RATE SCHEDULE NO. 138

SOUTHERN COMPANY SYSTEM
INTERCOMPANY INTERCHANGE CONTRACT

BETWEEN

ALABAMA POWER COMPANY,
GEORGIA OWER COMPANY,
GULF POWER COMPANY,
MISSISSIPPI POWER COMPANY,
SOUTHERN POWER COMPANY,
AND
SOUTHERN COMPANY SERVICES, INC.

Dated May 1, 2007

SOUTHERN COMPANY SYSTEM INTERCOMPANY INTERCHANGE CONTRACT

ARTICLE I - RECITALS

Section 1.1: This contract is made and entered into this 1st day of May, 2007, by and between Alabama Power Company, a corporation organized and existing under the laws of the State of Alabama with its principal office in Birmingham, Alabama; Georgia Power Company, a corporation organized and existing under the laws of the State of Georgia with its principal office in Atlanta, Georgia; Gulf Power Company, a corporation organized and existing under the laws of the State of Florida with its principal office in Pensacola, Florida; Mississippi Power Company, a corporation organized and existing under the laws of the State of Mississippi with its principal office in Gulfport, Mississippi; and Southern Power Company, a corporation organized and existing under the laws of the State of Delaware with its principal office in Birmingham, Alabama, all such companies being hereinafter collectively referred to as the "OPERATING COMPANIES"; and Southern Company Services, Inc., a subsidiary service company ("AGENT" or "SCS").

W I T N E S S E T H:

Section 1.2: WHEREAS, the common stock of the OPERATING COMPANIES is owned by The Southern Company, a public utility holding company; and

Section 1.3: WHEREAS, the OPERATING COMPANIES can be operated as an integrated electric utility system; and

Section 1.4: WHEREAS, the OPERATING COMPANIES have so operated their respective electric generating facilities and conducted their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among themselves, the most recent of which being The Southern Company System Intercompany Interchange Contract dated February 17, 2000, as modified effective July 1, 2006 to reflect an intra-corporate reorganization ("the 2000 Contract"); and

Section 1.5: WHEREAS, the OPERATING COMPANIES desire to replace the 2000 Contract with an amended and restated contract; and

Section 1.6: WHEREAS, all of the OPERATING COMPANIES will continue to share in all of the benefits and burdens of this IIC, including complying with operating, dispatch and reserve requirements, participating in opportunity sales transactions, and bearing responsibility for their portion of purchases.

Section 1.7: NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements hereinafter stated, the OPERATING COMPANIES agree and contract as follows:

ARTICLE II - TERM OF CONTRACT

Section 2.1: This contract will be referred to as the Southern Company System Intercompany Interchange Contract ("IIC"). The IIC shall become effective as provided in Section 2.2 hereof, and shall continue in effect from year to year thereafter subject to termination as provided hereinafter. When this IIC has become effective, it shall supersede and replace the 2000 Contract, and references to a section of such superseded intercompany interchange contract in other agreements of the OPERATING COMPANIES shall be taken to mean reference to the section of substantially like import in this IIC.

Section 2.2: This IIC was submitted as part of a filing in compliance with the orders of Federal Energy Regulatory Commission ("Commission" or "FERC") in Southern Company Services, Inc., Docket Nos. EL05-102, et al., 117 FERC ¶ 61,021 (2006) and Southern Company Services, Inc., Docket Nos. EL05-102, et al., 119 FERC ¶ 61,065 (2007). Pursuant to the Commission's acceptance of such compliance filing, this IIC is effective as of May 1, 2007.

Section 2.3: This IIC may be terminated at any time by mutual agreement of the OPERATING COMPANIES or may be terminated at any time by any OPERATING COMPANY by its giving to each of the other OPERATING COMPANIES and the AGENT written notice of its election to so terminate its participation in this IIC at least five (5) years prior to the date of termination. This IIC shall continue in full force and effect as to each OPERATING COMPANY until terminated as hereinabove provided.

