognized that overall resource adequacy must also account for considerations such as transmission constraints and fuel deliverability. The RWG reviewed these considerations along with the results of both the 2014 NERC Probabilistic Assessment and the 2014 LOLP analysis, and recognized areas that can be addressed to add more depth and detail to the resource adequacy analysis.

The FRCC will continue to conduct various studies to evaluate Regional resource adequacy including the following:

LOLP Analysis

- Load Forecast Uncertainty

  The current modeling approach assumes the most likely load forecast prevails (with the exception of scenario analyses that addresses extreme summer and winter peak load). In addition, a sensitivity analysis was performed assessing a high load case for the Region to account for load forecast uncertainty. Probabilistic forecasts are being developed based on Monte Carlo type simulations of weather and Florida population growth, and will be incorporated into future studies in the analysis of forecasted load variability.

- Load Variation Model

  The current modeling approach uses an enhancement to the modeling program that incorporates a load variation feature.

- Major Maintenance Schedule Variation

  The current modeling approach uses specific planned outage schedules for near-term years as projected by member entities for their generating units.

Analysis of Growing Dependency on DSM to Maintain System Reliability

As previously discussed, the RWG now examines annually the extent to which peninsular Florida is projected to be dependent upon DSM, rather than generation, to maintain system reliability and the implications of that degree of dependence. This issue will continue to be examined by the RWG, and by individual utilities, in subsequent years.

Transmission Constraints

The current modeling approach assumes that, with all transmission facilities in service, sufficient transfer capability exists between all utility systems within the FRCC Region and SERC Reliability Corporation (SERC) with the exception of sensitivities where SERC transfer is explicitly limited or precluded. In addition, the current modeling approach assumes that each utility has the ability to import power for the loss of internal generation and that each utility has the ability to export their share of operating reserves.

7.0 FRCC Load Forecast Evaluation

The 2014 demand for electricity by peninsular Florida consumers increased 1.4%. The state's average per-customer consumption continued to decline for all classes in 2014, except for Residential class that experienced an increase of 1.4%. This increase could be the result of weather or it could be the impacts of a healthier economy. It is too soon to tell if this is a new trend or just an anomaly. Average per-customer consumption growth is projected to be at 0.4% per year until 2017 and relatively flat thereafter. Commercial and Industrial sectors continue to have a steady customer growth. However, impacts of conservation and energy efficiency, including the impacts of energy efficiency building codes and appliance standards, continue to contribute to the declines in per-customer consumption as reflected in the current forecasts of customers, demand, and energy consumption.

Energy sales are projected to grow more slowly than previously forecasted. The projected annual average growth rate for energy sales is now 1.2% compared to last year's projection of 1.4%. Customer growth is projected to accelerate over the forecast horizon; however, it is not projected to return to pre-recession levels. The projected average annual growth rate for customers is 1.4% compared to pre-recession growth rates of over 2.5%.

The FRCC Load Forecast was thoroughly scrutinized to account for the volatility in most macro-economic factors at the time the individual utility forecasts were developed and to assess how the member utilities are accounting for these factors in their customer, energy, and peak demand forecasts. Florida's economic outlook, historical forecast variances, and benchmarking with recent history constituted the other elements that were analyzed in this evaluation process.

The impacts on load growth from the *Energy Policy Act of 2005*[6] and the *Energy Independence and Security Act of 2007*[7] were analyzed. 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 along the logical assumption that each utility is most familiar with its own service territory and the behavior patterns of the customer base. The load forecast evaluation process undertaken by FRCC is designed to ensure that each utility is availing itself of the best available information in terms of data, to understand which forecasting models are used, and, to a certain degree, seek consistency of assumptions across all utilities. FRCC's Load Forecasting Working Group (LFWG) reviewed in detail each utility's forecast methodology, input assumptions and sources, and output of forecast results. Sanity 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 the science of forecasting and statistical modeling, there still remains an amount of risk or 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.

[6] Energy Policy Act of 2005 (http://www.epa.gov/oust/fedlaws/publ_109-058.pdf)
[7] Energy Independence and Security Act of 2007 (http://energy.senate.gov/public/_files/getdoc1.pdf)

In the short-run, weather deviations from the normal are the most important factor. However, population growth, economic performance, price of electricity, changing technology, changing consumption patterns, and efficiency 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. 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 that can be measured by the size of the weather-normalized forecast variance.

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 and technically assesses 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 ultimate measure of how well a model is performing is the size of the weather-normal forecast variance.

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. The FRCC's review ensures that all employed models portray good statistical properties with correct specifications between the key factors affecting the level of demand for electricity and the resulting load forecast. 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*[8], and with *Moody's Economy.com*[9], all reputable forecasting organizations. The price of electricity was

[8] Bureau of Economic and Business Research (http://www.bebr.ufl.edu/taxonomy/term/44?page=1)

[9] Moody's Economy.com (http://www.economy.com)

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 all historical weather 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. 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 definition of "normal" weather is then employed throughout the forecast horizon, implying that an "abnormal" weather outlook would not be an assumption and would not be a factor in projecting load. All utilities assumed a "normal" weather outlook.

The economic outlook of the local and national economy was obtained from several reputable economic forecasting firms such as *Global Insight*[10], *Woods and Poole*[11], and *Moody's Economy.com*[9]. 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.

Outputs

To assess the quality of the load forecasts, two measures were employed. The current forecast was compared to: (1) the prior forecast developed last year, and (2) the recent historical past. The 2015 Regional load forecast is lower than the 2014 forecast primarily due to more utilities capturing appliance efficiencies in their forecasting models or using more updated appliance efficiency assumptions.

The projected average annual growth rate for customers over the long-term planning horizon remains the same as the previous forecast of 1.4%. The Net Energy for Load (NEL) and summer and winter peak demands are forecasted to be lower than in the previous forecasts. The current average annual growth rate for NEL is 1.1% per year compared to 1.3% per year in the previous forecast. Firm summer peak demand is expected to grow by 1.5% per year compared to 1.7% peak demand growth rate in the previous forecast. For firm winter peak demand, the average growth rate is now expected to be 0.9% per year compared to 1.4% per year in the previous forecast.

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 out of line. While historic load

[10] Global Insight (http://www.globalinsight.com)
[11] Woods and Poole (http://www.woodsandpoole.com/)

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.

Results

The major differences between the 2015 and 2014 forecasts is that the current forecast projects higher residential energy usage, an increase of 1.6%, while both commercial and industrial sectors are projecting lower energy usage over the prior forecast, a combined reduction of 4.4%.

The comparison between the 2014 and 2015 forecasts for summer and winter peaks are shown in ***Table 2.***

Summer Peak

Year	Forecast 2014	Forecast 2015	Difference MW	Difference %
2015	46,719	46,452	-267	-0.6%
2016	47,615	47,304	-311	-0.7%
2017	48,501	48,097	-404	-0.8%
2018	49,147	48,784	-363	-0.7%
2019	49,852	49,498	-354	-0.7%
2020	50,554	50,133	-421	-0.8%
2021	51,263	50,756	-507	-1.0%
2022	52,049	51,378	-671	-1.3%
2023	52,981	52,074	-907	-1.7%

Values are non-coincident peaks

Winter Peak

Year	Forecast 2014	Forecast 2015	Difference MW	Difference %
2015/16	45,668	45,600	-68	-0.1%
2016/17	46,415	46,019	-396	-0.9%
2017/18	47,165	46,412	-753	-1.6%
2018/19	47,692	46,912	-780	-1.6%
2019/20	48,241	47,381	-860	-1.8%
2020/21	48,769	47,794	-975	-2.0%
2021/22	49,323	48,199	-1,124	-2.3%
2022/23	49,934	48,614	-1,320	-2.6%
2023/24	50,584	49,089	-1,495	-3.0%

Table 2

Comparison of 2014 and 2015 Forecasts

One key point presented in ***Table 2*** is that the Region continues to project significant growth in peak load even though that projected growth is less than in the previous forecast. With regard to the 2015/16 winter peak, the 2015 forecast is lower than the 2014 forecast by approximately 0.1%. The 2014/15 winter peak was 42,763 MW which was 1,873 MW (4.2%) below what it was projected to be under normal weather conditions. In order to ensure that the starting point of the forecast is consistent with the latest historical value, an additional year of data is updated in each utility's models and the most recent correlations and associations embedded in the historical data are captured and the models are calibrated accordingly. Over the ten-year forecast horizon, winter peaks are projected to increase by an average of 0.9% per year, compared to 1.4% in the prior forecast.

The actual 2014 summer peak was 45,978 MW which was 0.5% (219 MW) higher than projected. The 2015 projections for summer peak demand, compared to the 2014 forecast, show a decrease in 2015 of 0.6%, (267 MW) lower than projected. Over the last ten years, the peninsular Florida had an average growth in summer peak demand of 0.7% per year from 2005 to 2007, then a decline of 1.1% per year until 2012, and a growth at 2.3% per year in the last two years. The current ten-year projection has growth at 1.4% per year. In the load forecast evaluation process, FRCC ensured that all the utilities also adjusted the starting value of the summer peak demand forecast to account for the most recent correlations embedded in the historical data.

The confidence level that can be placed on these forecasts can be deduced by examining the historical performance of FRCC's forecasts. The summer peak analysis of the forecasted peaks versus the actual peaks, shown in ***Table 3***, indicates that since 2008 there has been a tendency to over-forecast the summer peak demand in the FRCC aggregate ten-year load forecast.

