State of Florida

Public Service Commission

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

DATE: August 15, 2012

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Engineering Specialist II, Division of Engineering
Victor Ma, Engineering Specialist I, Division of Engineering
Traci L. Matthews, Government Analyst I, Division of Engineering

RE: FRCC's 2012 Studies and reports for the 2012 TYSP Workshop

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Attached is the Florida Reliability Coordinating Council's 2012 Studies and Reports for the 2012 Ten-Year Site Plan Workshop. Please place this item in Docket No. 120000 – Undocketed Filings for 2012, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact me.

POE

Attachment

FRCC

Florida Reliability Coordinating Council, Inc.

2012
Ten-Year Site Plan Workshop
FRCC Studies and Reports

August 13, 2012

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FRCC
Florida Reliability Coordinating Council, Inc.

FRCC 2012 Load & Resource Reliability Assessment Report FRCC-RE-PL-002 r0 Effective Date – July 10, 2012

Approved By:	Date Approved:
Prepared by FRCC Resource Working Group (RWG) on June 21, 2012 Approved by FRCC Regional Entity Planning Committee (RE PC)	July 10, 2012

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Executive Summary

One of the primary functions of the Florida Reliability Coordinating Council (FRCC) is to assess the reliability of the Bulk Power System in the Region, and to ensure resource adequacy as required by the Florida Public Service Commission and compliance with FRCC Standards and North American Electric Reliability Corporation (NERC) Reliability Standards. NERC is the Electric Reliability Organization of the United States.

As part of this annual assessment, the FRCC aggregates forecasted load and resource data reflecting expected conditions over the next ten years. The FRCC receives data from its members to develop the resulting Regional Load & Resource Plan (RLRP). Based on the information contained in the RLRP, a Reliability Assessment Report is developed and submitted to the Florida Public Service Commission (FPSC) along with the RLRP.

The majority of proposed new generators within the FRCC Region are expected to use natural gas as their primary fuel. Currently, generators using natural gas as a primary fuel provide approximately 58% of the energy (GWh) in the FRCC Region. However, that projection is expected to peak at just over 61% in 2012, and then level off at 58% by 2021.

With no native gas reserves or supplies, two major pipelines deliver more than 90% of the natural gas to peninsular Florida. These pipelines are currently sufficient, when fully operational, to meet the natural gas demands in the Region. However, projected increases in dependence on natural gas for generating capacity, could create potential reliability issues should (a) demand continue to grow such that capacities of these systems are exceeded; (b) or, in the event of a long term interruption to existing natural gas delivery infrastructure. The FRCC continues coordination efforts among natural gas transporters and generators within the Region. The *FRCC Generating Capacity Shortage Plan*[1] 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*[2], provides 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 and near-term fuel supply infrastructure in terms of reliability for generating capacity.

In summary, the findings of the 2012 Reliability Assessment of the FRCC Region are:

- Reserve margins for the FRCC Region for the summer and winter peak hours exceed 20% for each year in the ten-year period, well above the FRCC's minimum Reserve Margin Planning Criterion of 15%;
- Overall Regional Availability of generation in the first three years is somewhat lower than last year's forecast due to projections of longer planned outage plans for generating units; however, projected availability values return to levels consistent with projections made in previous years for the remainder of the 10-year analysis period;

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

[2] FRCC Handbook – FRCC Communications Protocols -Reliability Coordinator, Generator Operators, and Natural Gas Transportation Service Providers (https://www.frcc.com/handbook/Shared Documents/EOP - Emergency Preparedness and Operations/FRCC Communications Protocols 102207.pdf) developed in response to FERC Order 698.

- Likewise, projected forced outage rates for the first three years are somewhat higher than last year's forecast, largely due to the extended forced outage of one large generating unit; however, the projected forced outage rate values return to levels consistent with projections made in previous years for the remainder of the 10-year analysis period;
- Therefore, due to projected high Reserve Margins, previous projections of very low loss-of-load-probability (LOLP) values, supplemented with projected low forced outage rates and high availability values 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;
- Reliability analysis of new considerations, such as the degree to which the peninsular Florida system is becoming increasingly dependent upon demand side management (DSM) to meet its Reserve Margin criterion, have begun in order to ensure that the peninsular Florida system remains reliable in the future;
- The natural gas pipeline capability is currently adequate; however, with limited infrastructure diversity and increasing dependence, adequacy could be impacted by the potential that future demand growth could exceed capacities or in the event of longer term pipeline outages or failures.
- New planned nuclear capacity is expected to increase by almost 600 MW through the uprates of existing units, and approximately another 1,100 MW from new construction;
- The load forecast is reasonable and sound. The 2012 load forecast reflects a lower load growth than reflected in prior years' load forecasts.

FRCC Reserve Margin Review

The FRCC has a resource criterion of a 15% minimum Regional 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 summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC[3]. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion.

For any forecasted peak period that the Regional Reserve Margin requirement is not met, this will be researched and reflected in the annual Load & Resource Reliability Assessment Report.

[3] 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)

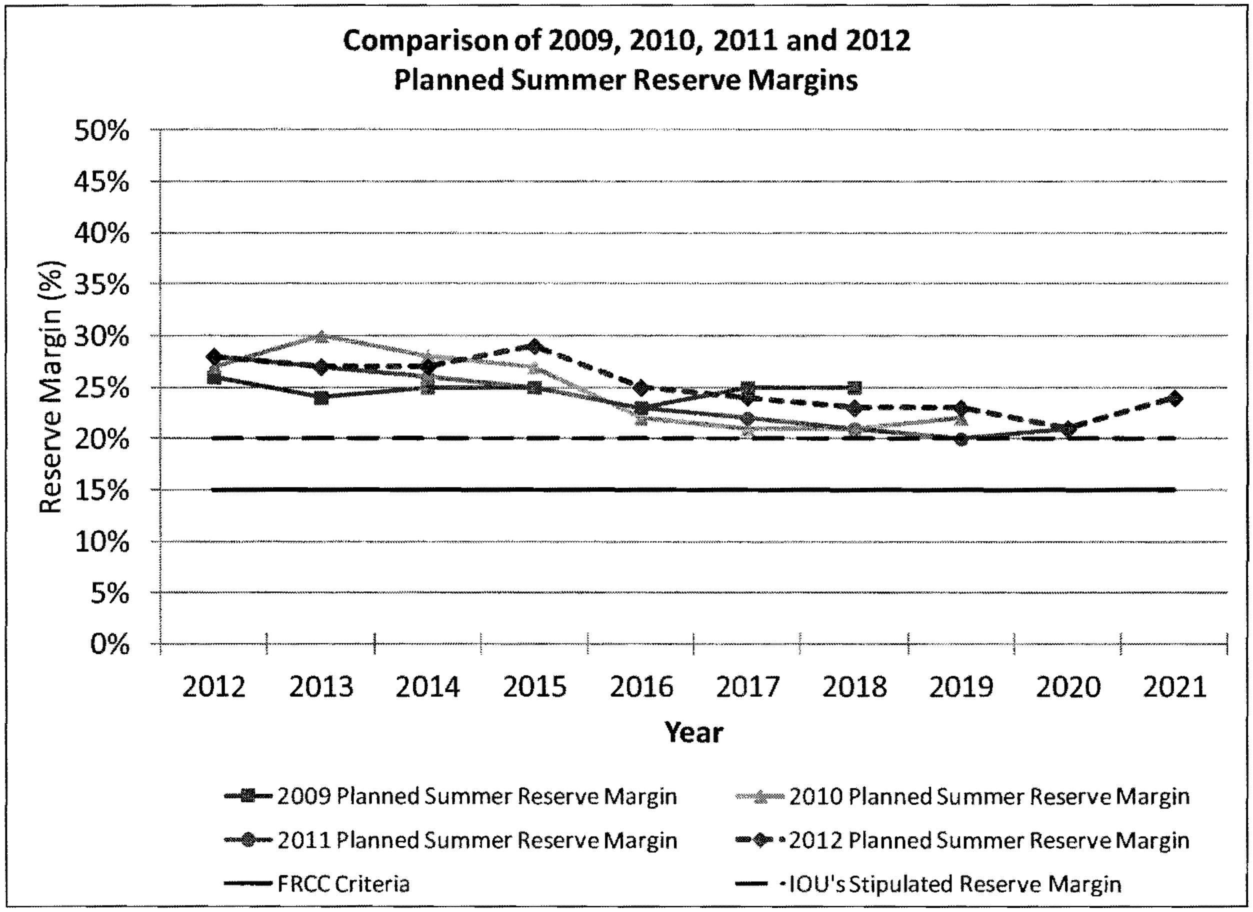

Figure 1

Figure 1 shows that the summer Reserve Margins from the 2012 *Regional Load & Resource Plan*[4] continue to be above the FRCC's minimum Reserve Margin requirement. The projected summer Reserve Margins exceed 20% for every year in the ten-year forecast period. A primary driver of the higher summer Reserve Margins is the significant reduction of the future peak demand now forecasted by Florida utilities. Other contributing factors are increases in Demand Side Management programs, generating resources, and unit repowerings.