ARTICLE III - PRINCIPAL OBJECTIVES OF INTERCOMPANY INTERCHANGE CONTRACT

Section 3.1: The purpose of this IIC is to provide the contractual basis for the continued operation of the electric facilities of the OPERATING COMPANIES in such a manner as to achieve the maximum possible economies consistent with the highest practicable reliability of service, with the reasonable utilization of natural resources and effect on the environment, and to provide a basis for equitably sharing among the OPERATING COMPANIES the costs associated with the operation of facilities that are used for the mutual benefit of all the OPERATING COMPANIES.

Section 3.2: It is recognized that reliability of service and economy of operation require that the energy supply to the system be controlled by means of centralized economic dispatch and that this will require adequate communication facilities and the provision of economic dispatch computer facilities and automatic controls of generation.

Section 3.3: It is recognized that the IIC provides for the retention of lowest cost energy resources by each OPERATING COMPANY for its own customers. Energy in excess of that necessary to meet each OPERATING COMPANY's requirements is delivered to the Pool as Interchange Energy and may include: (i) energy generated from plants other than conventional hydro or nuclear; and (ii) purchased energy.

Section 3.4: It is recognized that, under this IIC, each OPERATING COMPANY will share in the benefits and pay its share of the costs of coordinated operations as agreed upon in accordance with the terms hereof. All costs and revenues associated with wholesale transactions under this IIC will be shared among all OPERATING COMPANIES on a comparable basis through the application of the governing procedures and methodologies to all such OPERATING COMPANIES.

Section 3.5: It is recognized by the OPERATING COMPANIES that coordinated electric operation contemplates minimum cost of power supply upon the interconnected system, consistent with service requirements and other operating limitations. Benefits of integrated operation accruing to the respective OPERATING COMPANIES are predicated upon cooperative efforts toward this objective and are so reflected in all IIC determinations.

Section 3.6: This IIC is applicable only to the transactions described herein, as specifically set forth in ARTICLE VII – INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, ARTICLE VIII – INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES, and ARTICLE IX – PROVISION FOR OTHER INTERCHANGE TRANSACTIONS. Otherwise, sales between the OPERATING COMPANIES (including, but not limited to, sales from Southern Power Company to the other OPERATING COMPANIES or sales from the other OPERATING COMPANIES to Southern Power Company) require an appropriate filing under Section 205 of the Federal Power Act and acceptance thereof by the Commission.

ARTICLE IV - ESTABLISHMENT OF OPERATING COMMITTEE AND DESIGNATION OF AGENT

Section 4.1 – Establishment of Operating Committee: A designated representative from each of the OPERATING COMPANIES, together with a designated representative of the AGENT who shall act as chairman, shall form and constitute an Operating Committee to meet as needed to determine the methods of operation hereunder.

Section 4.2 – Duties of Operating Committee: The Operating Committee's areas of responsibility include such matters as developing the concepts, terms and conditions of this IIC; providing guidance and direction to the AGENT regarding economic power system operations and the costs associated therewith; reviewing and recommending generation expansion plans for approval by the respective OPERATING COMPANIES pursuant to Section 4.3; and addressing other power system matters that relate to the overall coordinated operation of the Southern electric system. Each OPERATING COMPANY representative has one vote and all decisions must be unanimous.

Section 4.3 – Review and Recommendation of Generation Expansion Plans: The Southern Power Company representative on the Operating Committee will not participate in reviewing and recommending generation expansion plans of the other OPERATING COMPANIES or the system, nor will the Southern Power Company representative have access to materials developed in conjunction with the formulation of such generation expansion plans. Notwithstanding Section 4.2 above, the Southern Power Company representative shall not be eligible to vote with respect to these expansion plans. Moreover, Southern Power Company will not receive market information from the other OPERATING COMPANIES through its participation in the Operating Committee.