COMPARISON OF SUMMER PEAK FORECASTS TO ACTUAL PEAKS (MW)

Year	Actual Summer Peak (MW)	Forecasted Summer Peaks 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005	45,924	43,495									
2006	45,344	44,680	45,520								
2007	46,525	45,962	46,725	46,878							
2008	44,706	47,108	48,030	48,037	47,364						
2009	46,260	48,344	49,233	49,280	48,181	45,734					
2010	45,564	49,556	50,221	50,249	49,093	45,794	46,006				
2011	44,777	50,796	51,343	51,407	50,284	46,410	46,124	46,091			
2012	43,946	52,055	52,490	52,464	51,499	47,423	46,825	46,658	45,613		
2013	44,549	53,270	53,686	53,548	52,645	48,304	47,469	47,446	46,270	45,668	
2014	45,978	54,524	54,830	54,622	53,641	49,219	48,059	48,228	46,857	46,338	45,759

FORECAST VARIANCE (PERCENT)

Year	Actual Summer Peak (MW)	Forecasted Summer Peaks 2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005	45,924	5.6%									
2006	45,344	1.5%	-0.4%								
2007	46,525	1.2%	-0.4%	-0.8%							
2008	44,706	-5.1%	-6.9%	-6.9%	-5.6%						
2009	46,260	-4.3%	-6.0%	-6.1%	-4.0%	1.2%					
2010	45,564	-8.1%	-9.3%	-9.3%	-7.2%	-0.5%	-1.0%				
2011	44,777	-11.8%	-12.8%	-12.9%	-11.0%	-3.5%	-2.9%	-2.9%			
2012	43,946	-15.6%	-16.3%	-16.2%	-14.7%	-7.3%	-6.1%	-5.8%	-3.7%		
2013	44,549	-16.4%	-17.0%	-16.8%	-15.4%	-7.8%	-6.2%	-6.1%	-3.7%	-2.5%	
2014	45,978	-15.7%	-16.1%	-15.8%	-14.3%	-6.6%	-4.3%	-4.7%	-1.9%	-0.8%	0.5%

Forecast values are non-coincident peaks

Table 3

Comparison of Summer Peak Forecasts to Actual Peaks and Forecast Variance

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 for each of the ten years listed from 2005 through 2014. The bottom half of the 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.

The forecast variance section of the table shown in ***Table 3*** provides additional information. For example, looking at the forecasts prepared in 2005, the summer peak for the first year in the forecast horizon was under-forecasted by 5.6% and under-forecasted by 1.5%, the second year. The year 2005 was an outlier and reflects the effects of the "abnormal" weather in that year.

The summer peak projections made in 2005 for the years 2006 and 2007 show an under-forecasting of summer peaks. This is attributed to the state's rapid economic growth fueled by the overheated housing boom. The housing boom experienced in Florida created an abnormal cyclical upswing for the Florida economy that drove growth above normal trended levels expected in projections completed years earlier. The FRCC's 2006 and 2007 forecasts missed their 2006 and 2007 targets by only -0.4% and -0.8%, respectively. At the time, these predictions were made, the housing boom was near its peak and many forecasters were predicting a correction in terms of a slower rate of expansion. The housing bust now lends some credence that a disequilibrium situation existed in the Florida economy during 2006 – 2007 that would never have been projected.

Similarly, the extent of the sudden and sharp decline in customer growth and energy consumption that occurred in 2008 was not foreseeable in the 2005 through 2008 forecasts. Although FRCC members predicted a slowdown in 2008, the extent of the downturn was more severe than expected. The one year-ahead 2008 summer peak variance was -5.6%. The 2009 summer peak variance versus the 2009 forecast was 1.2%, and the 2010 variance versus the 2010 forecast was -1.0%. The smaller forecast variances in 2009 and 2010 were due to the recalibration of the forecasting models to reflect the economic downturn.

An unpredicted downturn is also evident for the summer peak in 2011. While the economy seemed to be showing signs of a recovery in 2010 and 2011, the reality was that average demand had continued to decline. Loads in 2011, 2012 and 2013 were significantly lower, resulting in a summer peak load variance of -2.9%, -3.7% and -2.5% respectively, compared to forecasts developed earlier in each of these years. Utilities recalibrated their forecasting models to account for the continual declines in per-customer usage which was not being fully captured in the previous forecast models. The load in 2014 was slightly higher than projected by 0.5%, but it is in line with the forecast.

Over the short-term, customer growth and economic conditions can differ from the long-term assumptions used to develop the forecast. Predicting cyclical economic "turning points" is a very difficult part of the utility forecaster's job. The FRCC forecast does not attempt to capture these short-term deviations, but seeks to portray the most likely outcome in terms of projected load for the state of Florida over the next ten years.

COMPARISON OF SUMMER PEAK FORECASTS TO ACTUAL PEAKS (MW)

Year	Actual Winter Peak (MW)	Forecasted Winter Peaks									
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005 / 06	43,202	46,717									
2006 / 07	38,023	47,994	48,296								
2007 / 08	41,495	49,139	49,464	49,526							
2008 / 09	45,590	50,414	50,732	50,737	49,601						
2009 / 10	51,767	51,700	51,678	51,673	50,463	44,446					
2010 / 11	45,876	53,030	52,869	52,780	51,606	45,099	46,235				
2011 / 12	38,318	54,370	53,923	53,872	52,753	46,140	46,821	47,613			
2012 / 13	36,733	55,718	55,086	54,986	53,896	46,971	47,558	48,276	46,864		
2013 / 14	38,842	57,094	56,271	56,155	54,922	47,709	48,219	48,889	46,367	46,456	
2014 / 15	42,763	58,493	57,674	57,468	56,232	48,888	48,992	49,534	47,568	47,161	44,636

FORECAST VARIANCE (PERCENT)

Year	Actual Winter Peak (MW)	Forecasted Winter Peaks									
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
2005 / 06	43,202	-7.5%									
2006 / 07	38,023	-20.8%	-21.3%								
2007 / 08	41,495	-15.6%	-16.1%	-16.2%							
2008 / 09	45,590	-9.6%	-10.1%	-10.1%	-8.1%						
2009 / 10	51,767	0.1%	0.2%	0.2%	2.6%	16.5%					
2010 / 11	45,876	-13.5%	-13.2%	-13.1%	-11.1%	1.7%	-0.8%				
2011 / 12	38,318	-29.5%	-28.9%	-28.9%	-27.4%	-17.0%	-18.2%	-19.5%			
2012 / 13	36,733	-34.1%	-33.3%	-33.2%	-31.8%	-21.8%	-22.8%	-23.9%	-21.6%		
2013 / 14	38,842	-32.0%	-31.0%	-30.8%	-29.3%	-18.6%	-19.4%	-20.6%	-16.2%	-16.4%	
2014 / 15	42,763	-26.9%	-25.9%	-25.6%	-24.0%	-12.5%	-12.7%	-13.7%	-10.1%	-9.3%	-4.2%

Forecast values are non-coincident peaks

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

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 because since 1999 there has been only two years, 2003 and 2010, with normal or colder than normal winter seasons for the State of Florida as a whole. A good example of this volatility can be seen comparing the actual peaks of 2006/07 and 2009/10. Winter 2006/07 had a mild winter and the total winter demand of electricity was 5,179 MW (12%) lower than in the prior winter. Conversely, winter 2009/10 was very cold and the winter demand for electricity reached a record of 51,767 MW of peak winter demand. The 2009/10 winter peak load was 6,177 MW (14%) above the prior winter's peak and 7,321 MW (16.5%) above the forecasted winter peak. This extremely high winter peak was the result of the high saturation of heating appliances in use as customers attempted to stay warm when temperatures dipped lower than had been experienced in many years. Temperatures on the winter peak day ranged from 17 to 38 degrees Fahrenheit throughout the state.

Florida does not experience a cold winter very often. Nevertheless, each utility in its resource plan considers the eventuality of a severe winter peak and plans for it. The winter of 2009/10 turned out to be the coldest winter on record (or very close) in many areas of peninsular Florida. Utilities utilized a number of their load management/demand response programs in order to serve their firm load throughout the peak load period. Conversely, the 2014/15 winter peak was 4.2% below forecast due to mild weather during the winter months.

Finally, ***Table 5*** shows a comparison between the historical load factors (for 2005 through 2014), and the projected load factors (for 2015 through 2024), 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 Net Energy for Load.

FRCC LOAD FACTORS
Based on Summer Peak

Historical Year	Load Factor	Forecasted Year	Load Factor
2005	0.563	**2015**	0.565
2006	0.579	**2016**	0.564
2007	0.571	**2017**	0.560
2008	0.579	**2018**	0.559
2009	0.558	**2019**	0.558
2010	0.584	**2020**	0.558
2011	0.571	**2021**	0.555
2012	0.574	**2022**	0.553
2013	0.568	**2023**	0.550
2014	0.558	**2024**	0.548

Table 5
FRCC Load Factors

In summary, 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

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 through TPL-004. These studies include long-range transmission studies and seasonal assessments as well as additional sensitivity studies as needed to address specific issues (e.g., extreme summer weather, off-peak conditions), interconnection and integration studies, and interregional assessments.

The results of the short-term (first five years) study of the FRCC Region for normal, single, and multiple contingency events show that potential thermal and voltage constraints occurring within the FRCC Region are capable of being managed successfully by operator intervention. Such operator intervention can include: generation re-dispatch, system reconfiguration, reactive device control, load shed, and transformer tap adjustments. The majority of planned additions or changes to the FRCC transmission system are related to planned generation expansion and expected load growth.

In addition, the transmission expansion plans representing the longer-term study are under review by most transmission owners (TOs) who are still considering multiple alternatives for each project. Therefore, because specific transmission projects have not been identified or committed to by TOs, these projects are not incorporated into the load flow databank models. The results show local loading trends throughout the FRCC Region as expected given the uncertainties discussed above. No major projects requiring long lead times have been identified.