[4] 2012 Regional Load & Resource Plan (https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202012%20Load%20and%20Resource%20Plan.pdf)

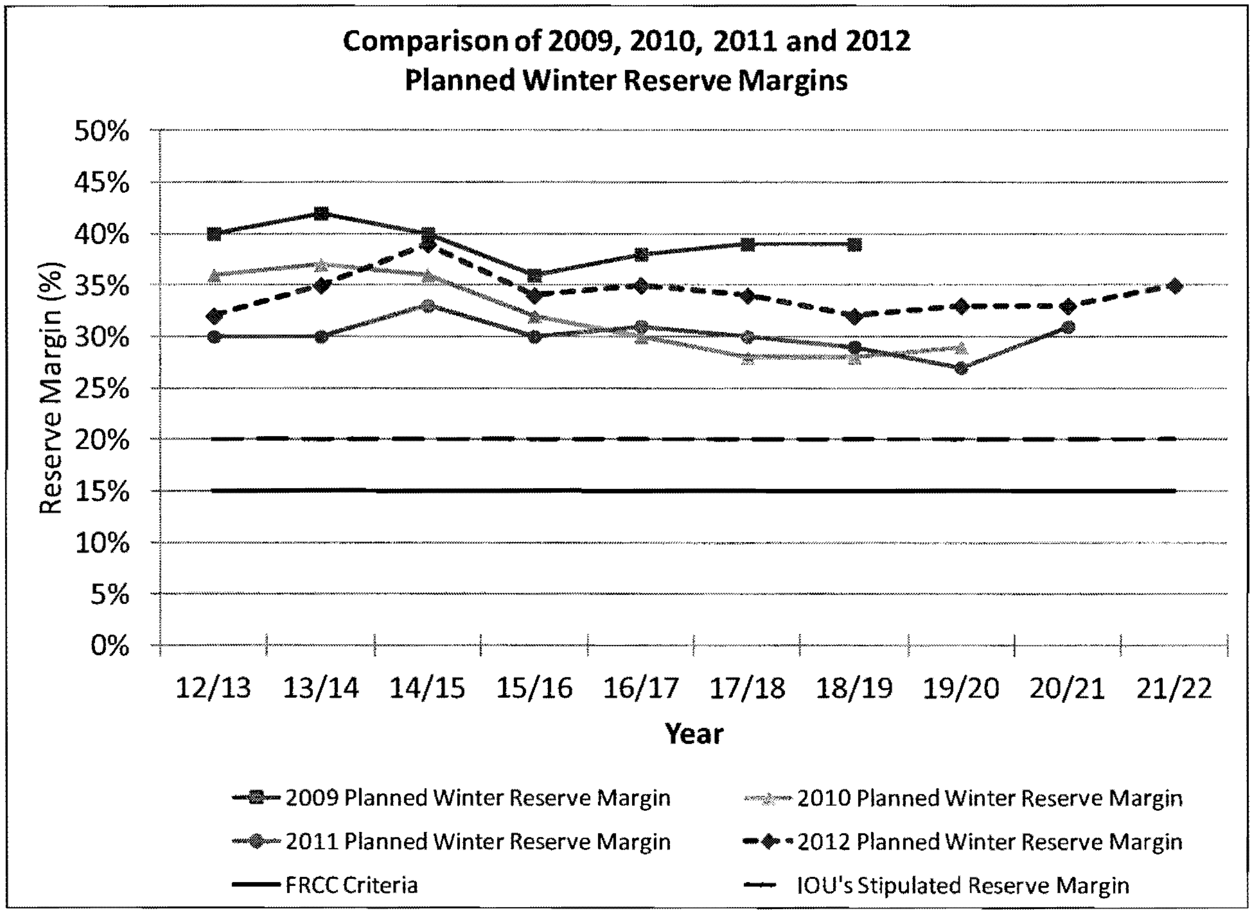

Figure 2

In a similar manner, ***Figure 2*** above shows the winter Reserve Margins from the 2012 *Regional Load & Resource Plan*[4] above. The winter Reserve Margins are also over 20% for every year in the ten-year forecast period.

FRCC Resource Adequacy Criteria Review

Introduction

Periodic reviews of projected Loss of Load Probability (LOLP) every 3 – 5 years, along with annual reviews of projected generator Forced Outage Rates (FOR) and Availability Factors (AF), are performed in addition to the Reserve Margin Review to determine if the planned resources for the FRCC Region will meet FRCC, FPSC, and NERC requirements for resource adequacy. In addition, other considerations that can affect system reliability are also examined.

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 serve 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 order to maintain the resource level that satisfies this criterion, the FRCC established a Regional Reserve Margin Planning Criterion (also known as a Resource Adequacy Criteria) of a minimum 15% Reserve Margin for both Summer and Winter versus firm load.

The latest LOLP analysis was conducted in 2009 and it examined projected LOLP values under "most likely" conditions, and under a variety of extreme scenarios including: no availability of firm imports, no availability of Demand Response, and a 5% increase in peak loads. The results of the 2009 LOLP analysis show that the peninsular Florida electric system was again projected to maintain an LOLP level well below the LOLP criterion for the ten year study horizon for the scenarios considered in the analysis. Based on these results, the Resource Working Group (RWG) recommended that the Reserve Margin Planning Criteria be maintained.

The 2009 LOLP analysis indicated that the reference case for the peninsular Florida electric system does not exceed the planning LOLP criterion of 0.1 days per year for the planning period, as shown in ***Table 1***. The FRCC has also determined, through the evaluation of current forced outage rate and availability factor projections (as discussed below), that these 2009 LOLP values remain representative of an LOLP perspective of peninsular Florida in 2012; i.e., the peninsular Florida system is projected to be reliable from an LOLP perspective.

	BASECASE	5% LOAD SENSITIVITY
Year	LOLP (Days/Year)	LOLP (Days/Year)
2009	0.000000	0.000141
2010	0.000003	0.000824
2011	0.000000	0.000071
2012	0.000000	0.000056
2013	0.000000	0.000043
2014	0.000000	0.000079
2015	0.000000	0.000164
2016	0.000000	0.000070
2017	0.000000	0.000000
2018	0.000000	0.000000

Table 1

2009 LOLP Results

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

Generating unit reliability is a primary driver of LOLP results. For several years the RWG has tracked and monitored two unit performance measures for individual utility systems and the FRCC Region as a whole. This assessment was again conducted as part of the 2012 Reliability Assessment. The measures are the capacity-weighted Forced Outage Rate (FOR) and the capacity-weighted Availability Factor (AF) for each utility system. The individual utility system information is combined to develop FRCC Regional values for FOR and AF. Actual and forecasted FOR and AF values are then trended and compared to historic values. Demonstration of individual utility and Regional stability and/or improvement in these performance measures is an implicit indicator that the LOLP criterion is not being approached.

In the current analysis, both yearly capacity-weighted FOR and AF projected values for each utility system were again calculated. The calculations were based on each utility's latest planning assumptions (i.e., assumptions developed and used in the utility's 2011 resource planning work and which is subsequently reported in the utility's 2012 Ten Year Site Plan (TYSP) and used in the *2012 Reliability Assessment*). These 2011 projected FOR and AF values for the next 10 years were compared to the values projected for previous years' analyses conducted using 2008, 2009, and 2010 planning studies.

As seen in ***Figure 3,*** the 2011 projections of FOR remain generally in-line with projections made using data from 2008 through 2010. The 2011 projections do show a projected increase in FOR for the years 2012, 2013, and 2014. The primary driver of this projected increase is the extended forced outage of one single large unit. However, starting in 2015, the general trend in the forecasted FOR rates is flat over time, and in a relatively narrow range, consistent with earlier projections, indicating that the peninsular Florida system is projected to remain resource adequate and maintain its reliability from 2015 through 2021. In regard to the years 2012 through 2014, the fact that the relatively small increase in projected FOR is largely driven by the status of only one generating unit, coupled with the very low projected LOLP values for all years from the 2009 LOLP analysis, and a projected Reserve Margin for all years in excess of the FRCC's 15% Reserve Margin Planning Criterion, indicates that the system is projected to remain reliable during this 3-year period as well. Consequently, these results lead to the conclusion that peninsular Florida system is projected to continue to be reliable throughout the 10-year period analyzed in this document.

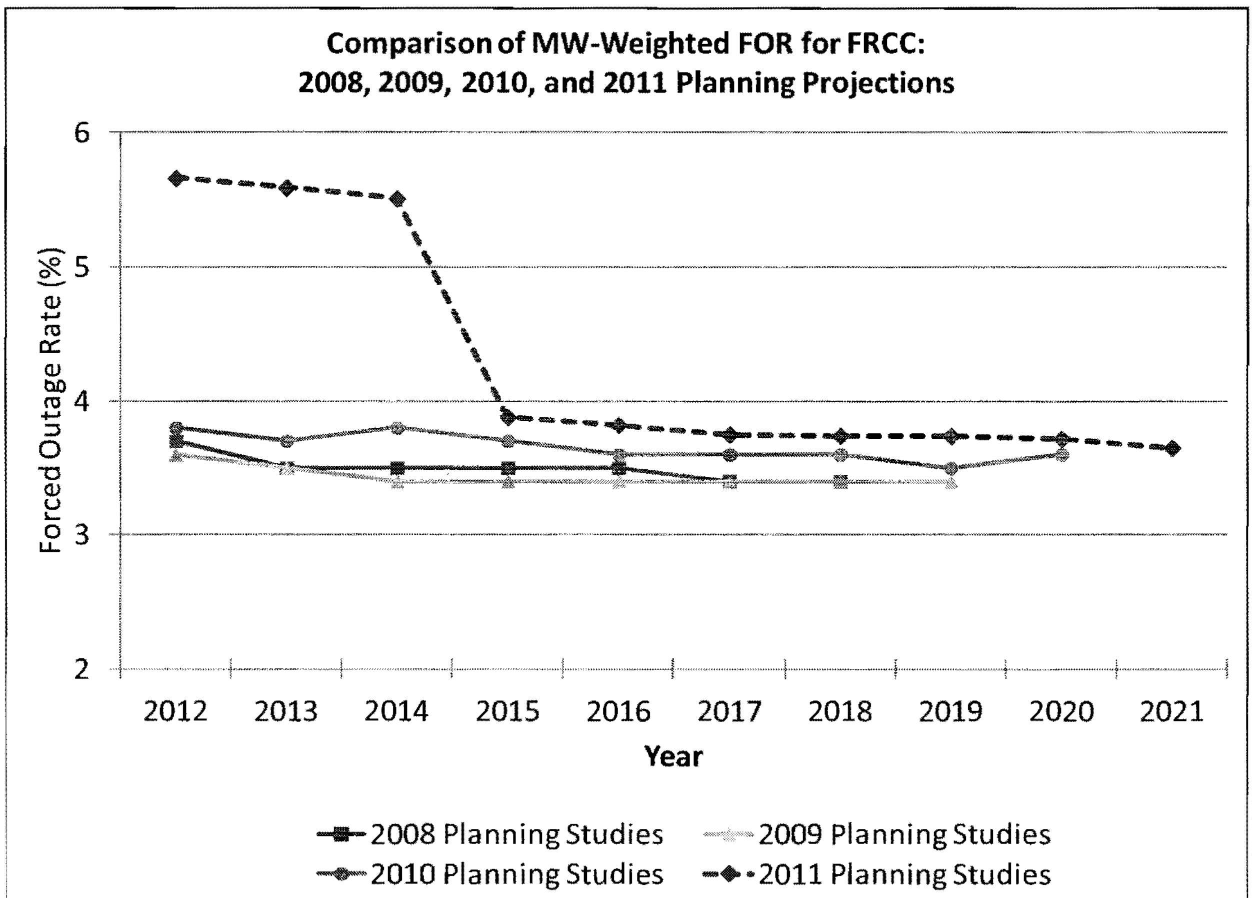

Figure 3

Trends in Forced Outage Rate (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*** shows that 2011 projections of MW-weighted Availability Factor, compared to prior projections, are somewhat lower throughout the 10-year period due, in part, to projections of longer planned outage periods for generating units. The annual differences are relatively small for the years 2015 through 2021. As with the projected FOR values, the primary driver of the larger differences in projected availability for the years 2012 through 2014 is the outage of one large unit on the system. The results of the availability analyses, combined with the results of the FOR analyses depicted in ***Figure 3,*** the very low projected LOLP results for all years from the 2009 LOLP analysis, projected Reserve Margins for all years above the FRCC's Reserve Margin Planning Criterion of 15%, and the fact that the relatively small decrease in projected availability for the first 3 years is largely driven by the status of only one generating unit, supports the previous conclusion that peninsular Florida system is projected to continue to be reliable throughout the 10-year period analyzed in this document.