Section 4.4 – Transmission Information: The Operating Committee does not have any duties or responsibilities with respect to transmission-related activities (including transmission reliability) and, consistent with the Standards of Conduct, will not receive non-public transmission information. The IIC (including Operating Committee membership) is not to serve as a means whereby non-public transmission information is shared in a manner contrary to the Commission's Standards of Conduct. Further, Southern Power Company is to be treated as an Energy Affiliate under the Commission's Standards of Conduct and therefore cannot receive any non-public transmission information.

Section 4.5 – Operating Committee Discretion: Certain provisions of the Manual afford a degree of latitude to the Operating Committee with regard to decisions that it is authorized to make thereunder. When such discretion is exercised, the AGENT will summarize the decision in an informational filing to be submitted to the Commission within ten (10) business days.

Section 4.6 – Designation of AGENT: SCS, as a party to this IIC, is designated as AGENT of the OPERATING COMPANIES for purposes of this IIC. In addition, SCS may serve as AGENT and represent the OPERATING COMPANIES, or any of them, in all things to be done in the execution of and operation under existing contracts with nonaffiliated utilities or entities (hereinafter referred to as "OTHERS"), or contracts supplemental thereto.

Section 4.7 – Duties of AGENT: The AGENT is responsible for all administrative and coordination functions in order to effectuate the terms and conditions of this IIC. From time to time, the OPERATING COMPANIES, or any of them, may also have contracts with OTHERS that provide for the purchase and/or sale of capacity and/or energy by the OPERATING COMPANIES. The AGENT will make the payments associated with purchases under these contracts and under any other contracts or arrangements under which it acts as agent for the OPERATING COMPANIES. Each OPERATING COMPANY will reimburse the AGENT for its portion of such total payments in accordance with the arrangement in effect with respect to the particular contract. Similarly, the AGENT will collect the payments due for sales under these contracts (and under any other contracts or arrangements under which it acts as agent) and will distribute such payments among the OPERATING COMPANIES in accordance with the arrangement in effect with respect to the particular contract.

Section 4.8 – Term of Agency: The provisions of this IIC providing for authority for the AGENT to act on behalf of the OPERATING COMPANIES, or any of them, shall be deemed to refer, insofar as applicable, to all contracts under which the AGENT acts as agent for the

OPERATING COMPANIES and, notwithstanding anything to the contrary in ARTICLE II hereof, this IIC shall continue in effect insofar as it pertains to other contracts under which the AGENT acts as agent for the OPERATING COMPANIES during the life of any such contracts. The OPERATING COMPANIES may, however, designate a new agent to act hereunder by giving thirty (30) days written notice thereof to the AGENT, whereupon such new agent shall be the AGENT hereunder.

ARTICLE V - OPERATION AND MAINTENANCE OF ELECTRIC GENERATING FACILITIES

Section 5.1: The OPERATING COMPANIES agree to maintain their respective electric generating facilities in good operating condition and to operate such facilities in coordination with those of the other OPERATING COMPANIES as an integrated electric system in accordance with determinations made from time to time by the Operating Committee in order that an adequate power supply shall be available to meet the requirements of the customers of the respective parties hereto at the lowest cost consistent with a high degree of service reliability.

Section 5.2: With respect to its participation in this IIC, Southern Power Company may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool ("Pool resources"), but it may not otherwise have access to information regarding the operation of Pool resources of the other OPERATING COMPANIES.

ARTICLE VI - INCORPORATION OF THE ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION MANUAL

Section 6.1 – Incorporation of Manual: The mechanics and methods for determining the charges for reserve sharing capacity and for energy purchased and sold between the OPERATING COMPANIES, the monthly capability requirement determinations, and the monthly billings and payments between the OPERATING COMPANIES are described in detail in the Allocation Methodology and Periodic Rate Computation Manual ("Manual") attached hereto and incorporated herein by reference. The Manual also supplies more detailed explanation of provisions of this IIC and is necessary to effectuate its intent.