9.0 FRCC Fuel Reliability

The *FRCC Generating Capacity Shortage Plan*[12] distinguishes between generating capacity shortages caused by abnormally high system loads and unavailable generating facilities from those caused by short-term, generating fuel availability constraints. Since a significant portion of electric generation within Florida uses remotely supplied natural gas, the plan specifically distinguishes generating capacity shortages by primary causes (e.g., hurricane impacts to fuel or abnormally high loads) in order to provide more effective Regional coordination. The FRCC plan also includes specific actions to address capacity constraints due to natural gas availability constraints and includes close coordination with the pipeline operators serving the Region. The FRCC Operating Committee procedure, *FRCC Communications Protocols – Reliability Coordinator, Generator Operators and Natural Gas Transportation Service Providers*[13], provides details regarding coordination between the FRCC Reliability Coordinator and the natural gas pipeline operators. In addition, the FRCC Operating Reliability Subcommittee, through its Fuel Reliability Working Group 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 Reliability Coordinator (RC) have the ability to assess Regional fuel supply status by initiating Fuel Data Status reporting by operating entities. This process relies on entities 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 and is provided on a Regional basis to the RC and SCEC. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and the results of the reporting are quickly integrated into an enhanced *FRCC Daily Capacity Assessment Procedure & Definitions* 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 Regional fuel supply issues and/or disruptions on BES facilities and customers.

Currently, the expected percentage of generation capacity (MW) whose primary fuel is natural gas is projected to reach 69.2% by 2024. A similar long-term forecast projects coal-fired generation to account for 13.6% of capacity, nuclear generation for 6.0%, and oil-fired generation for 9.3% of generation resources. About 1.7% of capacity generation is fueled from Municipal Solid Waste (MSW), Inter-Regional interchange, and miscellaneous fuels.

In regard to 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 and will reach 64.7% by 2024.

With no native gas production or storage, two major pipelines deliver more than 90% of the natural gas to peninsular Florida. The existing pipeline capacity within the Region supports the current generating capacity needs of the Region. In the event of a short term failure of key elements of natural gas delivery infrastructure,

[12]FRCC Handbook – FRCC Generating Capacity Shortage Plan (https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/FRCC%20Generating%20Capacity%20Shortage%20Plan.pdf)

[13]FRCC Handbook – FRCC Communications Protocols -Reliability Coordinator, Generator Operators, and Natural Gas Transportation Service Providers (https://www.frcc.com/handbook/Shared%20Documents/EOP%20-%20Emergency%20Preparedness%20and%20Operations/Comm_Protocols_RC_GO_Natural_Gas_TSPs.pdf)

there is sufficient back up fuel capability to meet projected demand. However, additional coordination may be required in the event of a long-term failure of key elements of natural gas delivery infrastructure.

Regional operators continue to utilize mitigation strategies to minimize the effects of short-term supply impacts due to extreme weather during peak load conditions. These strategies include 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 BES reliability during peak periods and/or during extreme weather conditions in the near-term.

10.0 FRCC Renewables 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."

Thirty-eight states across the nation have a Renewable Portfolio Standard (RPS) or Renewable Portfolio Goals as of April 2014. 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. In 2014, electricity from renewable energy resources made up approximately 1.5% of Florida's net energy (GWh) generation. In Florida there is only a minimal contribution from hydro-electric and wind sources. By comparison, on a national level, hydro-electric and wind sources provide over 10.7% of the net energy generation. Excluding hydro-electric and wind energy, approximately 2.4% of the U.S. net energy production came from renewable energy generating resources in 2014.

Florida's renewable energy electric production is largely derived from biomass materials such as agricultural waste products and wood residues, plus MSW. The biomass and MSW categories combined constitute 77.0% of the renewable energy (GWh) produced in Florida. The remaining significant categories are landfill gas at 10.1%, solar at 7.5%, with hydro-electric and other renewable resources at 5.4%. See ***Figure 6*** and ***Figure 7*** for a breakdown of the state's and nation's renewable energy generation in 2014.

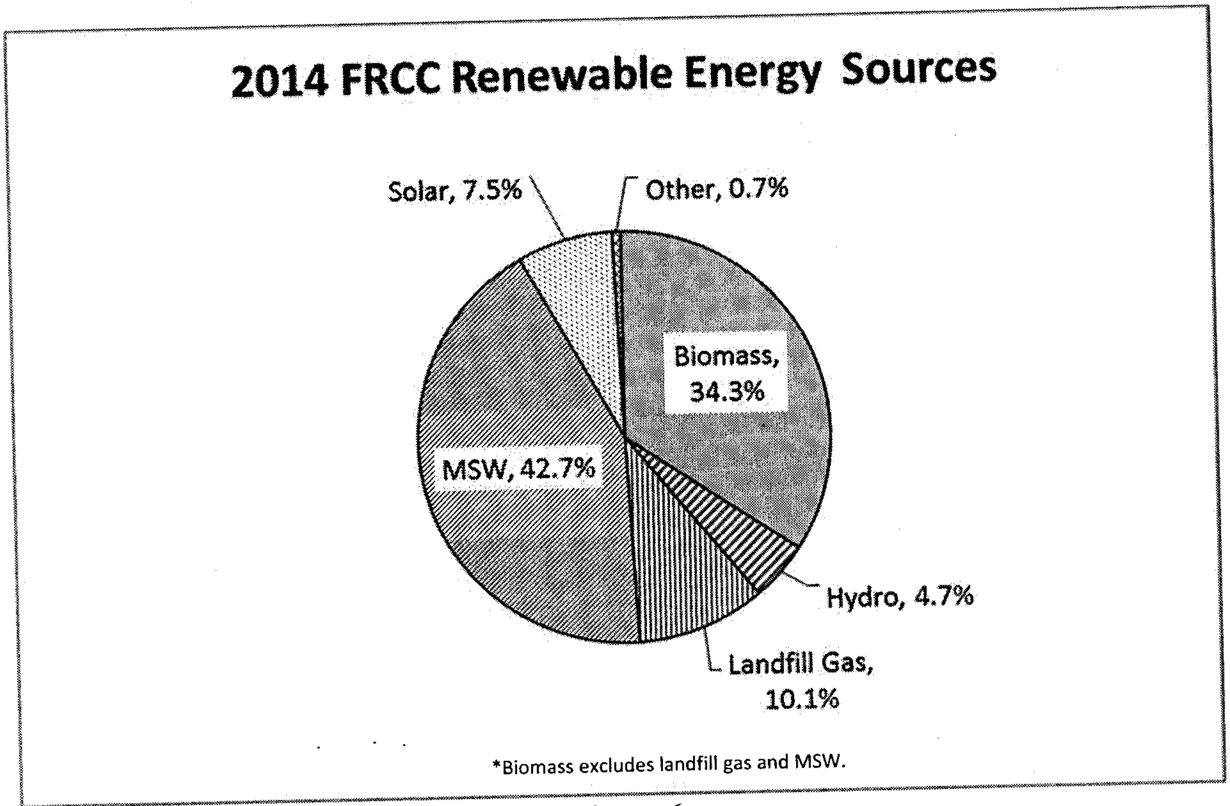

Figure 6
2014 FRCC Renewable Energy Sources

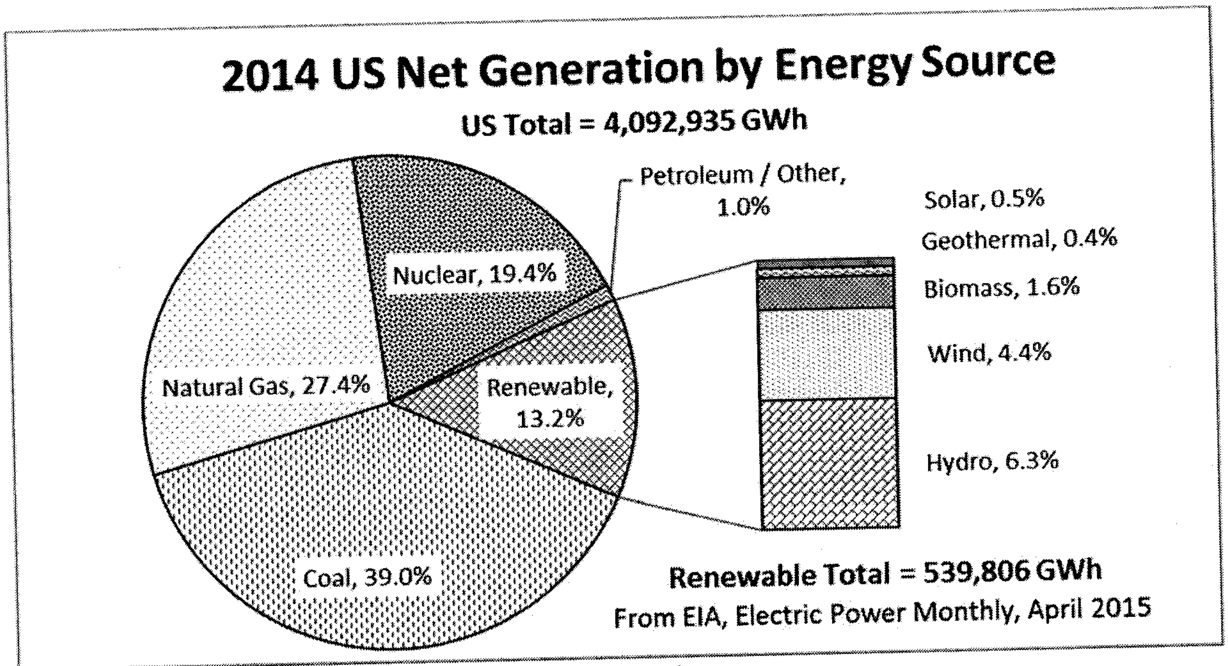

Figure 7
2014 US Net Generation by Energy Source

11.0 References

11.1 *2015 Regional Load & Resource Plan*

12.0 Review and Modification History

Review and Modification Log			
Date	Version Number	Description of Review or Modification	Sections Affected
	1		All

13.0 Disclaimer

This supporting document may explain or facilitate implementation of one or more NERC Reliability Standard requirements but does not contain any explicit mandatory requirements subject to compliance enforcement. The requirements and 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 procedure.