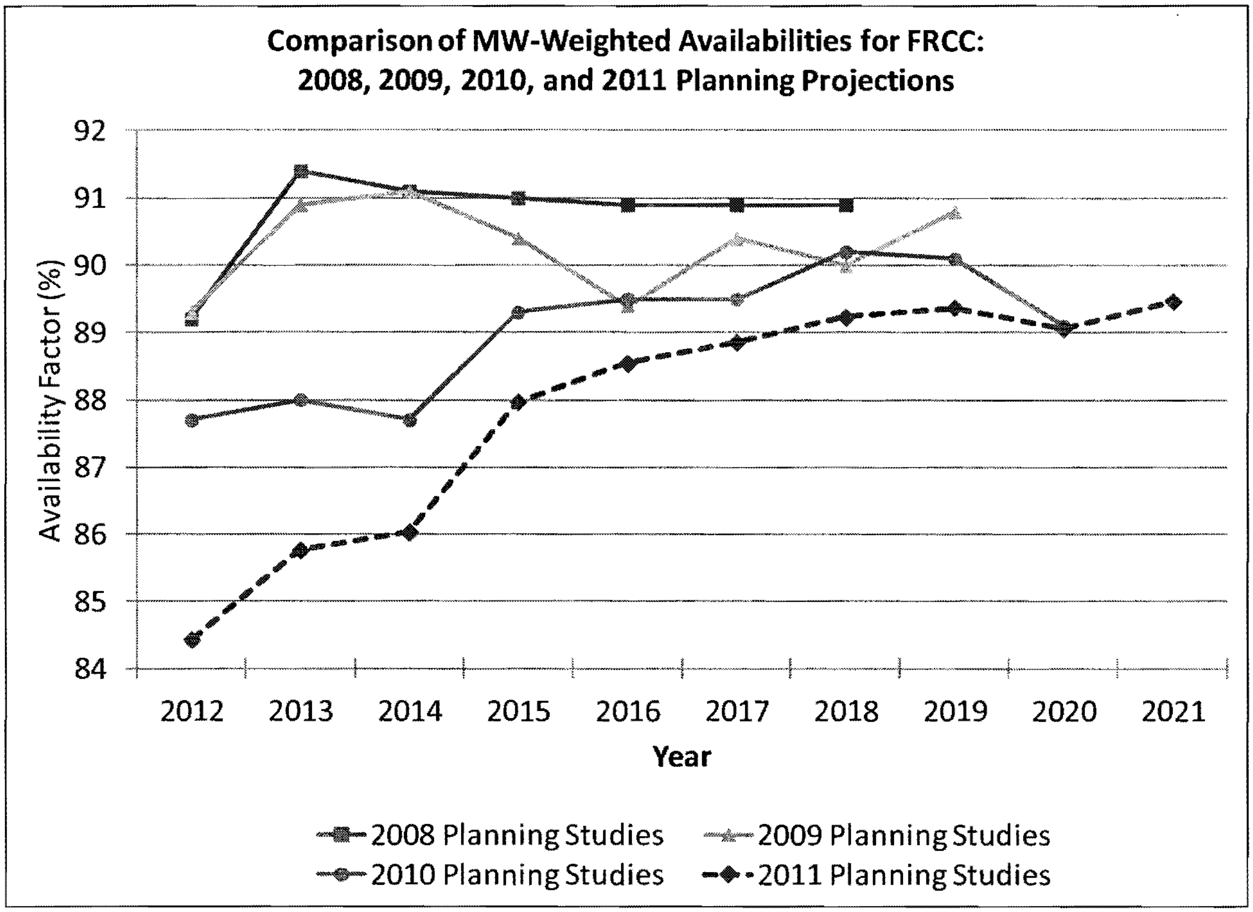

Figure 4

Trends in Availability Factor (AF)

Resource Adequacy Review Process

A brief summary of the resource adequacy review process follows:

1. <u>Review of statistics currently used for tracking system performance</u>

   As previously presented, the FRCC RWG performs periodic LOLP studies and annual reviews of system-wide FOR and AF as indicators of resource adequacy. The FRCC RWG previously assessed the option of using modified indices in place of FOR and AF as reliability indicators, but determined that such indices would not provide new information. Present indices are still 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. As RWG has previously concluded, it is still appropriate to continue the use of FOR and AF as reliability measures in place of performing an LOLP analyses each year. Efforts are underway at NERC to calculate Regional probabilistic performance indices for EUE (Expected Unused Energy) and LOLH (Loss of Load Hours) which are planned in support of future FRCC analyses and studies.

2. <u>Examination of potential new statistics for evaluating system reliability</u>

   In its 2012 work, the FRCC began to examine an additional aspect of the peninsular system that could have implications for the future reliability of the system. This aspect is the extent to which the system's projected Reserve Margin values rely upon demand side management (DSM) to meet and maintain the FRCC's 15% Reserve Margin Planning Criterion. In order to examine the extent to which the peninsular 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 developed based on aggregating utilities' 2012 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***, shows peninsular Florida's projected future Reserve Margins when considering only generating unit contributions. In addition, the projected generation-only reserve margin for Florida Power & Light is also presented.

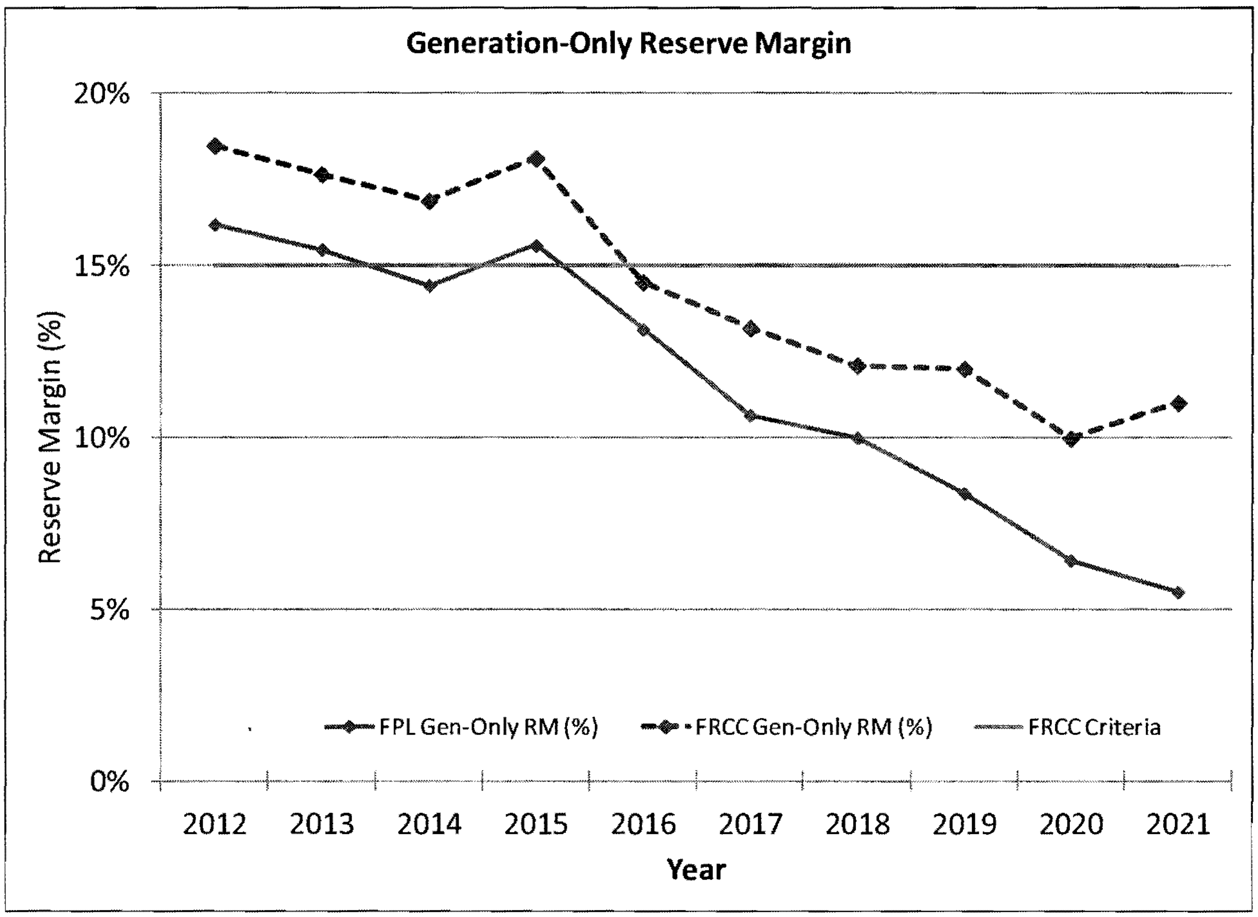

Figure 5

Generation-Only Reserve Margin

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[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 additions.

As shown in ***Figure 5***, peninsular Florida is projected to become increasingly dependent upon DSM, and less reliant upon generation resources, over the 10-year planning horizon. Although projections for several individual utilities show a general trend of decreasing generation-only Reserve Margins over this 10-year period, the biggest contributor to the projected decrease in generation-only Reserve Margin for the peninsula is FPL. As shown in ***Figure 5***, FPL's generation-only Reserve Margin is projected to decrease from 16.2% in 2012 to 5.5% by 2021, even while FPL maintains an overall Reserve Margin above 20%. And because the FPL system constitutes approximately 50% of the peninsula's projected capacity and load, the projected decrease in FPL's generation-only Reserve Margin has a very significant effect on the projected generation-only Reserve Margin of peninsular Florida.