Section 6.2 – Purpose of Manual: The Manual contains a description of the methodology and procedure used to calculate the charges provided for in this IIC. The OPERATING COMPANIES recognize that the costs underlying these charges will change during the term of this IIC for reasons such as changes in loads, investment and expenses, as well as the addition of electric generating resources. Thus, in order for the OPERATING COMPANIES to share equitably in the costs associated with this IIC, it will be necessary to revise or update, on a periodic basis, the cost, expense, load and investment figures utilized in the derivation of the charges hereunder. The Manual will serve as a formula rate allowing for periodic revision of the charges to reflect changes in the underlying cost components.

Section 6.3 – Revision of Charges and Regulatory Filings: The Manual provides that charges derived by application of the formula rate will be shown on Informational Schedules. Since the charges under this IIC will be computed in accordance with the formula rate method and procedures established in the Manual, these submissions will not be initial rates or changes in rates that would require a filing and suspension under the Federal Power Act and the applicable

Rules and Regulations of the Commission. On or before November 1 of each year, the Informational Schedules will be submitted to the Commission for informational purposes to show the application of the formula rate and the resulting charges. Work papers will also be included showing a detailed application of the formula rate contained in the Manual.

Section 6.4 – Revision of Manual: If the Operating Committee determines that revisions to the formula rate are appropriate or necessary, it will direct the AGENT to file the revised Manual with the Commission in order to obtain timely approval or acceptance thereof.

ARTICLE VII - INTERCHANGE CAPACITY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 7.1 – Provision for Sharing of Temporary Surpluses or Deficits of Capacity Between Operating Companies: It is a fundamental premise of this IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations. Nevertheless, the OPERATING COMPANIES recognize that in any given year one or more of them may have a temporary surplus or deficit of capacity as a result of coordinated planning or by virtue of load uncertainty, unit availability, and other such circumstances. It is among the purposes of this IIC to share among the OPERATING COMPANIES the benefits and burdens of their coordinated system operations, including the cost associated with such capacity ("Reserve Sharing"). Reserve Sharing among the OPERATING COMPANIES is accomplished pursuant to transactions (referred to as "purchases" and "sales") effectuated on a monthly basis in accordance with ARTICLES IV and V of the Manual.

Section 7.2 – Charge for Monthly Reserve Sharing Among the OPERATING COMPANIES: The OPERATING COMPANIES recognize that capacity reserves in the Pool are predominantly made up of peaking plant or equivalent purchased resources. Accordingly, the monthly charge for Reserve Sharing among the OPERATING COMPANIES will be based on the most recently acquired peaking plant resource that is available for year-round operation and scheduling. Each OPERATING COMPANY's monthly charge for reserve capacity sold to the Pool is developed in accordance with the formula rate set out in ARTICLE V of the Manual. The monthly capacity charge for each OPERATING COMPANY, as developed in accordance with such formula rate, will be shown on Informational Schedules. Each selling OPERATING COMPANY will sell at its charge shown on such Informational Schedules and the buying OPERATING COMPANIES will purchase at the weighted average charge of the sellers.

ARTICLE VIII - INTERCHANGE ENERGY TRANSACTIONS BETWEEN THE OPERATING COMPANIES

Section 8.1 – Provision for Interchange Energy: Coordinated system operation, utilizing principles of centralized integrated system economic dispatch, results in energy transfers among the OPERATING COMPANIES. Such energy transfers are accounted for on an hourly basis and are referred to as "Interchange Energy." The methodology for determining the amount of Interchange Energy supplied to or purchased from the Pool is set out in ARTICLE II of the Manual. Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 8.2 – Charge for Interchange Energy: The charge for Interchange Energy sales by an OPERATING COMPANY during any hour will be based on the variable costs of the generating resources that are considered as having supplied the Interchange Energy. The methodology for determining the charges for Associated and Opportunity Interchange Energy sales to the Pool during any hour is set out in ARTICLE III of the Manual.