The FRCC committees may revise or terminate this document at any time at its discretion without notice. However, every effort will be made by the FRCC committees to update this document and inform its users of changes as soon as practicable. 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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B

2014 Bulk Electric System Long Range Transmission Study Report – Regional Plan*

Years 2015 – 2025

FRCC
Florida Reliability Coordinating Council, Inc.

Prepared by TWG	September 2014
Approved by PC	December 2, 2014
Approved by BOD	February 17, 2015

* CEII Information Removed

2014 FRCC Bulk Electric System Long Range Study

Table of Contents

Attachments:

2014 FRCC Bulk Electric System Long Range Study

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I. EXECUTIVE SUMMARY

The Florida Reliability Coordinating Council, Inc. (FRCC) Transmission Working Group (TWG) has completed the Region's annual near-term and longer-term steady-state study representing study years 2015 through 2025. This report represents the TWG's compilation and analysis of Bulk Electric System (BES) performance within the FRCC Region in accordance with Table 1 of the NERC Reliability Standards TPL-001-0.1, TPL-002-0b and TPL-003-0b. Background information, methodology, analysis, planned projects, and remedial operational actions are contained within this report.

This study includes an evaluation of a series of load flow cases (models) representing the transmission system at various points in time to aid in demonstrating that the reliability of 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 (2015-2020) and longer-term (2021-2025) planning horizons. All transmission facilities rated 69 kV and above are represented in the load flow databank cases. The models also include real and reactive power resources supplying forecasted real and reactive loads to ensure accurate model representations.

The results of this study demonstrate that the FRCC Region is planned and operated such that, with all transmission Facilities in service and with normal (pre-contingency) operating procedures in effect, the transmission system can be operated to 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 A of Table I of NERC Reliability Standard TPL-001-0.1.

The results of single and selected multiple contingency (Category B & C) events identified portions of the transmission system that require corrective action plans in order to respond as prescribed in Table I of NERC Reliability Standards TPL-002-0b and TPL-003-0b. The corrective action plans ensure the FRCC Region transmission system is planned such that it can be operated to supply projected customer demand and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B & C of Table I of NERC Reliability Standards TPL-002-0b and TPL-003-0b. Corrective action plans include remedial actions such as new transmission Facilities, transmission Facility upgrades, Special Protection Systems (SPS), generation re-dispatch, line switching, or other operator actions. Together the planned Facilities and remedial actions ensure BES system performance as required by the NERC Reliability Standards TPL-001-0.1, TPL-002-0b & TPL-003-0b.

II. INTRODUCTION

The mission of the FRCC is to ensure that the Region's BES and its interconnections with adjacent Regional Reliability Organization's (RRO) are reliable, adequate, and secure. The FRCC performs this Regional Reliability Assessment, as documented in this *2014 Bulk Electric System Long Range Transmission Study Report* (Long Range Study), by conducting regional activities related to planning, operations and coordinating activities with intraregional and interregional entities to ensure the transmission reliability of the FRCC Region.

FRCC Regional Entity Transmission Planners (TPs) and Planning Authorities (PAs) annually perform an assessment of their portion of the FRCC transmission system and their ties with adjacent transmission entities with the assistance of FRCC staff. These assessments, including corrective plans, demonstrate the adequacy of the BES within the FRCC Region.

III. PURPOSE

This Long Range Study report details all phases of the annual steady-state study[1] for inclusion in the assessment process.[2] The TWG performs the computer simulations and analyzes the results of these simulations in order to assess the performance of the BES against the NERC Reliability Standards

This Long Range Study communicates the scope, methodology, results, observations and conclusions of the annual study and is provided to the FRCC Planning Committee (PC) and other interested parties as requested. This report serves as a general review of the performance of the existing transmission system and planned transmission expansion within the FRCC Region throughout the planning horizon.

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[2] Consistent with R1.1 and R1.3.2 of NERC TPL-001-0.1, R1.1 and R1.3.3 of NERC TPL-002-0b and TPL-003-0b

IV. SCOPE

Each load flow databank case used in this assessment is evaluated using computer simulations to capture steady-state system performance under NERC Standards Category A conditions and Category B and C events to ensure adequacy and reliability of the FRCC BES for both existing and planned Facilities throughout the planning horizon (2015-2025).[3]

NERC TPL Standards

The adequacy and security of the transmission system is planned in compliance with the NERC TPL Reliability Standards. In general, the TPL Standards require that the transmission system be planned such that it will remain stable and within applicable thermal ratings and voltage limits without cascading outages under normal system conditions, as well as during single and multiple contingency events. These Reliability Standards include (see Appendix D):

- System Performance Under Normal Conditions (TPL-001-0.1)
- System Performance Following Loss of a Single Bulk Electric System Element (TPL-002-0b)
- System Performance Following Loss of Two or More Bulk Electric System Elements (TPL-003-0b).

The standards above provide TPs and PAs with a set of performance requirements for the planning of the transmission system throughout the ten-year planning horizon.

STUDY Outline

The Long Range Study covers both near-term and longer-term portions of the planning horizon. The near-term portion examines planning years one through five, and analyzes in detail specific remedies identified for all thermal and/or voltage screening criteria exceptions. The longer-term portion examines years six through ten to determine if any trends are developing that would require attention. This is performed to enhance confidence in the entities short-term capital improvement plans. The Long Range Study includes normal conditions (Category A) and single contingency analyses (Category B) that outage and monitor all BES transmission Facilities and identifies any elements that perform outside the screening criteria. In addition, this Long Range Study also includes outages of two or more BES elements identified as follows:

- Bus section failure (Category C1)
- Breaker failure events (Category C2)
- Loss of two independent Facilities with manual system adjustments (Category C3)
- Loss of any two circuits of a multiple circuit tower line (Category C5)

[3] Consistent with R1.2 and R1.3.3 of NERC TPL-001-0.1, R1.2, R1.3.4 of NERC TPL-002-0b and TPL-003-0b

The Methodology section of this Long Range Study discusses the choice of Category C events simulated in the Long Range Study.

NERC defines Year One as the first twelve month period that a TP or a PA is responsible for assessing the Long Range Study. For an assessment started in a given calendar year, Year One includes the forecasted peak load period for one of the following two calendar years. The FRCC Year One will include the forecasted peak load period for the second calendar year. For this Long Range Study, Year One will be 2015.

V. METHODOLOGY

Case Selection

Cases are selected to cover critical system conditions during study years as deemed appropriate by the responsible entity. The study years selected for the longer-term planning horizon are intended to identify marginal conditions that may require longer lead-time solutions. The TWG selected cases to represent the mid-range of the longer-term planning horizon. Study cases include pre-contingency switching (see Appendix F for details), firm transactions and firm resources, as identified by the responsible entities.

Case Assessment

Cases are assessed for possible Rate C exceptions before proceeding with the analysis. Rate C is a proxy rating that can be calculated based on a variety of conditions (pre-load, time, etc.), therefore a higher rating may be available for a Facility for a specified time limit. The cases were assessed by running all contingencies (B, C1, C2, and C5) against the Rate C. The entities address potential screening exceptions using one of four possible 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.).

Confidence level

The major assumptions used in the cases are the forecasted peak real and reactive loads, planned generation dispatch and additions, planned transmission configuration and improvements and projected firm transmission services. The information contained in the cases representing the near-term includes planned projects that have a higher degree of confidence. The confidence level of these major assumptions decreases for the longer-term horizon. Generation plans may not be firm and the location of future generation may be uncertain. Many transmission infrastructure projects in the planning stages may not be represented in the longer-term cases.

Near-term planning horizon

Cases representing the study years in the near-term planning horizon were used to represent summer peak and winter peak critical system conditions.[4] Transmission and generation expansion plans for the first five years have a higher degree of certainty. Planned operator intervention or remedial actions (i.e. projects, SPS, UVLS, etc.) shall be identified during contingency events to restore continuous steady state conditions to within acceptable operating criteria. Available actions that can be performed in a timely fashion can include line switching, changing generation dispatch, transformer tap changing, reactive switching, and load management among others.

Longer-term planning horizon

The cases selected for the longer-term planning horizon are the 2021/22 winter peak case and 2022 summer peak case. These cases represent the mid-range of the longer-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 operator remedial actions.[5] The identification of preliminary proposed projects and the plan to study alternatives can also be acceptable corrective plans for the longer-term horizon.

Demand Level Selection

The Long Range Study includes two load levels (summer peak and winter peak) representing the most critical system condition. Additionally, select off-peak load levels were studied to represent system performance over the range of forecast system demands.[6]

The summer peak season has been identified as the region's most critical system condition and load level due to factors unique to the summer season:

- Most days from May- September experience high load levels
- Load is at a high level for an extended period of time each day.
- Less operating options are available for remedial actions due to high load levels and high generation unit commitment.
- High reactive requirements due to heat pumps for cooling operation.

The winter seasonal peak has also been identified as a regional critical system condition. The winter peak load levels for the region represent the greatest annual real demand; however, winter peaks generally do not occur but a few times and are short lived events. For additional details on study parameters and methodology see Appendix A.

Off-peak load conditions (80% & 60% of summer peak) 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.