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

3. Fuel Deliverability

The dependency on natural gas (NG) and possible NG fuel supply or delivery disruptions may impact the long term adequacy of FRCC resources to meet customer load and thus should be 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 gas study indicated minimal risk to the reliability of the power system within the FRCC Region related to shorter term gas delivery disruptions.

Peninsular Florida is becoming increasingly dependent on natural gas as a source of fuel for electric generation. This trend is expected to continue over the coming years as utilities continue to install natural gas fired generation to meet new load, as well as replace existing generating facilities with more efficient natural gas burning generation. Approximately 58% of Florida's delivered electricity is powered by natural gas. However, the state has no native gas reserves and relies 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 state. These two pipelines currently have the ability to deliver almost 4.4 billion cubic feet per day ("Bcf/day"). (FGT at just under 3.1 Bcf/day and Gulfstream at just over 1.3 Bcf/day) to markets in the state of Florida where more than 80 percent of this natural gas supply 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 MMcf/day into Florida; however, 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 must flow through FGT to reach end use markets and, as such, the majority of this capacity is not additive to FGT delivery capacity. As to future requirements, these existing natural gas pipelines into Florida are almost fully subscribed, though Florida's natural gas needs are expected to increase in the coming years. To meet the anticipated growth in demand, the gas transportation infrastructure serving the state will also need to expand. As the state relies on primarily two pipeline service providers sourcing natural gas supplies from primarily Gulf Coast supply sources, Florida could benefit from projects that increase supply flexibility, delivery diversity and increased interconnections. Additionally, a long term interruption of either of the two primary pipelines into the state could significantly impact the adequacy of resources within the FRCC to serve customer load during the period required to repair the pipeline. Increasing pipeline diversity ultimately decreases vulnerability to unplanned outages of any gas delivery infrastructure. In order to ensure the reliability of Florida's natural gas supply, utilities have added additional "upstream pipeline transportation capacity" to access onshore shale gas reserves. 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 are tempered by the limited access provided by the current pipeline delivery infrastructure.

4. Transmission Capability

The FRCC 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.

5. Environmental Compliance

The FRCC RWG concludes that current environmental requirements imposed by federal, state, and local authorities that may impact the capacity and operation of generation resources are adequately accounted for within the resource adequacy process through the individual utility resource planning processes. Any 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 utility-specific resource planning process.

There continues to be discussion at the State and Federal level with regards to renewable energy and climate change that may have an impact on the type of future generating resources that will need to be added to meet potential mandates. However, 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. Although renewable energy sources applicable in Florida can address an energy-only mandate, most of these renewable sources, with the exception of biomass, would not significantly contribute to providing firm capacity that will be needed to meet the Region's growing load and to maintain system reliability. (However, any additional nuclear capacity would provide clean energy while also providing firm capacity.) In addition, potential changes in federal laws and regulations that pertain to environmental compliance and/or type of electrical generating units will be closely monitored by the FRCC and member entities.

Future Work on Resource Adequacy

The LOLP process uses probabilistic analysis to quantify the ability of the generation system resources to reliably meet expected demand, incorporating the uncertainties associated with generation reliability including unit outage rates, maintenance schedules, load uncertainty, and Demand Response. It should 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 the 2009 LOLP analyses, and recognized areas that can be addressed to add more depth and detail to the resource adequacy analysis.

FRCC will continue to conduct various studies to ensure Regional resource adequacy. The Resource Working Group plans to address the following:

1. <u>LOLP/LOLE Analysis</u>

   - <u>Load Forecast Uncertainty</u>

     The current modeling approach assumes the most likely load forecast prevails (with the exception of extreme summer and winter sensitivities). In addition, a sensitivity analysis was performed assessing a 5% increase over the forecasted peak load 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.

   - <u>Major Maintenance Schedule Variation</u>

     The current modeling approach uses automatic maintenance schedules projected by member entities for their units. Any deviations from planned schedules may impact the projected LOLP/LOLE values.

2. Analysis of Growing Dependency on DSM to Maintain System Reliability

As previously discussed, the RWG has begun to examine the extent to which peninsular Florida is projected to be dependent upon DSM to maintain system reliability and the implications of that higher degree of dependence. This issue will continue to be examined by the RWG, and by individual utilities, in subsequent years.

3. Transmission Constraints

The current modeling approach assumes that sufficient transfer capability exists between all utility systems within the FRCC Region and SERC (with the exception of sensitivities where SERC transfer is explicitly limited or precluded). The current modeling approach also 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. The RWG, in conjunction with TWG, will review this assumption and develop a plan for addressing transmission constraints in future resource adequacy reviews.

FRCC Load Forecast Evaluation

The current demand for electricity by peninsular Florida consumers declined in 2011 and is reflected in the current forecasts of customers, demand and energy consumption. In the later part of 2010 customer growth turned positive for the first time in over a year. In 2011, average customer growth was 0.5%, slightly lower than the projected 1.0% growth. While customer growth is improving in the state, average per-customer consumption in all classes continued to decline through 2011. The extreme weather conditions in 2010 made it difficult to establish an ongoing trend in energy consumption, and what seemed to be a slight rebound in 2010 turned out to be a continued decline in average consumption which continued into 2011. As the economy began to build some momentum in 2010, economic projections at that time continued that momentum into 2011 and accelerate further in 2013 and beyond. In reality, 2011 did not have the level of economic growth that was projected and more recent economic projections forecast a somewhat slower recovery in Florida.

The 2012 Regional customer forecast is lower than the 2011 forecast primarily due to lower population projections. Although customer counts are lower, the projected ten year average annual growth rate of 1.3% is still in line with prior projections. On a per-customer basis, consumption projections are approximately 2% lower in the short-run with less of a decline thereafter. Residential consumption will remain relatively flat during the forecast horizon, growing at an average annual rate of 0.4%. The combined reduction in the growth of residential customers and per-customer consumption results in an energy sales growth forecast that is 3.6% lower than the prior projections. The residential class is the primary driver of the reduction in the growth of total energy sales and net energy for load. Commercial energy sales remain relatively equal to last year's projections, while all other classes have lower energy sales projections compared to last year. Any increases in consumers' demand for electricity is offset by efficiency gains from new appliance standards as well as mandated and voluntary conservations efforts.

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. Whereas, some utilities have attempted to incorporate these impacts in the load forecast, a number of utilities capture embedded efficiency trends that have been taking place historically through their econometric models as well as through utility-sponsored DSM program savings.

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 since it is only logical to assume that each utility is most familiar with its own service territory. The load forecast evaluation process undertaken by FRCC is to ensure that each utility in preparing this outlook is availing itself of the best available information in terms of data, forecasting models and to a certain degree consistency of assumptions across all utilities. FRCC's Load Forecasting Working Group (LFWG) reviewed in detail each utility's forecast

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)

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 imbedded in the primary factors that determine the demand for electricity. The uncertainties that are most noticeable are departures from historical weather patterns, recent population growth, performance of the local and national economy, size of homes and number of homes being built, inflation, interest rates, price of electricity, changing electric end use technology, appliance efficiency standards and changes in consumption patterns. In the short-run, weather deviations from the normal are most important but population growth, economic performance, price of electricity, changing technology, changing consumption patterns and efficiency standards 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 level 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:

A. Models

Review and technically assess 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 the utilities in the state of Florida. However, there were some utilities that found 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.

B. 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 from *Moody's Economy.com*[9], all reputable forecasting firms. The price of electricity was derived internally by each utility and consisted of base rates and all "pass-through" clauses filed with the FPSC. The National Oceanographic and Atmospheric Administration (NOAA) provided all historical weather used in model estimation and calibration. Given that 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 specific distinctiveness. As such, some utilities employed the average weather over the last 20 years, others the last 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

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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)

such as *Global Insight*[10] and *Moody's Economy.com*[9]. The utilities across the State are nearly divided evenly among those using *Global Insight* and those using *Moody's Economy.com.* Both 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.

C. Outputs

To assess the quality of the load forecasts two measures were employed. The current forecast was compared (1) to the prior forecast developed last year and (2) to the recent historical past. The 2012 Regional load forecast is lower than the 2011 forecast primarily due to a less robust economic recovery. Lower population projections and lower growth in economic drivers such as household income and GDP resulted in a lower number of customers and lower average consumption levels.

The projected average annual growth rate for customers over the long-term planning horizon is 1.3%, compared to 1.4% in the previous forecast. Growth in Net Energy for Load ("NEL") and peak demand are also forecasted to decrease over the long-term planning horizon. In addition to the downward shift in NEL and peak demands, there is also a slowdown in the average annual growth rate in the planning horizon. Firm summer peak demand is expected to grow by 1.4% per year versus 1.5% per year in the previous forecast. For firm winter peak demand, the ten-year average annual growth rate is now expected to be 1.1% compared to 1.3% in the previous forecast. The average growth rate for NEL of approximately 1.6% per year is in line with the previous forecast.

[10] Global Insight (http://www.globalinsight.com)

D. 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 with 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 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 2011 and 2012 forecasts is that the latter forecast projects lower average consumption for all customer classes and lower residential customer growth than the former forecast. The residential class is the primary driver of the lower energy sales and NEL projections. The comparison between the 2011 and 2012 forecasts for summer and winter peaks are shown in ***Table 2.***

Florida Reliability Coordinating Council
Comparison of 2011 and 2012 Forecasts

Summer Peak					Winter Peak				
	Forecast		Difference			Forecast		Difference	
Year	2011	2012	MW	%	Year	2011	2012	MW	%
2012	46,658	45,613	-1,045	-2.2%	2012 / 13	48,276	46,864	-1,412	-2.9%
2013	47,446	46,270	-1,176	-2.5%	2013 / 14	48,889	46,367	-2,522	-5.2%
2014	48,228	46,857	-1,371	-2.8%	2014 / 15	49,534	47,568	-1,966	-4.0%
2015	49,278	47,758	-1,520	-3.1%	2015 / 16	50,148	48,172	-1,976	-3.9%
2016	50,036	48,594	-1,442	-2.9%	2016 / 17	50,812	48,797	-2,015	-4.0%
2017	50,833	49,244	-1,589	-3.1%	2017 / 18	51,408	49,298	-2,110	-4.1%
2018	51,377	49,643	-1,734	-3.4%	2018 / 19	52,088	49,908	-2,180	-4.2%
2019	52,186	50,356	-1,830	-3.5%	2019 / 20	52,784	50,570	-2,214	-4.2%
2020	53,083	51,191	-1,892	-3.6%	2020 / 21	53,415	51,218	-2,197	-4.1%

Values are non-coincident peaks

Table 2

With regard to the 2012/13 winter peak, the 2012 forecast is lower than the 2011 forecast by approximately 2.9%. This is the result of the calibration of the peak winter demand and the projections of a less robust economic recovery. The 2011/12 winter peak was 39,924 MW and was 7,689 MW (16%) 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 1.1% per year, compared to 1.3% in the prior forecast.