ARTICLE IX - PROVISION FOR OTHER INTERCHANGE TRANSACTIONS

Section 9.1 – Assignable Energy: Assignable Energy is defined as energy derived from internal sources or from OTHERS at a cost that renders it unusable from an economic dispatch perspective. Assignable Energy is assigned to one or more of the OPERATING COMPANIES consistent with the purpose for which it is acquired. Such assignment will be accomplished by first identifying the beneficiary (or beneficiaries) of the Assignable Energy and then determining the appropriate share for each such OPERATING COMPANY. For example, these shares might be based on a Peak Period Load Ratio ("PPLR") in proportion to the PPLRs of other beneficiaries or weighted participation in a bilateral sale. Once assigned, Assignable Energy will not be delivered to the Pool unless it becomes economically usable on the integrated system.

Section 9.2 – Hydroelectric Operation During Periods of Minimum Steam Operations: During certain periods of the year when unusually good flow conditions prevail, certain steam generating units may be taken out of service to increase the utilization of hydro energy. The OPERATING COMPANY having such hydro generation may elect to take a fossil fired generating unit out of service. In the alternative, if another OPERATING COMPANY takes a fossil fired generating unit out of service for the purpose of utilizing such hydro energy, the energy rate between the two OPERATING COMPANIES for that transaction will be the average of the operation and maintenance cost of such hydro energy and the variable cost of the fossil fired generating unit.

Section 9.3 – Tie-Line Frequency Regulation by Hydro Capacity: Tie-line load control and frequency regulation by hydro involves additional costs because of increased expenditures associated with such regulation. The charge for these transactions is computed in accordance with the formula rate contained in ARTICLE VI of the Manual.

Section 9.4 – Pool Transactions with OTHERS: Capacity and energy transactions with OTHERS that are entered into on behalf of the Pool will be governed by the following principles:

Section 9.4.1 – Pool Purchases of Capacity and Energy: The AGENT may periodically purchase capacity and energy from OTHERS for the benefit of the integrated system. Such Pool purchases will initially be allocated at cost to all OPERATING COMPANIES in proportion to their PPLRs, as provided for in ARTICLE X of this IIC. Purchases so allocated may be sold as Interchange Energy when they are economically usable on the integrated system. Adjustments may thereafter be made in order to reconcile any inequitable effects of this process among the OPERATING COMPANIES, with the intent being that none of the individual OPERATING COMPANIES should be adversely impacted by a purchase that benefits the system as a whole. These impacts will be determined through a system simulation that calculates each OPERATING COMPANY's cost of generation that is avoided by the purchase. This avoided cost will be compared on an hourly basis to the cost of the purchase. To the extent the avoided cost exceeds the purchase cost, the effect is "positive" (i.e., cost savings) for that hour. These hourly results will be summed to determine the effect on each OPERATING COMPANY for the day. In situations where individual OPERATING COMPANIES are adversely impacted by a purchase that benefits the system as a whole, such adverse impacts will be offset through a proportional reduction in the positive net benefits realized by the other OPERATING COMPANIES. In the event the net result for the day is negative, that result is shared among the OPERATING COMPANIES on a PPLR basis.

Section 9.4.2 – Pool Sales of Capacity and Energy: The AGENT may from time to time arrange for the sale to OTHERS of capacity and energy available to the Pool at rates provided for in contracts or at rates mutually agreed upon. The capacity and/or energy obligation for the sale, as well as the associated cost, is allocated to each OPERATING COMPANY on a PPLR basis. Payments by OTHERS are also distributed to the respective OPERATING COMPANIES on the basis of PPLRs.

The Pool has the exclusive right to use generation resources committed to the Pool ("Pool resources") to engage in opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week. Neither Southern Power Company nor any of the other OPERATING COMPANIES can use Pool resources for its own benefit in those wholesale opportunity markets. To the extent Southern Power Company engages in other transactions solely for its own benefit, it must do so using personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the other OPERATING COMPANIES.

ARTICLE X – UTILIZATION OF PEAK-PERIOD LOAD RATIOS

Section 10.1 – Certain Allocations and Payments to be Based on Peak-Period Load Ratios: The AGENT is responsible for the annual development of Peak-Period Load Ratios ("PPLRs") for each of the OPERATING COMPANIES. These PPLRs will be utilized for allocation of certain costs, payments, receipts and other obligations, as provided for in this IIC or the Manual. The procedure and methodology for developing the PPLRs are set out in ARTICLE I of the Manual and the resulting PPLR values are shown on an Informational Schedule.