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[4] Consistent with R1.2 and R1.3.1 of NERC TPL-001-0.1, R1.2 and R1.3.2 of NERC TPL-002-0b and TPL-003-0b

[5] Consistent with R1.3.4 of NERC TPL-001-0.1, R1.3.4 of NERC TPL-002-0b and TPL-003-0b

[6] Consistent with R1.3.1 and R1.3.6 of NERC TPL-001-0.1, R1.3.2 and R1.3.6 of NERC TPL-002-0b and TPL-003-0b

Inter-Regional Reliability Assessment

The Long Range Study includes an Inter-Regional Reliability Assessment for both the near-term and longer-term portions of the planning horizon. This assessment includes normal conditions (Category A), single contingency (Category B) and multiple contingencies as a result of the loss of two independent transmission Facilities with manual system adjustments (Category C3) for all Facilities within the FRCC Region, transmission tie-lines and identified Facilities within the SERC Region. Three bus levels within SERC Region, are monitored. The assessment also includes additional outages of two or more BES transmission Facilities within the FRCC Region (Category C2 and C5). All BES transmission Facilities within the FRCC Region and the identified Facilities in the SERC Region are monitored for any thermal and/or voltage screening criteria exceptions in all contingency analyses.

Category B events – A single contingency analysis was performed on all BES transmission Facilities within the FRCC Region as well as the identified Facilities within the SERC Region. All Facilities were monitored for any thermal and/or voltage screening criteria exceptions.

Category C2 events - Breaker failure events that resulted in the loss of two or more BES transmission system Facilities were performed for the FRCC Region. All BES Facilities within the FRCC Region and identified Facilities within the SERC Region were monitored for any thermal and/or voltage screening criteria exceptions.

Category C3 events – Loss of two independent Facilities with manual system adjustments for all BES Facilities within the FRCC Region and identified Facilities within the SERC Region.

All BES transmission Facilities within the FRCC Region and identified Facilities within the SERC Region were monitored for any thermal and/or voltage screening criteria exceptions.

Category C5 events – Multiple contingency events involving the loss of any two transmission lines of a multiple tower-line greater than one mile in length and rated 100 kV and above were performed for the FRCC Region. All BES within the FRCC Region and identified Facilities within the SERC Region were monitored for any thermal and/or voltage screening criteria exceptions.

SCOPE OF ANALYSIS

NERC Reliability Standard TPL-001-0.1 requires that the BES be planned such that it will remain stable, within the applicable thermal ratings and voltage criteria, without cascading outages and without controlled loss of demand or curtailment of firm power transfers during Category A conditions. NERC Reliability Standards TPL-002-0b and TPL-003-0b permit planned/controlled loss of demand or curtailment of firm power transfers is as footnoted in Table 1 for Category B and C events. 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

Category A Analysis
For Category A conditions, all BES transmission Facilities are monitored and compared to the 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 are reviewed by the respective entities and case adjustments are 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.[7]

Category B Analysis
For Categories B1, B2 and B3 events, all BES transmission Facilities are singularly removed from service in all study cases.[8] Contingencies resulting in branch loadings exceeding applicable thermal ratings and/or voltage screening criteria are reviewed by the entities. Remedies are then provided by the entities to resolve potential screening criteria exceptions (See Attachment B). This analysis will allow TPs to ensure that future system performance meets Category B event requirements for the BES.

Category B Simulation Study Methodology
The Category B1 – B3 events associated with the TPL-002-0b Standard specify single event outages of transmission lines, transformers or generators 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. In accordance with Requirement R.1.3.10, this analysis includes the effects of existing and planned protection systems, including any backup or redundant systems. The condition of scheduled protection system maintenance is assessed as specified in Requirement R.1.3.12. Given the short duration of protection system maintenance, these maintenance outages are scheduled in the operating time frame and not in the planning horizon.

The TPL-002-0b performance issues for the Category B1 – B3 events which are evaluated in this Long Range Study are confined to steady state loading and voltages following the isolation of the faulted system element

Category B4 was not examined due to the absence of HVDC Facilities within the FRCC Region.

Category C Analysis Selection[9]

[7] Consistent with R1.3.4 of NERC TPL-001-0.1
[8] Consistent with R1.3.1 and R1.5 of NERC TPL-002-0b
[9] Consistent with R1.3.1 and R1.5 of NERC TPL-003-0b

Categories C1, C2, C3 and C5 of Table 1 are used to determine system performance under multiple contingency scenarios that would identify the more severe system impacts on the FRCC BES. See Appendix C - NERC *Category C Event Study Guidelines for FRCC Bulk Electric System* for a discussion on the choice of Category C contingencies for inclusion in the Long Range Study.

Category C1 (Bus Section failure) Analysis. Bus Section failure events that result in the loss of two or more BES transmission system elements that exceed the thermal and/or voltage screening criteria are reviewed by the entities for all near-term and longer-term planning horizon cases. Remedies are provided by entities to resolve potential screening criteria exceptions (See Attachment C).

Category C2 (Breaker failure) Analysis. Breaker failure events that result in the loss of two or more BES transmission system elements that exceed the thermal and/or voltage screening criteria are reviewed by the entities for all near-term and longer-term planning horizon cases. Remedies are provided by entities to resolve potential screening criteria exceptions (See Attachment D).

Category C3 (Lines) Analysis. The 2017 FRCC summer peak load flow databank case was used to evaluate multiple contingency events that result in the loss of two independent transmission elements. All possible BES line combinations 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 are reviewed by the entities and remedies are developed to address any resultant thermal and/or voltage potential screening criteria exceptions (See Attachment E).

Category C3 (Generators) Analysis. FRCC load flow databank cases representing the summer peak 2017 conditions were used to evaluate multiple contingency events that represent the loss of one selected generating unit followed by changes in dispatch and the subsequent loss of one BES transmission element or an additional generating unit. In each individual Balancing Authority (BA) area within the FRCC, new unit out base cases were created for all generators dispatched at 100 MW or greater. Those units were singularly removed from service and the BA's remaining generators were redispatched. Then a full set of category B contingencies were applied. The unit out contingency results were compared to the unit out base case. Those unit out base cases and/or related contingencies with thermal and/or voltage screen criteria exceptions were candidates for further analysis. Unit out cases identified for further analysis were then assessed for multiple contingency analyses. The units included in this further study were:

- CAPE CANAVERAL CC
- LAUDERDALE 4 CC
- LAUDERDALE 5 CC
- MANATEE 3 CC
- PORT EVERGLADES CC
- RIVERIA CC
- SANFORD 5 CC
- TURKEY POINT 5 CC
- CRYST RIVER UNIT 5
- BARTOW CC
- MCINTOSH UNIT 5
- NORTHSIDE UNIT 1
- ST JOHNS UNIT 1
- BRADY BRANCH CC
- HOPKINS 2 CC
- PURDOM 8 CC
- BIG BEND UNIT 2
- POLK 2 CC
- SEMINOLE UNIT 2

Events that cause Facilities to exceed the thermal rating of 100% of Rate B and/or voltage screening criteria were reviewed by the entities. The individual entities provided remedies for the resolution of these potential screening criteria exceptions. (See Attachment E)

Category C5 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 longer-term planning horizon cases used for the Long Range Study. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the entities. Remedies are provided by entities to resolve potential screening criteria exceptions (See Attachment F).

Protection System Analysis. Contingency events resulting in the loss of two or more circuits or elements as the result of existing and planned protection systems[10] rated 100 kV and above are evaluated. Examples of these contingencies events are three terminal lines and events resulting in the loss of appropriate generating units of a combined cycle generator (gas and steam turbine). These contingency Events are simulated in all near-term and longer-term planning horizon cases used for the Long Range Study. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the entities to resolve potential screening criteria

[10] Consistent with R1.3.10 of NERC TPL-002-0b

exceptions (See Attachment F). The contingency loss of individual segments of standard two terminal lines has consistently resulted in more exceptions than corresponding breaker to breaker contingencies.

Review and consideration is given to the potential response of existing and expected future configuration protection systems relative to resultant system conditions following assessed events. Where the potential likelihood of protection system actions are identified, further simulation of those actions are assessed to determine resulting system conditions. (see TPL-002-0b and TPL-003-0b R1.3.10)

Category C and D contingencies are addressed in the FRCC Extreme Event Study[11] performed by the Stability Working Group (SWG). This study tests those Category D events and the Category C protection failure events (Categories C6 through C9) that have the most severe impact on the BES for the 2013 – 2018 planning horizon. No Category C performance violations were identified in the steady-state analysis. 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.

REACTIVE SUPPORT

Existing and planned Reactive Power resources are modeled in all cases to ensure that reactive resources are adequate to meet desired system performance.[12] A Reactive Power resource is any device that can control the transmission system voltage. Reactive Power resources include, but are not limited to, generating units, capacitor banks, synchronous condensers, VAR compensators and reactor banks.

A measure of Reactive Power resource adequacy is Facility voltage levels. As discussed in the Analysis Section, voltages on regional BES Facilities are monitored to ensure voltage criteria are met. Screening of simulation voltage exceptions (those Facilities with voltages outside applicable criteria) allow the TP to assess the adequacy of the region's existing and planned Reactive Power resources under normal conditions.

COORDINATED REMEDIES

Contingencies that result in thermal loading and/or voltage screening criteria exceptions where the remedy requires the involvement of the transmission assets of two or more entities require coordinated remedies. The entities discuss various options, including remedial control, switching of transmission assets and/or coordinated generation

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[11] The FRCC has reviewed the study cases used for the FRCC Extreme Events Study dated December 30, 2013 and confirms these study cases continue to be applicable to the current near term planning horizon cases (2014 – 2018) with respect to the BES performance for the Category C6 – C9 fault scenarios associated with the TPL-003-0b Reliability Standard. This assessment is based on the topology of the BES as well as the overall load and generation dispatch levels within the Region. In addition, planned generation in the FRCC Region is studied as part of the FRCC Regional Transmission Planning Process which includes analysis of the effects of the Category C6 – C9 fault scenarios on the area of the transmission system in which generation additions are planned.