The actual 2011 summer peak was 2.8% (1,293 MW) lower than projected, primarily due to weather conditions. The 2012 projections for summer peak demand show a decrease in 2012 of 2.2%, (1,045 MW) and decreasing by 3.6% (1,892 MW) by the end of the forecast horizon compared to the 2011 forecast. Over the last ten years peninsular Florida has averaged approximately 1.3% of growth in summer peak per year. The current ten-year projection has this growth at 1.5% 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, 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 PRIOR SUMMER PEAK FORECASTS
(MW)

Year	Actual Summer Peak (MW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2002	39,903	40,145									
2003	40,417	41,335	41,618								
2004	42,172	42,292	42,668	42,705							
2005	45,924	43,279	43,670	43,753	43,495						
2006	45,344	44,274	44,727	44,826	44,680	45,520					
2007	46,525	45,168	45,795	45,896	45,962	46,725	46,878				
2008	44,706	46,107	46,840	46,897	47,108	48,030	48,037	47,364			
2009	46,263	47,064	47,898	47,990	48,344	49,233	49,280	48,181	45,734		
2010	45,564	48,095	49,008	49,146	49,556	50,221	50,249	49,093	45,794	46,006	
2011	44,798	49,151	50,164	50,297	50,796	51,343	51,407	50,284	46,410	46,124	46,091

FORECAST VARIANCE
(PERCENT)

Year	Actual Summer Peak (MW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2002	39,903	-0.6%									
2003	40,417	-2.2%	-2.9%								
2004	42,172	-0.3%	-1.2%	-1.2%							
2005	45,924	6.1%	5.2%	5.0%	5.6%						
2006	45,344	2.4%	1.4%	1.2%	1.5%	-0.4%					
2007	46,525	3.0%	1.6%	1.4%	1.2%	-0.4%	-0.8%				
2008	44,706	-3.0%	-4.6%	-4.7%	-5.1%	-6.9%	-6.9%	-5.6%			
2009	46,263	-1.7%	-3.4%	-3.6%	-4.3%	-6.0%	-6.1%	-4.0%	1.2%		
2010	45,564	-5.3%	-7.0%	-7.3%	-8.1%	-9.3%	-9.3%	-7.2%	-0.5%	-1.0%	
2011	44,798	-8.9%	-10.7%	-10.9%	-11.8%	-12.7%	-12.9%	-10.9%	-3.5%	-2.9%	-2.8%

Actual values are non-coincident peaks

Table 3

The first column in ***Table 3***, labeled "Actual Summer Peak (MW)", corresponds to the actual observed 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 2002 through 2011. 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 for the table shown in ***Table 3*** provides additional information. For example, beginning in 2002 up to 2004, the summer forecast variances have been low indicating remarkable accuracy for the first few years of the forecast period. The year 2005 is an outlier and reflects the effects of the "abnormal" weather in this year.

By 2006 and 2007, actual summer peaks variances for projections made in 2002 get quite high. 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. In 2006 and 2007, the FRCC forecasts missed its target 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 2006 or 2007. Although FRCC members predicted a slowdown in 2008, the extent of the downturn was more severe than expected. The 2008 summer peak variance was -5.6% and as low as -6.9% in 2006 and 2007 projections. The 2010 summer peak variance versus the 2010 forecast was -1.0% compared to -0.5% versus the 2009 prior forecast. This smaller forecast variances in 2009 and 2010 were due to the recalibration of the forecasting models to reflect the economic downturn.

An unpredictable downturn is also evident 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 were significantly lower, resulting in a summer peak load variance of -2.8% compared to the 2011 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, especially when ensuring system reliability and required Reserve Margins. The FRCC forecast does not attempt to capture these short-term deviations but to portray the most likely outcome in terms of projected load for the state of Florida over the next ten years.

COMPARISON OF PRIOR WINTER PEAK FORECASTS
(MW)

Year	Actual Winter Peak (MW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2002 / 03	44,472	43,199									
2003 / 04	35,564	44,219	44,266								
2004 / 05	41,090	45,237	45,301	45,418							
2005 / 06	43,202	46,242	46,419	46,546	46,717						
2006 / 07	38,023	47,215	47,561	47,692	47,994	48,296					
2007 / 08	41,495	48,208	48,682	48,769	49,139	49,464	49,526				
2008 / 09	45,590	49,298	49,814	49,944	50,414	50,732	50,737	49,601			
2009 / 10	51,767	50,331	50,945	51,122	51,700	51,678	51,673	50,463	44,446		
2010 / 11	45,876	51,439	52,166	52,357	53,030	52,869	52,780	51,606	45,099	46,235	
2011 / 12	39,924	52,537	53,422	53,598	54,370	53,923	53,872	52,753	46,140	46,821	47,613

FORECAST VARIANCE
(PERCENT)

Year	Actual Winter Peak (MW)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2002 / 03	44,472	2.9%									
2003 / 04	35,564	-19.6%	-19.7%								
2004 / 05	41,090	-9.2%	-9.3%	-9.5%							
2005 / 06	43,202	-6.6%	-6.9%	-7.2%	-7.5%						
2006 / 07	38,023	-19.5%	-20.1%	-20.3%	-20.8%	-21.3%					
2007 / 08	41,495	-13.9%	-14.8%	-14.9%	-15.6%	-16.1%	-16.2%				
2008 / 09	45,590	-7.5%	-8.5%	-8.7%	-9.6%	-10.1%	-10.1%	-8.1%			
2009 / 10	51,767	2.9%	1.6%	1.3%	0.1%	0.2%	0.2%	2.6%	16.5%		
2010 / 11	45,876	-10.8%	-12.1%	-12.4%	-13.5%	-13.2%	-13.1%	-11.1%	1.7%	-0.8%	
2011 / 12	39,924	-24.0%	-25.3%	-25.5%	-26.6%	-26.0%	-25.9%	-24.3%	-13.5%	-14.7%	-16.1%

Actual values are non-coincident peaks

Table 4

The analysis for winter peaks is shown on ***Table 4.*** A perfunctory review 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 peaks of 2003 and 2004. The year 2003 had a cold winter and the total demand of electricity reached a record of 44,472 MW of peak winter demand. Conversely, the year 2004 was very mild and the peak demand reached only 35,564 MW, a drop of 8,908 MW in peak demand between successive years. In 2010, the winter peak load was 51,703 MW which was 7,257 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 experienced in very 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 2009/2010 turned out to be the coldest winter on record (or very close) in many areas of peninsular Florida. All existing load control programs served their designed purpose and firm load was served throughout the peak load period. The 2011/12 winter peak was 16.1% below forecast due to very mild weather during the winter months.

Finally, ***Table 5*** shows a comparison between the historical load factors (for 2002 through 2011) and the projected load factors based on the summer peak. The summer peak was chosen because it is less volatile than the winter peak, which fluctuates widely over the historical years since cold winters have occurred only sporadically. Both historical and forecasted load factors are similar in magnitude. This provides comfort in knowing that both the average loads and peak loads are growing at a comparable rate.

FRCC LOAD FACTORS
Based on Summer Peak

Year	Load Factor
2002	0.603
2003	0.620
2004	0.595
2005	0.563
2006	0.579
2007	0.571
2008	0.579
2009	0.558
2010	0.584
2011	0.571
2012	0.561
2013	0.560
2014	0.562
2015	0.563
2016	0.562
2017	0.562
2018	0.565
2019	0.565
2020	0.566
2021	0.569

Table 5

As a result of this evaluation, the FRCC LFWG concludes that the load forecast is suitable and reasonable and can be used for reliability assessment purposes.

FRCC Transmission

Currently, there are 46 miles of transmission lines under construction as of 1/1/2012. However, there are 594 miles of planned transmission lines identified throughout the 2012-2021 planning horizon. At this time, it is expected that the target in-service dates of this transmission will be met.

Transmission constraints in the Central Florida area will require remedial actions depending on system conditions creating increased west-to-east flow levels across the Central Florida metropolitan load areas. Permanent solutions such as the addition of new transmission lines and the rebuild of existing 230kV transmission lines are planned to be in-service by 2013. In the interim, remedial operating strategies have been developed to mitigate thermal loadings and will continue to be evaluated to ensure system reliability.

The FRCC Region participants perform various transmission planning studies addressing NERC Reliability Standards TPL-001 – 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 for normal, single and multiple contingency analysis of the FRCC Region 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 and transformer tap adjustments. The majority of planned additions or changes to the FRCC transmission system are related to: planned generation expansion, expected load growth, and relieving transmission constraints (e.g., in the Central Florida area).

In addition, the transmission expansion plans representing the longer-term study are typically under review by most transmission owners still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most transmission owners, these projects are not typically 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.

FRCC Fuel Reliability

Based on past operating experience and analyses with actual hurricane impacts to the fuel supply infrastructure within and outside the Region, the *FRCC Generating Capacity Shortage Plan*[11] was revised to distinguish 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*[12], provides 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.

Currently, the expected percentage of capacity generation (MW) whose primary fuel is natural gas is projected to reach over 59% by 2021. A similar long-term forecast projects coal-fired generation to account for 14% of capacity, nuclear for over 9%, and oil-fired generation for

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

[12] FRCC Handbook – FRCC Communications Protocols -Reliability Coordinator, Generator Operators, and Natural Gas Transportation Service Providers (https://www.frcc.com/handbook/Shared Documents/EOP - Emergency Preparedness and Operations/FRCC Communications Protocols 102207.pdf)

about 13% of generation resources. Less than 5% of capacity generation is from MSW, Inter-Regional interchange, and miscellaneous fuels.

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, from a Regional perspective, to the RC and SCEC. Fuel Data Status reporting is typically performed when threats to Regional fuel availability have been identified and is 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 optimal coordination to minimize impacts of Regional fuel supply issues and/or disruptions on Bulk Electric System facilities and customers.

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 Bulk Electric System reliability during peak periods and/or during extreme weather conditions in the near term.