ARTICLE XI - TRANSMISSION SERVICE

Section 11.1 – Applicability of Network Integration Transmission Service: Network Integration Transmission Service ("Network Service") provides for the integration, economic dispatch and regulation of current and planned Network Resources to serve Network Load. Since the OPERATING COMPANIES integrate, economically dispatch and regulate their generating resources to serve their bundled and grandfathered native load ("Native Load") pursuant to this IIC, the associated use of the transmission system is in the nature of Network Service. Except for provisions related to rates and charges, the transmission service provided to these Native Load customers is comparable to Network Service under the Open Access Transmission Tariff ("OATT"). Since the OPERATING COMPANIES' Native Load is specifically included in the determination of the load used to derive the charge for Network Service under the OATT, the OPERATING COMPANIES are bearing a cost responsibility for transactions hereunder comparable to that assigned to other Network Customers.

Section 11.2 – Transmission Service for Other Transactions: All transmission service provided to any or all of the OPERATING COMPANIES (other than service to their Native Load, as described in Section 11.1) is subject to the OATT in all respects, including adherence to the same rates, terms and conditions applicable to other market participants. Any such transmission service will be obtained pursuant to the OATT and/or from other transmission providers.

Southern Power Company specifically commits to take all of its transmission service under the OATT of Southern Companies or from other transmission providers.

ARTICLE XII - BILLING AND PAYMENT

Section 12.1 – Recording and Billing of Energy Transactions: Each OPERATING COMPANY will transmit to the AGENT such data and other information for each hour of the year as is necessary to develop accounting and monthly billing for the various energy transactions specified under this IIC. The AGENT is responsible for assembling all of the data and information and for preparing intercompany energy billing for each month in accordance with the provisions of this IIC. The bills shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.2 – Month-End Adjustment of Daily Energy Determinations: It is recognized that the sum of the daily totals of receipts and deliveries (which are based on instantaneous integrated meters) will not exactly equal corresponding amounts determined at month-end (which are based on accumulating meters). Such differences in energy receipts and deliveries are billed or credited to each OPERATING COMPANY at the average cost of Associated Interchange Energy to the Pool for the month.

Section 12.3 – Billing for Reserve Sharing Transactions: The AGENT is responsible for preparing a monthly bill to the OPERATING COMPANIES for all capacity transactions related to Reserve Sharing, as contemplated by this IIC. The bill shall contain such details as required to permit review and verification by the OPERATING COMPANIES.

Section 12.4 – Billing and Payment Date: The AGENT renders all bills provided for in this IIC not later than the 10th day of the billing month. All payments by the OPERATING COMPANIES are made by the 20th day of the billing month.

Section 12.5 – Billing Corrections: If the AGENT discovers missing or erroneous data of a material nature pertaining to prior billings, a correction adjustment applicable to those billings will be based on the period affected by such missing or erroneous data, but not to exceed forty-five (45) days from the date of such discovery ("correction period"). If the correction period is forty-five days, then the period actually used for the calculation will extend to the beginning of the billing month in which the forty-five day period falls. Interest does not accrue on any such adjustment. The resulting billing correction will be applied as soon as practicable to the regular monthly bill.

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IN WITNESS WHEREOF, the parties hereto have caused this instrument to be signed by their duly authorized representatives on the Operating Committee, which signatures may be set forth on separate counterpart pages.

ALABAMA POWER COMPANY

By: ______________________

Its ______________________

MISSISSIPPI POWER COMPANY

By: ______________________

Its ______________________

GEORGIA POWER COMPANY

By: ______________________

Its ______________________

SOUTHERN POWER COMPANY

By: ______________________

Its ______________________

GULF POWER COMPANY

By: ______________________

Its ______________________

SOUTHERN COMPANY SERVICES, INC.