[12] Consistent with R1.3.9 of NERC TPL-001-0.1, TPL-002-0b and TPL-003-0b

redispatch, in order to develop coordinated remedies that address the transmission concerns.

CORRECTIVE PLAN

During the performance of these studies, new system criteria exceptions might occur. It is incumbent on the entity with the Facility rating criteria exception to resolve the criteria exception. Each entity provides a mitigation plan addressing each criteria exception. Criteria exceptions that cannot be resolved by operational remedies require Facilities to be planned to ensure future transmission adequacy.

VI. RESULTS AND OBSERVATIONS

The results of this Long Range Study for normal, single and multiple contingency events within the FRCC Region meet NERC Reliability Standards and adhere to the FRCC Planning Process. The results of this Long Range Study are discussed separately in the near-term and longer-term sections.

NEAR-TERM

The Long Range Study shows that for Category A conditions and Category B and C events, the performance of the transmission system is adequate and in compliance with NERC Transmission Planning Standards for the near-term planning horizon.

LONGER-TERM

The Long Range Study for the longer-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. Therefore, the remedies developed to address concerns identified within the longer-term planning horizon are subject to the uncertainty of generation and transmission expansion plans and the location and timing of projected loads. In addition, the transmission expansion plans representing the longer-term of this Long Range Study are typically under review by most entities still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most entities, these projects are not incorporated into the load flow databank models. The results of this Long Range Study for the Longer-Term horizon show local loading trends throughout the FRCC Region as expected given the uncertainties discussed above. No major projects requiring long-lead times were identified.

Based upon a review of the Long Range Study results, the results of the Category C3 (Lines) 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 TPL Standards.

INTER-REGIONAL RELIABILITY ASSESSMENT

The results for normal, single and multiple contingency events for Facilities within the FRCC Region and identified Facilities within the SERC Region show no performance exceptions to the criteria of the NERC TPL Standards. No FRCC or SERC contingency events resulted in a transmission Facility screening criteria exception.

VII. CONCLUSION

The Long Range Study of the 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 TPL Standards. These remedies were reviewed by the entities and found to be adequate in order to maintain acceptable system performance under Category A conditions and Category B and C events.

Attachment A: Remedies for Normal Conditions (A)

Pages contain CEII information and are not included

Attachment B: Remedies for Single Contingencies (B)

Pages contain CEII information and are not included

Attachment C: Remedies for Bus Section Failures (C1)

Pages contain CEII information and are not included

Attachment D: Remedies for Breaker Failures (C2)

Pages contain CEII information and are not included

Attachment E: Remedies for Selected Double Contingencies (C3)

Pages contain CEII information and are not included

Attachment F: Remedies for Double Circuit Contingencies (C5)

Pages contain CEII information and are not included

Attachment G: B Protection, Combined Cycle, C2, and C5 Contingency Look-up Tables

Pages contain CEII information and are not included

Attachment H: Rate C Screening (B, C1, C2, & C5)

Pages contain CEII information and are not included

Attachment I: 69kV Evaluation on Potential Rate C Violations

Pages contain CEII information and are not included

Attachment J: Resolution of "No Solve"

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 2016, 2017 (peak, 80%, 60%), 2018, 2019, 2020, 2022 and winter 2015/16, 2016/17, 2017/18, 2018/2019, 2019/20, 2021/22 as represented in the FRCC FY14 load flow databank case.
  - 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.

- Generation and load are represented in MW and MVAr in all study cases.

- 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.

- 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 C3. Category C3 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.

- All projected contracted Firm (non-recallable reserved) transmission services are included in the case interchange schedules as specified by the parties engaged in each the transaction.[1]

- All LTC transformer taps are locked except those of Duke Energy Florida to simulate t = 0+ conditions.

- Generators are forced to control the voltage of the low-side bus to simulate actual conditions.

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[1] Consistent with R1.3.5 of NERC TPL-002-0b and TPL-003-0a

- Modeling of events included the response of existing and planned controlled devices as reported by the owner of the device.[2] 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).

- Includes all existing and planned transmission Facilities, generating units, and Reactive Power resources in the base cases.[3]

- Includes the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. This is done at the transmission entity level.[4]

- Includes all existing and planned protection systems, including backup and redundant systems[5].

- Incorporates the applicable Nuclear Plant Interface Requirements (NPIR) provided by transmission entities responsible for providing services related to NPIRs[6].

A.2 – Methodology

The FRCC summer 2016, 2017 (peak, 80%, 60%), 2018, 2019, 2020, 2022 and winter 2015/16, 2016/17, 2017/18, 2018/2019, 2019/20, 2021/22 load flow databank cases 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 A 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.

Normal (N) and Single Contingency (N-1) Analysis

NERC Reliability Standards TPL-001-0.1 and TPL-002-0b state that the transmission system will remain in a stable state, within the applicable thermal and voltage ratings, and without cascading outages, during normal conditions (N) and after single contingency (N-1) conditions for the time period specified. Appendix D of this report contains the applicable NERC Reliability Standards. Table I of these Standards describes categories A and B1 – B3 that are the basis for the normal (N) and contingency (N-1) steady-state analysis of the FRCC Region. For this study, all control areas within the FRCC Region are monitored for potential Rate B SOL and voltage exceptions. All 100kV and above

[2] Consistent with R1.3.11of NERC TPL-002-0b and TPL-003-0a
[3] Consistent with R1.3.8 of NERC TPL-001-0.1, TPL-002-0B and TPL-003-0a
[4] Consistent with R1.3.12 of NERC TPL-002-0b and TPL-003-0a
[5] Consistent with R1.3.10 of NERC TPL-002-0b, TPL-003-0a

[6] Consistent with R3 of NERC NUC-001-2

Facilities are singularly outaged and observed for voltages outside the general screening criteria of 95% - 105%, or the specific criteria of individual utilities. Branches connected to these buses are monitored for overloads above their Rate A for Category A and Rate B for Category B. Any contingencies that resulted in branch loadings exceeding 100% of the Rate B or bus voltages outside the general screening criteria are summarized using the TARA software. The resulting TARA summaries of the various failed contingencies for each scenario are contained in Section II. The FRCC TWG members reviewed the results that had an effect on their control area and provided remedies for the resolution of these potential exceptions. These remedies have been included with the TARA summaries. Any contingency producing exceptions of the branch loading or bus voltage criteria that cannot be remedied is noted as an exception in the final assessment. If any contingency events result in a "No Solution" condition that cannot be resolved by the TWG, these contingency are referred to the SWG for further study to determine whether system stability is compromised.

Category B Simulation Study Methodology

The Category B1 – B3 events associated with TPL-002-0b Standard specify single event outages of transmission lines, transformers or generators 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. In accordance with Requirement R.1.3.10, this analysis should include the effects of existing and planned protection systems, including any backup or redundant systems. The standing practice within the FRCC Region is to cover all BES Facilities with high speed protection for fault conditions such as three phase or single line to ground. High speed clearing is in the range of three to five cycles with the relay systems and circuit breaker interrupting times used for BES Facilities. Given the system protection practices used in the FRCC and the normal operation of the primary high speed protection, backup protection systems will not operate for normally cleared faults on the BES. The condition of scheduled protection system maintenance is assessed as specified in Requirement R.1.3.12. Given the short duration of protection system maintenance, these maintenance outages are scheduled in the operating time frame and not in the Planning Horizon.

The TPL-002-0b Standard requires stable transmission system performance following the specified normally cleared faults. Electrical faults that exceed normal clearing times may cause stability problems in the interconnected transmission system due to the depressed voltage during the fault. If the fault is near a generator, this depressed voltage reduces the MW output of the generator, which creates an imbalance between the mechanical input and the electrical output of the generator. If the fault is on the system long enough, the generator will experience enough acceleration that it cannot retain synchronism. There are no stability issues in the FRCC Region for normally cleared faults due to the short duration of the fault and the tightly meshed interconnections of the generating plants.

Stability problems may be caused by longer duration faults caused by protection system failures associated with the TPL-003-0 and TPL-004-0 Standards. The most severe fault with protection failure contingencies are studied annually by FRCC Stability Working Group. Those delayed clearing faults that cause stability issues have been simulated as normally cleared faults. The response of the BES within the FRCC Region is stable for normally cleared faults studied. The TPL-002-0 performance issues for the Category B1 – B3 events are confined to steady state loading and voltages following the isolation of the faulted system element. The FRCC uses large scale steady state simulation methods that test all BES Facility outages in its TPL-002-0 transmission assessments. Dynamic simulation methods are used to analyze protection system failure events. When the protection failure event results in a stability issue, the event is also simulated as normally cleared fault event.

Multiple Contingency (N-2 and greater) Analysis
NERC Reliability Standard TPL-003-0b states that even with events resulting in the loss of two or more elements, the BES will remain stable, within thermal and voltage limits, and without cascading outages, with some controlled loss of demand or curtailment of firm power transfers. Appendix D of this report contains the applicable NERC Reliability Standards. Categories C1, C2, C3 and C5 from Table I are to be used for the multiple contingency steady-state analysis of the FRCC system.