FRCC Renewables

Nationally, the definition of renewable 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 facilities and some types of hydroelectric and waste heat from cogeneration facilities. The State of Florida has defined the term "Renewable Energy" in Florida Statue 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." Further the term "Biomass" is defined as "combustible residues or gases from forest products manufacturing, agricultural and orchard crops, waste products from livestock and poultry operations and food processing, urban wood waste, municipal solid waste, municipal liquid waste treatment operations, and landfill gas."

Thirty-seven states across the nation have a Renewable Portfolio Standard (RPS) as of May 2012. Although the State of Florida does not have a Renewable Portfolio Standard, a portion of its energy is derived from renewable resources. In 2011, renewable resources made up approximately 1.3 percent of Florida's net energy generation, with a minimal contribution from hydro-electric sources. By comparison, on a national level, a significant portion of renewable energy is provided by hydro-electric sources. Excluding hydro-electric energy, approximately 4.7 percent of the US energy production came from renewable generating resources in 2011.

Florida's renewable electric production is largely derived from biomass and municipal solid waste (MSW), biomass materials such as agricultural waste products and wood residues. The biomass and MSW category combined constitutes 84 percent of the renewable energy. The remaining significant categories are landfill gas at 11 percent, solar at 4 percent, hydro-electric at less than one percent and other renewable resources at 1 percent. [See ***Figure 6*** and ***Figure 7*** for a breakdown of the state's renewable energy generation in 2011 and the nation's renewable energy in 2011.]

In November of 2008 Navigant Consulting, Inc. prepared a Florida Renewable Energy Potential Assessment for the FPSC, Florida's Governor's Energy Office and the Lawrence Berkley National Laboratory which detailed the renewable energy potentials within the state's boundaries. Offshore wind, solar PV and biomass were reported to have the highest potential for sources of renewable energy. The technical potential (i.e., the potential without economic considerations) from the Navigant report for renewable energy generation by 2020 (non-cumulative) in the state of Florida is: solar PV 156,000 GWh, offshore wind 125,230 GWh, and biomass 42,673 GWh.

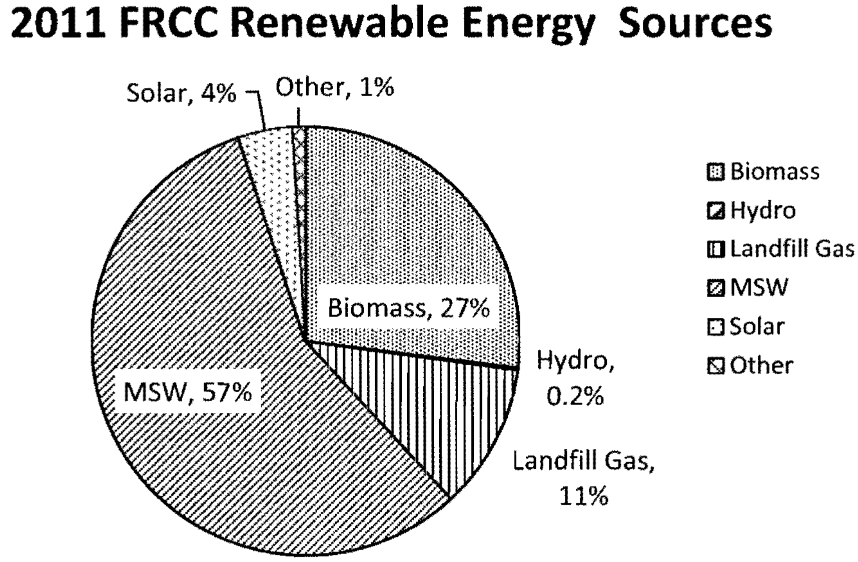

Figure 6

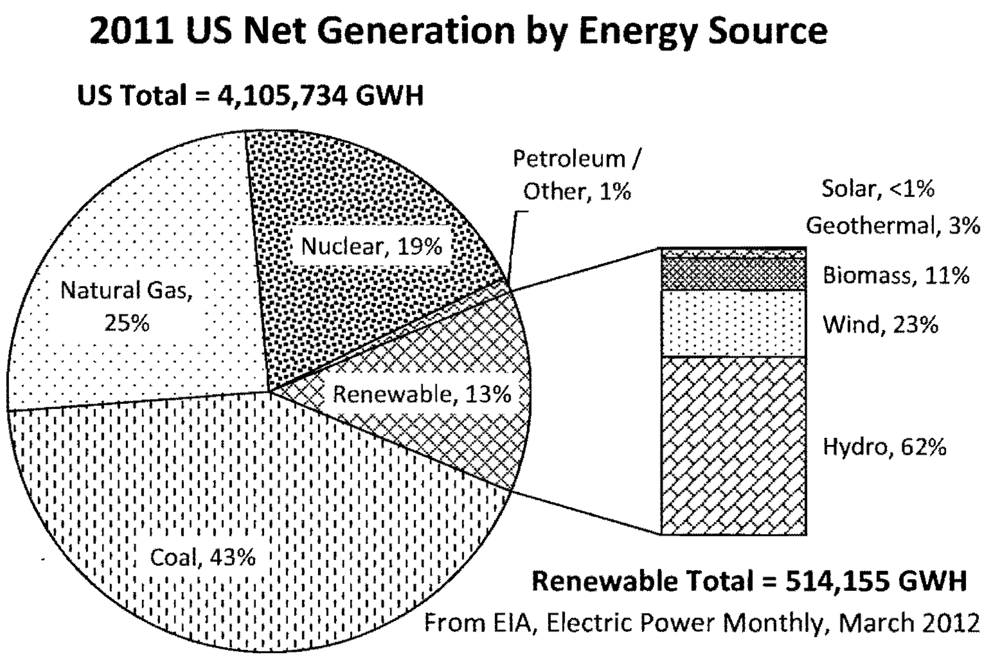

Figure 7

FRCC 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.

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FRCC Long Range Study – Regional Plan (BES)*

2013 – 2022

FRCC
Florida Reliability Coordinating Council, Inc.

	Approval
Prepared by TWG	January 2012
Approved by RE PC	February 29, 2012
Approved by RE BOD	May 4, 2012

* CEII Information Removed

FRCC Bulk Electric System Long Range Study 2013-2022

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FRCC Bulk Electric System Long Range Study 2013-2022

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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 and longer-term steady-state study representing study years 2013 through 2022. This report represents the TWG's compilation and analysis of the Bulk Electric System (BES) performance, with the FRCC Region in accordance with Table 1 of the NERC Reliability Standards TPL-001-0.1, TPL-002-0b and TPL-003-0a. Background information, methodology, analysis, planned projects, and operational workarounds are contained within this report.

This study include 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 BES 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 (2013-2017) and longer-term (2018-2022) planning horizons. All BES transmission facilities, including facilities rated at 69 kV are represented in the FRCC 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 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 of NERC TPL-001-0.1 standard.

The results of single and selected multiple contingency (Category B & C) events identified portions of the BES that require corrective action plans. The corrective action plans ensure the FRCC Region is planned such that the Transmission Network 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-003-0a. Corrective action plans can include new transmission facilities, transmission facility upgrades, Special Protection Systems (SPS) and remedial actions such as generation re-dispatch, line switching, or other operator actions. Together the planned facilities and remedial actions ensure system performance as required by the NERC Reliability Standards TPL-001-0.1, TPL-002-0b & TPL-003-0a.

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 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 BES and its ties with adjacent transmission entities with the assistance of FRCC staff. These assessments, including corrective plans, demonstrate the adequacy of the BES with the FRCC Region.

III. PURPOSE

This document, the FRCC's *2013 – 2022 Bulk Electric System Long Range Transmission Study Report* (STUDY), 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 STUDY communicates the scope, methodology, results, observations and conclusions of the annual study to the FRCC Planning Committee (PC) and other interested parties. 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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[1] Definition of Study – A computer based analysis using the appropriate seasonal base case. System modeling for the base case shall be current, including future planned changes, for each of the base case years

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

IV. SCOPE

Each load flow databank case 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 (2013-2022).[3]

NERC TPL Standards

NERC TPL Standards are used to gauge the adequacy and security of the transmission system. 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 the following Transmission Planning Standards (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-003-0a).

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 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. Separate assessments of the current year winter and summer[4] are performed by the FRCC Operating Reliability Sub-committee (ORS). The longer-term portion examines years six through ten to determine if any trends are developing that would require attention. This is performed to acknowledge the greater confidence in the Transmission Owner's (TOs) short-term capital improvement plans. The STUDY includes normal conditions (Category A) and single contingency analysis (Category B) that outage and monitor all transmission facilities rated 100 kV and above and identifies any elements that perform outside the screening criteria. In addition, this 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)

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[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-003-0

[4] Consistent with R1.1.1 and R1.1.2 of NERC TPL-005-0

The Methodology Section of this STUDY discusses the choice of Category C events simulated in the STUDY.

NERC defines Year One as the first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. 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.

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 identified by the responsible entity.

CASE ASSESSMENT

Cases are assessed for possible Rate C violations 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, C5 & C3 Gens) against the Rate C. The entities address potential BES screening violations using one of four possible methods; pre-contingency switching, pre-contingency dispatch adjustment, documentation of a higher Rate C or automatic 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 additions, planned transmission improvements and projected firm transmission services. The FRCC Region Load reflects a lower growth as a result of the lingering effects of the economic recession in Florida. The information contained in the cases representing the near-term is comprised of planned projects with a higher degree of confidence. The confidence level of these major assumptions decreases within 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. All study years in the near-term planning horizon were used to represent summer peak and winter peak critical system conditions.[5] Transmission and generation expansion plans for the first five years have a higher degree of certainty.

[5] 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-003-0

Operator intervention or remedial actions can be taken to restore normal continuous steady state conditions. 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 2019 Summer Peak case and the 2018/19 Winter 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 long lead-time for implementation and identification of specific operator remedial actions.[6] The identification of preliminary proposed projects and the plan to study alternatives can be acceptable corrective plans within the longer-term horizon.

Demand Level Selection. The STUDY includes two load levels (Summer Peak and Winter Peak) as the most critical system condition. Additionally, select Off-Peak load levels were studied to represent system performance over the range of forecast system demands.[7]

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 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 selected to represent the operating range of load levels experienced within the FRCC Region.

Inter-Regional Reliability Assessment.