By: ______________________

Its ______________________

ALLOCATION METHODOLOGY AND PERIODIC RATE COMPUTATION PROCEDURE MANUAL

Section 0.0 – Description and Purpose of Manual: This Manual is provided for in the Southern Company System Intercompany Interchange Contract ("IIC") entered into the 1st day of May, 2007, and contains a formula description of the methodology and procedure used to calculate the charges under the IIC. The Manual is divided into six (6) basic articles as follows:

ARTICLE I	-	Methodology for Determination of Peak-Period Load Ratios
ARTICLE II	-	Methodology for Determination of Amount of Interchange Energy Sold To and Purchased From the Pool
ARTICLE III	-	Rates for Interchange Energy
ARTICLE IV	-	Methodology for Determination of Monthly Amount of Reserve Sharing Capacity To Be Sold To or Purchased From the Pool
ARTICLE V	-	Rate for Monthly Reserve Sharing Capacity for Each Operating Company
ARTICLE VI	-	Rate for Tie-Line Load Control and Frequency Regulation by Hydro Facilities

ARTICLE I

METHODOLOGY FOR DETERMINATION OF PEAK-PERIOD LOAD RATIOS

Section 1.1 – Provision for Peak-Period Load Ratios: This article of the Manual establishes and provides for the annual derivation of Peak-Period Load Ratios ("PPLRs") that are utilized in energy and capacity transactions and in other allocations as provided for in the IIC. These ratios are shown on Informational Schedule No. 1.

Section 1.2 – Methodology for Determining Peak-Period Load Ratios: The Contract Year in the IIC is defined as January 1st through December 31st. The peak period is defined as the fourteen (14) hours between 7:00 a.m. and 9:00 p.m. (Prevailing Central Time) of each weekday, excluding holidays.

The Peak-Period Load Ratios for the Contract Year are based upon the prior year's actual peak period energy in the months of June, July, and August for each OPERATING COMPANY. The system peak period energy is equal to the sum of all the OPERATING COMPANIES' peak period energy, excluding: (i) opportunity transactions with OTHERS that would begin and end during the period from the current hour through Friday (midnight) of the following week; and (ii) any energy sales transactions that are settled on a financial basis.

The Peak-Period Load Ratios are determined by dividing each OPERATING COMPANY's summation of the June, July, and August actual weekday peak-period energy by the total system June, July, and August actual weekday peak-period energy.

ARTICLE II

METHODOLOGY FOR DETERMINATION OF AMOUNT OF INTERCHANGE ENERGY SOLD TO AND PURCHASED FROM THE POOL

Section 2.1 – Methodology for Determination of Amounts of Interchange Energy: Interchange Energy is composed of the following two categories: (i) Associated Interchange Energy (energy purchased or sold to serve an OPERATING COMPANY's obligations other than those related to opportunity sales); and (ii) Opportunity Interchange Energy (energy purchased or sold to meet an OPERATING COMPANY's responsibility for opportunity sales).

Section 2.1.1 – Determination of Associated Interchange Energy: The amount of Associated Interchange Energy purchased or sold is computed hourly on the basis of the following:

1. Net receipts and deliveries, which is the total of energy delivered by each OPERATING COMPANY to all other OPERATING COMPANIES and to OTHERS, less the total of energy received by each OPERATING COMPANY from all other OPERATING COMPANIES and from OTHERS;

2. Adjustments for schedules of the OPERATING COMPANIES and OTHERS, for energy movements received from or delivered to sources within or outside the territory of the OPERATING COMPANIES and settled for under arrangements made for such energy movements;

3. Adjustments for Opportunity Interchange Energy, as determined pursuant to Section 2.1.2 below; and

4. Adjustments to account for: (i) the effects of remote generation to which an OPERATING COMPANY is entitled and remote load for which an OPERATING COMPANY is responsible; and (ii) hydro energy losses due to tie-line frequency regulation.