Category C1 contingencies model bus section fault events that result in the loss of two or more transmission system elements. Each entity compiles a list of such Facilities rated 100kV and above. The affected elements are modeled and a full A.C. load flow analysis is conducted to determine if the system remains within the applicable thermal and voltage limits, with limited planned/controlled loss of demand or curtailment of firm power transfers. All control areas within the FRCC Region are monitored for potential thermal and voltage exceptions and include buses 100kV and above which are observed for bus voltages outside the screening criteria. Branches connected to these buses are monitored for loadings above their Rate B or emergency ratings (based on rated current). Attachment B contains the results of this analysis along with appropriate corrective actions. Any unresolved problems are included as exceptions in the final report. If any contingency events result in a "No Solution" condition, these contingency events are referred to the SWG for further study to determine whether system stability is compromised.

Category C2 contingencies model breaker failure events that result in the loss of two or more transmission system elements. Each entity compiles a list of such Facilities rated 100kV and above. The affected elements are modeled and a full A.C. load flow analysis is conducted to determine if the system remains within the applicable thermal and voltage limits, with limited planned/controlled loss of demand or curtailment of firm power transfers. These types of contingencies can result in islanding when loads become isolated from the transmission grid and are identified as such in the results. All control areas within the FRCC Region are monitored for potential thermal and voltage exceptions and include buses 100kV and above which are observed for bus voltages outside the screening criteria. Branches connected to these buses are monitored for loadings above their Rate B or emergency ratings (based on rated current). Attachment C contains the results of this analysis along with appropriate corrective actions. Any unresolved problems are included as exceptions in the final report. If any contingency events result in a "No Solution" condition, these contingency events are referred to the SWG for further study to determine whether system stability is compromised.

The peak load 2017 summer season was selected by the FRCC TWG for the more detailed Category C3 steady-state portion of this study. One year (two seasons) in the near term is studied annually under Category C3 events, namely the summer 2017 (peak and 80%) and winter 2016/2017 seasons. The FRCC TWG selected a single year for the testing of Category C3 events to allow for a more in depth analysis. System performance in summer 2017 is expected to be similar to the performance in years 2015 and 2016, therefore summer 2017 was used to represent the near term. Years beyond 2017 become less certain in terms of planned projects and transactions, therefore performing an in depth study of these years would provide information of limited value. Summer 2017 allows adequate lead time to address potential system performance concerns related to Category C3 events. Using the PowerGEM's TARA software, the FRCC Region was evaluated with all combinations of lines 100 kV and above within the Region. Double contingency outages causing line loadings greater than 100% of Rate C or bus voltages less than 0.88 per unit were identified as candidates for further evaluation.

A number of the candidate contingencies, when evaluated as single contingencies, caused thermal or voltage exceptions. For these candidate contingencies, each member developed remedies to address any thermal or voltage exceptions. Those candidate contingencies, when evaluated as single contingencies, that resulted in thermal and/or voltage exceptions were modeled as individual events with the necessary system reconfiguration prior to the next contingency event. Each member reviewed the candidate contingencies and developed remedies to address any thermal and/or voltage exceptions. In addition, any candidate contingency that results in excessive loading and wide spread low voltages was treated as a contingency that had the potential to create a cascading outage, and was reported to the SWG for further evaluation. The results of the C3 evaluation can be found in Section V.

Category C5 contingencies involve the loss of double circuit towerlines. The FRCC members identified all such circuits 100kV and above and greater than one mile in length. These Category C5 events are singularly outaged using full A.C. load flow analysis to determine if the system remains within the applicable thermal (based on rated current) and/or voltage screening criteria, with limited planned/controlled loss of demand or curtailment of firm power transfers. Section IV contains the list of lines studied, the results and any appropriate corrective action plans. Any unresolved problems are included as exceptions in the final report. If any contingencies result in a "No Solution" condition, they are referred to the SWG for further study to ensure that system stability is not compromised.

Emergency Ratings and System Operating Limits

In accordance with TPL-001-0.1, TPL-002-0b, TPL-003-0b, 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 Plan

In accordance with TPL-001-0.1, TPL-002-0b and TPL-003-0b, a Corrective Plan (CP) must be submitted annually to the Regional Reliability Organization (RRO) if requested. TPL Standards require that annual assessments which include CPs when system simulations indicate an inability of the systems to respond as prescribed in the standards. A summary of these CPs are provided as part of the remedy response for identified screening criteria exceptions. These remedies include a written summary of the plans to achieve the required system performance as described above throughout the planning horizon. Additionally, each remedy includes an expected in-service date for the proposed Facilities. The base case models include existing and planned Facilities.

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 (B, C1, C2, C5, C3 Gens) 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 from exceeding the SOL.

Step 2: Re-run cases with all supplied corrections against Rate C for contingencies (B, C1, C2, C5, & C3 Gens). 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.

Option2: 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 100kV Rate C Potential Violations

Screen for BES impact by modeling the contingency as well as all of the 100kV 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 100kV Facilities - Document as no impact on the BES and no further action is required.

CAT 3: Rate A BES Overload appears – The original 100kV 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 100kV Rate C Overloads appear – Outage the highest 100kV Rate C overload and evaluate the results using the above categories.

Appendix C - NERC Category C Event

Study Guidelines for FRCC Bulk Electric System

The FRCC periodically conducts power flow and dynamic simulation studies to test those Category C and D contingencies that would produce the most severe grid response. These studies are performed by the Transmission Working Group (TWG), which focus on power flow analysis, and by the Stability Working Group (SWG), which focuses on simulation studies and transmission grid stability. The rationale for the contingencies periodically studied by the TWG and SWG is explained in this document.

Category B Simulation Guides

B1. SLG fault on a generator with normal clearing
B2. SLG fault on a transmission circuit with normal clearing
B3. SLG fault on a transformer with normal clearing
B4. HVDC single pole block

For the Category B1 – B3 normal clearing fault events, the normal study practice is to simulate the loss of the element without a fault since dynamic simulations of Category C faults with delayed-clearing (C6-C8) typically produce a more severe impact than the Category B fault events. Category B4 is not presently applicable to the FRCC Region due to the absence of HVDC Facilities.

Category C Simulation Guides

C1. SLG fault on a bus section
C2. SLG fault on a breaker
C3. SLG fault (line generator, transformer) with another Facility outaged
C4. HVDC bipolar block
C5. Double circuit tower outage
C6. SLG fault on generator with protection failure
C7. SLG fault on transformer with protection failure
C8. SLG fault on line with protection failure
C9. SLG fault on bus with protection failure

Category C4 is not presently applicable to the FRCC Region due to the absence of HVDC Facilities.

Category C1, C2, C3, and C5 contingencies are normally screened with power flow methods by the TWG as their potential adverse effect can be studied under steady state post fault conditions. Dynamic simulation studies are conducted for those Category C2, C3 and C5 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).

Category C and D contingencies are addressed in the FRCC Extreme Event Study[7]. performed by the Stability Working Group (SWG). This study tested those Category D events and the Category C protection failure events (Categories C6 through C9) that have the most severe impact on the BES for the 2014 – 2018 planning horizon. No Category C 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.

[7] The FRCC has reviewed the study cases used for the FRCC Extreme Events Study (dated December 30, 2013) and confirms these study cases continue to be applicable to the current near term planning horizon cases (2014 – 2018) with respect to the BES performance for the Category C6 – C9 fault scenarios associated with the TPL-003-0a Reliability Standard. This assessment is based on the topology of the BES as well as the overall load and generation dispatch levels within the Region. In addition, planned generation in the FRCC Region is studied as part of the FRCC Regional Transmission Planning Process which includes analysis of the effects of the Category C6 – C9 fault scenarios on the area of the transmission system in which generation additions are planned

Appendix D - NERC TPL Standards, Table I Reference

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	 Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c]	 No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix E - NERC TPL Document Reference

Standard TPL-001-0.1 — System Performance Under Normal Conditions	Section	Page
B. Requirements		
R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to 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 A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:	Entire report	-
R1.1. Be made annually.	II	2
R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	I IV V	1 3 4
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).	IV Attachment A	3
R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.	V	4 & 5
R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.	II	2
R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	IV V	3 5
R1.3.4. Have established normal (pre-contingency) operating procedures in place.	I IV V	1 3 7
R1.3.5. Have all projected firm transfers modeled.	Appendix A	
R1.3.6. Be performed for selected demand levels over the range of forecast system demands.	V	5
R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).	V Attachment A	7
R1.3.8. Include existing and planned facilities.	V Attachment A	5
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.	V	10
R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.	Attachment A	
R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1_R1, the Planning Authority and Transmission Planner shall each:	Attachment A	
R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.	Attachment A	
R2.1.1. Including a schedule for implementation.	Attachment A	
R2.1.2. Including a discussion of expected required in-service dates of facilities.	Attachment A	
R2.1.3. Consider lead times necessary to implement plans.	Attachment A	
R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	Appendix A	
R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	Entire report	

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element	Section	Page
B. Requirements		
R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:	Entire report	
R1.1. Be made annually.	II	2
R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	I IV V	1 3 4
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	IV Attachment B	3
R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	V	7
R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.	V	4 & 5
R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.	II	2
R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	IV V	3 5
R1.3.5. Have all projected firm transfers modeled.	Appendix A	
R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.	V	5
R1.3.7. Demonstrate that system performance meets Category B contingencies.	Attachment B	
R1.3.8. Include existing and planned facilities.	V Appendix A	5
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources	V	10
R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.	V	9 & 10
R1.3.11. Include the effects of existing and planned control devices.	Appendix A	
R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.	Appendix A	
R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.	Attachment B	
R1.5. Consider all contingencies applicable to Category B.	V	7
R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b_R1, the Planning Authority and Transmission Planner shall each:	Attachment B	
R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	Attachment B	
R2.1.1. Including a schedule for implementation.	Attachment B	
R2.1.2. Including a discussion of expected required in-service dates of facilities.	Attachment B	
R2.1.3. Consider lead times necessary to implement plans.	Attachment B	
R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	Appendix A	
R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.	Entire report	