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

[7] 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-003-0

The Inter-Regional Reliability Assessment covers both the near-term[8] and longer-term[9] portions of the planning horizon. The 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 three bus levels within the SERC Region[10](accounting for approximately 118 buses) are monitored. In addition, the assessment includes additional outages of two or more BES transmission facilities within the FRCC Region (Category C2 and C5). All facilities rated 100 kV and above within the FRCC Region and 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 transmission facilities rated 100 kV and above 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 transmission system facilities rated 100 kV and above were performed for the FRCC Region. All facilities rated 100 kV and above 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 – The C3 contingency analysis included the following:

1. Loss of two independent transmission facilities with manual system adjustments within the FRCC Region rated 100 kV and above.
2. Loss of two independent transmission facilities with manual system adjustments within the identified SERC Region.
3. Loss of two independent transmission facilities with manual system adjustments within a subset of all the facilities identified within the SERC Region and facilities in the Northern portion of the FRCC Region (FPL, JEA, PEF and SEC) rated 100 kV and above.

All transmission facilities rated 100 kV and above 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

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[8] Consistent with R1.2 of NERC TPL-005-0
[9] Consistent with R1.3 of NERC TPL-005-0
[10] Consistent with R1.4 of NERC TPL-005-0

rated 100 kV and above were performed for the FRCC Region. All facilities rated 100 kV and above 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 Standards TPL-001-0.1, TPL-002-0b and TPL-003-0a require that the transmission system 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. Under Category B and C events, planned/controlled loss of demand or curtailment of firm power transfers is permitted as footnoted in Table 1 or the TPL Standards. 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 transmission facilities rated 100 kV and above are monitored and compared to the applicable thermal rating and/or voltage screening criteria throughout all study cases. Any facility loadings exceeding the equipment thermal rating and/or voltage screening criteria are reviewed by the respective TOs and case adjustments are provided and get 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.[11]

Category B Analysis. For Categories B1, B2 and B3 events, all transmission facilities rated 100 kV and above are singularly removed from service throughout all study cases.[12] Contingencies resulting in branch loadings exceeding thermal ratings and/or voltage screening criteria are reviewed by the TOs. Remedies are then provided by the TOs 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.

Testing of categories B1, B2 and B3 events as described above is sufficient for evaluating the system performance for Category B events shown in Table 1. Category B4 was not examined due to the absence of HVDC facilities within the FRCC Region. Within the FRCC Region, there are no control devices such as static VAR controllers (SVC), high voltage direct current systems (HVDC), flexible AC transmission systems (FACTS), and static compensators (STATCOM).

Category B Simulation Study Methodology

The Category B1 – B3 events associated with TPL-002-0 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

[11] Consistent with R1.3.4 of NERC TPL-001-0.1

[12] Consistent with R1.3.1 and R1.5 of NERC TPL-002-0b

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-002-0 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 in imbalance with the mechanical input generator output power. 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.

Category C Analysis Selection.[13] Category C1, C2, C3 and C5 of Table 1 are used to determine system performance under multiple contingency scenarios as they are credible and 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 STUDY.

[13] Consistent with R1.3.1 and R1.5 of NERC TPL-003-0

Category C1 (Bus Section failure) Analysis. Bus Section failure events that result in the loss of two or more transmission system elements 100 kV and above that exceed the thermal and/or voltage screening criteria are reviewed by the TOs for all near-term and longer-term planning horizon cases. Remedies are provided by TOs 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 transmission system elements 100 kV and above that exceed the thermal and/or voltage screening criteria are reviewed by the TOs for all near-term and longer-term planning horizon cases. Remedies are provided by TOs to resolve potential screening criteria exceptions (See Attachment D).

Category C3 (lines) Analysis. The 2014 FRCC summer season load flow databank case was used to evaluate multiple contingency events that result in the loss of two independent transmission elements. Power Technologies, Inc. (PTI) MUST software was used to perform this evaluation on a zonal (combined zones) basis. All possible line combinations rated 100 kV and above were evaluated sequentially within each zone. Results showing line loadings greater than 130% of rate "B" 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 TO for the double contingency, as long as the double did not result in a rate "C" thermal overload. 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 TOs and remedies are developed to address any resultant thermal and/or voltage potential screening criteria exceptions (See Attachment E).

The potential number of combinations of matched pairs even when restricted to geographic zones can be over 90,000. The process was developed to comply with TPL-003-0a and replicate system operator actions in the event of an initial outage followed by a second outage. In order to perform this analysis, the FRCC Region was divided into geographical zones and the independent outages were restricted to the individual zones. Paired outages that resulted in thermal loadings greater than 130% of rate "B" and/or voltages less than 0.88 per unit were screened to be studied in more detail as described above.

This geographical limitation on pairs results in practical set of scenarios to review. It is possible that two lines in different zones could interact and affect the transmission system. However, the event would be less severe and similar in response to a double contingency within a zone. Some zones overlap to ensure that the potential worst case scenarios are covered.

Category C3 (generators) Analysis. FRCC load flow databank cases representing summer 2014 (peak and off-peak - 80% load), summer 2019, winter

2014/15 and winter 2019/20 peak seasonal 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 transmission element rated 100 kV and above or an additional generating unit.

Selected generation units used to perform the multiple contingency analyses are:

- Crystal River Unit 3
- St. Lucie Unit 1
- Seminole Unit 2
- Sanford Unit 5 CC
- Stanton Unit A CC
- Ft Myers Unit 2 CC (steam portion plus two CTs)

The units listed above were selected due to their large size and geographic diversity within the FRCC Region. These units sufficiently represent the most severe regional unit outages since the loss of any these units requires the owner utility to make up the generation from other resources.

Events that cause facilities to exceed the thermal rating of 100% of Rate "B" and/or voltages screening criteria were reviewed by the TOs. The individual TOs provide remedies for the resolution of these potential screening criteria exceptions (See Attachment E).

Category C5 Analysis. Event(s) 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 and are simulated in all near and longer-term planning horizon cases. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the TOs. Remedies are provided by TOs to resolve potential screening criteria exceptions (See Attachment F).

Protection System Analysis. Contingency Event(s) resulting in the loss of two or more circuits or elements as the result of existing and planned protection systems[14] rated 100 kV and above are evaluated. These contingencies are performed separately due to limitation in automated softwar capability. Examples of these contingencies Event(s) are; three terminal lines and events resulting in the loss of appropriate generating units of a combined cycle generator (gas and steam turbine) are simulated in all near and longer-term planning horizon cases. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the TOs to resolve potential screening criteria exceptions (See Attachment F). The evaluation of contingency loss of individual segments of standard two terminal lines has consistently produced more stringent results than produced from corresponding breaker to breaker contingencies.

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

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. If the potential likelihood of protection system actions are identified, then further simulation of those actions are imposed on the system to determine resulting system conditions and so on. [TPL-002-0b and TPL-003-0a R1.3.10]

Category C and D contingencies are addressed in the FRCC Extreme Event Study[15] 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 2012 – 2016 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.

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.[16] 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 facilities (100 kV and above) are monitored to ensure facility voltage criteria are met. Screening of simulation voltage exceptions (those facilities with voltages outside applicable entity 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 TOs require coordinated remedies. The TOs discuss various options, including remedial control, switching of transmission assets and/or coordinated generation re-dispatch, in order to develop coordinated remedies that address the transmission concerns.

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[15] The FRCC has reviewed the study cases used for the FRCC Extreme Events Study dated November 28, 2011 and confirms these study cases continue to be applicable to the current near term planning horizon cases (2012 – 2016) with respect to the BES performance for the Category C6 – C9 fault scenarios associated with the TPL-003-0 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.

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

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 TO provides a mitigation plan addressing each criteria exception. Criteria exceptions that cannot be resolved by feasible mitigation plans will require facilities to be planned and constructed to ensure future transmission adequacy.

VI. RESULTS AND OBSERVATIONS

The results of this 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 STUDY are discussed separately in the Near-term and Longer-term sections.

NEAR-TERM

The STUDY shows that for Category A conditions and Category B and C events, the performance of the transmission system was adequate and in compliance with NERC Transmission Planning Standards for the near-term planning horizon and are supported by documentation provided by the individual TOs.

LONGER-TERM

The STUDY for the longer-term planning horizon is evaluated to identify possible emerging concerns, monitor known concerns, monitor the effects of planned projects and identify 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 expansion plans and the location and timing of projected loads. In addition, the transmission expansion plans representing the longer-term of this STUDY are typically under review by most TOs still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most 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 were identified.

Based upon a review of the STUDY results, some observations can be made as to the performance of the power system under Category C3 (lines) events. In general, the possible results of these events can be mitigated by adjusting the power system to be ready for the next event in order to fully comply with NERC TPL Standards.

INTER-REGIONAL.

The results for normal, single and multiple contingency events for facilities within the FRCC Region and identified facilities within the SERC Region meet NERC Reliability Standards. No FRCC or SERC contingency events resulted in a transmission facility screening criteria exception.

VII. CONCLUSION

The STUDY of the BES with the FRCC Region concludes that potential thermal and voltage screening criteria exceptions can be resolved by operator intervention meeting NERC TPL Standards. These resolutions were thoroughly reviewed by the TOs 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: 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: 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 2013, 2014 (peak, 80%, 60%) 2015, 2016, 2017, 2019 and winter 2012/13, 2013/14, 2014/2015, 2015/16, 2016/17, 2018/19, as represented in the FRCC FY10 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 130% of rate B.

- 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.[23]

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

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

- Modeling of events included the response of existing and planned controlled devices as reported by the owner of the device.[24]

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

- Includes all existing and planned transmission facilities, generating units, and Reactive Power resources in the base cases.[25]

- 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.[26]

- Includes all existing and planned protection systems, including backup and redundant systems[27].

- Incorporates the applicable Nuclear Plant Interface Requirements (NPIR) provided by transmission entities responsible for providing services related to NPIRs[28].