Standard TPL-003-0B — System Performance Following Loss of Two or More BES Elements	Section	Page
B. Requirements		
R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (nonrecallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:	Entire report	
R1.1. Be made annually.	II	2
R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.	I IV V	1 3 4
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).	IV Attachments C - F	3
R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.	V	7
R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.	V	4 & 5
R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.	II	2
R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.	IV V	3 5
R1.3.5. Have all projected firm transfers modeled.	Appendix A	
R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.	V	5
R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.	Attachments C - F	
R1.3.8. Include existing and planned facilities.	V Appendix A	5
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.	V	10
R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.	V	9 & 10
R1.3.11. Include the effects of existing and planned control devices.	Appendix A	
R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.	Appendix A	
R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.	Attachments C - F	
R1.5. Consider all contingencies applicable to Category C.	V	8, 9 & 10
R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0B R1, the Planning Authority and Transmission Planner shall each:	Attachments C - F	
R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:	Attachments C - F	
R2.1.1. Including a schedule for implementation.	Attachments C - F	
R2.1.2. Including a discussion of expected required in-service dates of facilities.	Attachments C - F	
R2.1.3. Consider lead times necessary to implement plans.	Attachments C - F	

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.	Appendix A	
R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.	Entire report	

Appendix F - List of Pre-Contingency Switching

Pages contain CEII information and are not included

APPENDIX G - 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. (Regional Reliability Organization)

City of Homestead
City of Tallahassee
City of Vero Beach, represented by Orlando Utilities Commission
Florida Keys Electric Cooperative Association
Florida Municipal Power Agency representing:
- Beaches Energy Services
- City of Clewiston
- Fort Pierce Utility Authority
- City of Green Cove Springs
- Keys Energy Services
- Kissimmee Utility Authority
- Ocala Utility Services
- Florida Municipal Power Agency

Florida Power & Light Company
City of Gainesville d/b/a Gainesville Regional Utilities
JEA
Lakeland Electric
Lake Worth Utility
Lee County Electric Cooperative, Inc.
Orlando Utilities Commission
Duke Energy Florida
Reedy Creek Improvement District
Seminole Electric Cooperative, Inc.
Tampa Electric Company
Utilities Commission of New Smyrna Beach

C

Florida Transfer Capability Assessment:

Projections for 2016 Assessment Year

*Report**
April, 2015

*(*CEII Information Removed)*

TRANSFER CAPABILITY ASSESSMENT: FLORIDA / SOUTHERN INTERFACE

Projections for 2016 Assessment Year

Report
April, 2015

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April 7, 2015

SUMMARY

The projected transfer capabilities between the FRCC Region (Florida) and the Southern Balancing Authority within the Southeastern subregion of the SERC region (Southern) have been assessed by the Florida owners of the Florida/Southern transmission interface and are documented in this report. A more detailed summary of assessment results is given in Appendix A. The Near-Term Transmission Planning Horizon values shown in Table 1 are given for informational purposes. These assessment values were determined in accordance with the interface methodologies and criteria of the importing utilities for determining interface capability. These assessment values can be utilized for screening purposes to identify potential future transmission system limiting facilities that could impact Bulk Electric System's ability to reliably transfer energy in the Near-Term Transmission Planning Horizon. A detailed analysis using the then 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 transmission interface are dependent on the specific sources and sink combinations that comprise the total transfer and as such may require a specific study.

The 2016 summer transfer capabilities are representative of the June through September time period and the 2016/2017 winter transfer capabilities are representative of the December through February time period. Note that various operating procedures, which are documented in Appendix B, are required to achieve these results.

Changes in transfer capability are due to modifications to SEGLV at PEEC and changes to transmission expansion plan in Southern company.

Table 1 Season	Transfer Capability (MW) SOU to Fla	Fla to SOU
2016 Summer	3200	800
2016/17 Winter	3200	1100

INTRODUCTION

The primary purpose of this analysis effort is to perform an assessment of the Florida / Southern transmission interface for the Near-Term Transmission Planning Horizon and to identify potential future transmission system limiting facilities that could impact Bulk Electric System's ability to reliably transfer energy across this interface. The Florida owners of Florida / Southern transmission interface have established criteria for annually assessing the transfer capabilities of this interface in the Near-Term Transmission Planning Horizon[1]. Transfers across the Florida / Southern transmission interface were simulated for the 2016 summer and 2016/2017 winter time periods. Power imports to Florida were evaluated based on the methodologies and criteria of the Florida owners of the transmission interface and respect all known System Operating Limits[2]. Power exports From Florida to the Southern Balancing Authority (SBA) were evaluated consistent with the methodologies and criteria of the SBA.

The Southern models were based on the latest available series of the 2014 SBA base cases. The FRCC models were based on the 2014 FRCC data bank (FY14, rev1). Contingency simulations of the Florida and Southern 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 and generating unit contingencies within the FRCC and Southern Company 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. Some contingencies cause overloads or voltage problems that are not significant for transfers between Southern and Florida. These overloads can be resolved by operating procedures (primarily switching of transmission facilities) that have been reviewed and approved by the impacted transmission system owners. The operating procedures examined in this study are listed in Appendix B.

[1] Consistent with NERC FAC-013-2, R1.1

[2] Consistent with NERC FAC-013-2, R1.2 and R1.3

The methodology used for the determination of Southern to Florida transfer capability assumes all facilities are available and considers all applicable Category B and C contingencies as well as known System Operating Limits. The interchange assumptions for the transfer capability test cases start with firm interchange commitments which reflect current and approved transmission uses[3]. Additional transfers to the FRCC balancing areas with an allocated or assigned right to interface capability are then modeled to increase transfers across the Florida / Southern transmission interface. All transmission paths connecting the FRCC to Southern are part of the Florida / Southern transmission interface consequently there is no need for any loop flow adjustment[4]. Transfers are evaluated by scaling load and generation in the FRCC and Southern Balancing Areas[5]. Test transfer cases are developed in 100 MW increments. Generation is dispatched economically to the extent practical to meet each Balancing Area's scheduled net interchange. The generation dispatch includes long term planned generator outages, additions and retirements as they are known at the time the base cases are developed[6]. The transmission system topology is modeled with the assumption that all facilities are available unless there is a long term planned outage, addition or retirement expected for the assessed seasonal period[7]. System demand is modeled at the projected peak load period for the assessed Planning Horizon scenario as this is known to be the most adverse case for transfer capability[8]. For the voltage stability analysis, key single and double contingencies were tested using a Power/Voltage ("P/V") sensitivity method. For the P/V method generation is scaled in the source system and load is scaled in the sink system[9]. 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.

The methodology used for determination of Florida to Southern export capability assumes the unavailability of a generating unit in Southern with the most significant effect on the interface capability. In the summer and winter seasons it was necessary to reduce load in the exporting systems for Florida to Southern transfers in order to achieve transfer test levels high enough to find a limitation to transfers. It was necessary to reduce load in the FRCC region in order to achieve transfer test levels high enough to find a limitation to

[3] Consistent with NERC FAC-013-2, R1.4.4
[4] Consistent with NERC FAC-013-2, R1.4.5
[5] Consistent with NERC FAC-013-2, R1.5
[6] Consistent with NERC FAC-013-2, R1.4.1
[7] Consistent with NERC FAC-013-2, R1.4.2
[8] Consistent with NERC FAC-013-2, R1.4.3
[9] Consistent with NERC FAC-013-2, R1.5

transfers. The load in the FRCC region was reduced to 90% of the seasonal peak to evaluate Florida to Southern transfers for both the summer and winter seasons. Importing utilities maintain their peak load during these transfers.

System response is modeled to all contingencies[10]. Circuit loading and voltages for all facilities 100 kV and above are monitored in the FRCC Region and the Southern Balancing Area[11]. 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 impacts[12] less than 3% of the applicable facility rating) were not considered limitations to transfers. Additionally, there are some transfer limiting overloads that can be resolved with operating procedures, and are listed in Appendix B.

ASSESSMENT of FLORIDA TO SOUTHERN TRANSFERS

2016 Summer Period

The transfer capability for the 2016 summer peak load scenario that assumes the Vogtle #1 generating unit is unavailable is calculated to be 800 MW. The outage of the Thalmann – McCall Road 500 kV line causes the Hatch - Vidalia 230 kV line to exceed its thermal rating of 486 MVA at higher transfers.

2016/2017 Winter Period

The transfer capability for the 2016/17 winter peak load scenario that assumes the McIntosh #2 combined cycle unit is unavailable is calculated to be 1100 MW. The outage of the West McIntosh – McIntosh 230kV line causes the West McIntosh 500/230kV #2 autotransformer to exceed its thermal rating of 1350 MVA at higher transfers.

[10] Consistent with NERC FAC-013-2, R1.4.6

[11] Consistent with NERC FAC-013-2, R1.4.7

[12] Outage Transfer Distribution Factor (OTDF) - 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 SOUTHERN TO FLORIDA TRANSFERS

2016 Summer Period

The transfer capability for the 2016 summer condition is calculated to be 3200 MW. Higher transfers were found to be limited by voltage security concerns for the outage of the Port Everglades #5 combined cycle unit.

2016/2017 Winter Period

The transfer capability for the 2016/2017 winter condition is calculated to be 3200 MW. Higher transfers were found to be limited by voltage security concerns for the outage of the Port Everglades #5 combined cycle unit.

Table 2 - Critical Plant Outages and Double Contingencies

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

Appendix B
Operating Procedures

Contains CEII information
and is not included