A.2 – Methodology

The FRCC summer 2013, 2014, 2015, 2016, 2017, 2019 and winter 2012/2013, 2013/14, 2014/15, 2015/16, 2016/17, 2017/18, 2018/19 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 thermal and voltage exceptions. All 100kV and above facilities are singularly outaged. FRCC buses 100kV and above are observed for voltages outside the general screening criteria of 95% - 105%, or the specific criteria of individual

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[24] Consistent with R1.3.11of NERC TPL-002-0b and TPL-003-0

[25] Consistent with R1.3.8 of NERC TPL-001-0.1, TPL-002-0b and TPL-003-0

[26] Consistent with R1.3.12 of NERC TPL-002-0b and TPL-003-0

[27] Consistent with R1.3.10 of NERC TPL-002-0b, TPL-003-0

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

utilities. Branches connected to these buses are monitored for overloads above their "A" (normal rating) for Category A and "B" (emergency ratings) for Category B. Any contingencies that resulted in branch loadings exceeding 100% of the "B" rating or bus voltages outside the general screening criteria are summarized using the MUST software. The resulting MUST 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 MUST 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-002-0 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-002-0 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 in imbalance with the mechanical input generator output power. If the fault is on the system long enough, the generator will experience enough acceleration that it can not 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-003-0a 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 includesbuses 100kV and above which are observed for bus voltages outside the screening criteria. Branches connected to these buses are monitored for loadings above their "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 100 kV and above which are observed for bus voltages outside the screening criteria. Branches connected to these buses are monitored for loadings above their "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 2014 summer season was selected by the FRCC TWG for the more detailed Category C3 steady-state portion of this study. Two years of the near term are studied annually under Category C3 events, the upcoming summer 2012 (as part of the ORS study) and the summer 2013 as part of this TWG study. 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 2014 is expected to be similar to the performance in years 2012 and 2013, therefore summer 2014 was used to represent the near term. Years beyond 2014 become less certain in terms of planned projects and transactions and therefore, performing an in depth study of these years would provide information of limited value. Summer 2014 allows adequate lead time to address potential system performance concerns related to Category C3 events. Using the PTI's MUST software, the FRCC Region was evaluated on a zonal basis. This approach was taken to accommodate program size limitations. All combination of lines 100 kV and above within the zones were evaluated. Double contingency outages causing line loadings greater than 130% of rate "B" 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 develops 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 reviews the candidate contingencies and develops remedies to address any thermal and/or voltage exceptions. In addition, any candidate contingency that results in excessive loading and wide spread low voltages is treated as a contingency that has the potential to create a cascading outage, and is 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-003-0a, 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. The FRCC requested entities to

provide system operating limits for those facilities that exceeded the screening criteria. 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 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-003-0a, 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.

<u>Appendix B -</u> RATE C SCREENING PROCEDURE

Note: Exceeding Rate C does <u>not</u> 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 (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 (SOL) for the facility that is greater than the value shown in the case and supply an IDEV to apply to case.
d. Document that there is a protective system or Special Protection Scheme (SPS) that would prevent the facility from exceeding the SOL.

Step 2: Re-run cases with all supplied corrections against Rate C for contingencies (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:

<u>For BES Rate C Potential Violations</u>

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.

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 these Category C2, C3 and C5 contingencies for which the steady-state results indicate a severe response (i.e. transmission voltages lower than 90% or overloads greater than 140%).

Category C and D contingencies are addressed in the FRCC Extreme Event Study[29]. 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 2011 – 2015 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.

[29] The FRCC has reviewed the study cases used for the FRCC Extreme Events Study (dated November 28, 2011) and confirms these study cases continue to be applicable to the current near term planning horizon cases (2012 – 2016) with respect to the BES performance for the Category C6 – C9 fault scenarios associated with the TPL-003-0 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 3. Transformer 2. Transmission Circuit 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-003-0a — 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-003-0a_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
- Clewiston Electric
- Fort Pierce Utility Authority
- City of Green Cove Springs
- Keys Energy Services
- Kissimmee Utility Authority
- Lake Worth Utility
- Ocala Utility Services
- Florida Municipal Power Agency

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

TRANSFER CAPABILITY ASSESSMENT: FLORIDA / SOUTHERN INTERFACE

Projections for 2013 & 2015 Assessment Years

Final*
October 25, 2011

(*CEII Information Removed)

TRANSFER CAPABILITY ASSESSMENT:
FLORIDA / SOUTHERN INTERFACE

Projections for 2013 & 2015 Assessment Years

Final
October 25, 2011

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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 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 2013 and 2015 summer transfer capabilities are representative of the June through September time period and the 2013/2014 and 2015/2016 winter transfer capabilities are representative of the December through February time period. Note that various operating procedures are required to achieve these results. Information regarding these operating procedures is contained later in the report and in the appendices.

TABLE 1	TRANSFER CAPABILITY (MW)	
Season[1]	**SOU to Fla**	**Fla to SOU**
2013 Summer	3700	900
2013/2014 Winter	3700	2000
2015 Summer	3700	1000
2015/2016 Winter	3700	1900

INTRODUCTION

The primary purpose of this joint 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. Transfers across the Florida / Southern transmission interface were simulated for the 2013 summer, 2013/2014 winter, 2015 summer, and 2015/2016 winter time periods. Transfers were evaluated based on the methodologies and criteria of the FRCC and the Southern Balancing Authority (SBA).

The Southern models were based on the latest available series of the 2011 Southern Balancing Authority base cases. The FRCC models were based on the 2011 FRCC data bank (FY11, pass2C2). 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. A list of the tested transmission contingencies is provided in Table 3. 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] Summer Season: June 1 – September 30, Winter Season: December1 – February 29

The methodology used for the determination of Southern to Florida transfers assumes that all facilities expected to be available are in service. The interchange assumptions for the transfer capability test cases start with firm interchange commitments and model additional transfers in accordance with the allocation agreements. The voltage stability of key single and double contingencies is tested using a Power/Voltage ("P/V") sensitivity method. For those transfers that are limited by voltage security, 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 transfer capability assumes the unavailability of a generating unit with the most significant effect on the interface capability. The Vogtle #1 generating unit was modeled as offline in the Southern import cases with a redispatch of the Southern area. 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. The load in the FRCC region was reduced to 90% of the seasonal peak to evaluate Florida to Southern transfers for the summer and winter seasons. Importing utilities maintain their peak load during these transfers.

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 transfer distribution factors lower than 3%) 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 SOUTHERN TO FLORIDA TRANSFERS

2013 Summer Period

The firm transfer capability of 3700 MW was found to be attainable for the 2013 summer conditions. Higher transfers were found to be limited by voltage security concerns for the Category C circuit breaker outage that results in the outage of the Duval - Thalmann 500 kV line and the Duval – Rice 500 kV lines.

2013/2014 Winter Period

The firm transfer capability of 3700 MW was found to be attainable for 2013/2014 winter conditions. Higher transfers were found to be limited by voltage security concerns for the Category C circuit breaker outage that results in the outage of the Duval - Thalmann 500 kV line and the Duval – Rice 500 kV lines.

2015 Summer Period

The firm transfer capability of 3700 MW was found to be attainable for the 2015 summer conditions. Higher transfers were found to be limited by voltage security concerns for the Category C circuit breaker outage that results in the outage of the Duval - Thalmann 500 kV line and the Duval – Rice 500 kV lines.

2015/2016 Winter Period

The firm transfer capability of 3700 MW was found to be attainable for the 2015/2016 winter conditions. Higher transfers were found to be limited by voltage security concerns for the Category C circuit breaker outage that results in the outage of the Duval - Thalmann 500 kV line and the Duval – Rice 500 kV lines

ASSESSMENT of FLORIDA TO SOUTHERN TRANSFERS

2013 Summer Period

The firm capability of 900 MW transfer capability was found to be attainable for the 2013 summer conditions. At higher transfers, the outage of the West McIntosh – McCall Road 500 kV line causes the Hatch - Vidalia 230 kV line to exceed its thermal rating of 486 MVA.

2013/2014 Winter Period

The firm capability of 2000 MW was found to be attainable for the 2013/2014winter period. At higher transfers, the outage of the Martin West – Silver Springs 230 kV line causes the Bronson - Newberry 230 kV line to exceed its thermal rating of 478 MVA.

2015 Summer Period

The firm capability of 1000 MW was found to be attainable for the 2015 summer conditions. At higher transfers, the outage of the West McIntosh – McCall Road 500 kV line causes the Hatch - Vidalia 230 kV line to exceed its thermal rating of 486 MVA.

2015/2016 Winter Period

The firm capability of 1900 MW was found to be attainable for the 2015/2016 winter conditions. At higher transfers, the outage of the West McIntosh – McCall Road 500 kV line causes the Hatch - Vidalia 230 kV line to exceed its thermal rating of 545 MVA.

Table 3 - Contingency List

500 kV lines

- Bonaire to Hatch
- Duval to Hatch
- Duval to Thalmann
- Farley to Snowdoun
- Farley to Raccoon Creek
- North Tifton to Raccoon Creek
- Fortson to N. Tifton
- Thalmann to McCall Road
- McCall Road to West McIntosh
- Vogtle to West McIntosh
- Crystal River to Brookridge
- Crystal River to Central Florida
- Poinsett to Rice
- Poinsett to Martin
- Poinsett to Midway
- Duval to Poinsett
- Duval to Rice

500/230 kV Transformers

- Farley #1
- Poinsett
- Thalmann
- West McIntosh #1
- West McIntosh #2
- Rice

230 kV lines

- West Brunswick to Thalmann
- Colerain to Thalmann
- Colerain to Kingsland
- SOWEGA to Albany
- Raccoon Creek to Mitchell
- Raccoon Creek to SOWEGA
- Raccoon Creek to North Camilla
- S. Bainbridge to Sinai Cemetery
- Lansing Smith to Callaway
- Lansing Smith to Sinai Cemetery
- Farley to South Bainbridge
- Farley to Sinai Cemetery
- Farley to Cotton Wood
- North Tifton to Pinegrove
- Kingsland to Yulee
- Hatch to Eastman Primary
- Pinegrove to Sterling
- Sterling to Suwannee
- Bonaire to Dorsett
- East Moultrie to West Valdosta
- North Tifton to East Moultrie
- S. Bainbridge to Sub #20
- Callaway to Port St. Joe
- Duval to Springbank
- Greenland to Switzerland
- Ft. White to Newberry
- Ft. White to Ginnie
- Ft. White to Suwannee
- Crystal River to King Road
- Normandy to Brandy Branch
- Brevard to Sarno
- Malabar to Hield

115 kV lines

- Sinai Cemetery to Woodruff

Generating Unit Contingencies (Southern to Florida transfers)

- Crystal River #3
- Manatee #1
- St. Lucie #2
- Turkey Point #4
- Turkey Point #5 steam
- W County #2 steam

Double Contingencies

- Duval to Thalmann 500 kV & Duval to Rice 500 kV
- Duval to Hatch 500 kV & Duval to Poinsetta 500 kV
- Duval to Thalmann 500 kV & Thalmann to McCall Road 500 kV

Appendix A
Total Transfer Capabilites
contains CEII information
and not included

Appendix B
Operating Procedures
contains CEII information
and not included