Section 2.1.2 – Determination of Opportunity Interchange Energy: The amount of Opportunity Interchange Energy purchased or sold is computed hourly for each opportunity sale in order to account for the difference between an OPERATING COMPANY's responsibility for an opportunity sale and the amount of energy actually generated by that OPERATING COMPANY in connection with such sale.

ARTICLE III
RATES FOR INTERCHANGE ENERGY

Section 3.1 – Procedure for Economic Dispatch: Centralized economic dispatch is accomplished by dispatching system generating resources and purchases to meet the obligations of the OPERATING COMPANIES and to supply energy for sales to OTHERS. System generating resources are dispatched based on marginal replacement fuel cost, variable operation and maintenance expenses, in-plant fuel handling costs, emission allowance replacement costs, compensation for transmission losses, and other such energy related costs that would otherwise not have been incurred. A purchase is recognized in economic dispatch on the basis of its energy cost. The above-referenced cost components are collectively referred to as the "variable dispatch cost."

Section 3.2 – Associated Interchange Energy Rate: The Associated Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the incremental resource(s) that serve the collective obligations of the OPERATING COMPANIES. For each hour, an OPERATING COMPANY supplying Associated Interchange Energy to the Pool will receive a payment determined by multiplying the applicable Associated Interchange Energy Rate by the quantity of kilowatt-hours sold to the Pool. For each hour, an OPERATING COMPANY purchasing Associated Interchange Energy from the Pool will be charged an amount determined by multiplying the Associated Interchange Energy Rate by the quantity of kilowatt-hours purchased from the Pool.

Section 3.3 – Opportunity Interchange Energy Rate: The Opportunity Interchange Energy Rate, as determined for each hour, is based on the variable dispatch cost of the resources that supplied such energy in connection with a given opportunity sale. This rate will be applied to each OPERATING COMPANY's energy obligation for that transaction to derive the payment due from such OPERATING COMPANY. The resulting payments will then be used to reimburse the cost of the OPERATING COMPANIES that supplied the Opportunity Interchange Energy.

Section 3.3.1 – Opportunity Interchange Energy Rates Related to Certain Contracts and Other Obligations of the Operating Companies: The OPERATING COMPANIES are currently obligated to supply various types of energy under certain contracts with Florida Power & Light Company, Jacksonville Electric Authority, Florida Power Corporation, and South Mississippi Electric Power Association. For purposes of these contracts, the variable dispatch cost of resources supplying the energy shall be the same as described in Section 3.1 of the Manual, except that blended replacement fuel cost will be used instead of marginal replacement fuel cost.

Section 3.4 – Variable Operation and Maintenance Expenses For Fossil Fired Units: The variable Operation and Maintenance expenses for fossil fired units for the Contract Year are derived by summing the following budgeted/forecasted components for each unit: (i) all operating material, non-labor, and on-site contract labor charged to FERC Accounts 502 and 505 (Fossil Steam); and (ii) all maintenance material, non-labor, and contract labor charged to FERC Accounts 512 and 513 (Fossil Steam), and 553 (Combustion Turbine). These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The variable Operation and Maintenance expense for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.4.1 – In-Plant Fuel Handling Costs for Fossil Fired Units: In-Plant fuel handling costs for each fossil fired unit for the Contract Year are based on the budgeted/forecasted expenditures for in-plant fuel handling expenses charged to FERC Account 501. These budgeted expense estimates may be levelized over the major maintenance cycle of a particular unit or set of units. The estimated expenses are divided by the estimated net energy output of each unit to convert the values to dollars per megawatt-hour. The in-plant fuel handling cost for each fossil fired unit is shown on Informational Schedule No. 2 for the Contract Year.

Section 3.5 – Blended Replacement Fuel Cost: Blended replacement fuel costs are determined monthly by the AGENT and are defined as the weighted average cost, escalated for the current dispatch period, of fuel receipts for the previous month (both long-term contract and spot market receipts) and the projected fuel receipts for the current month.

Section 3.6 – Marginal Replacement Fuel Cost: Marginal replacement fuel costs for coal are determined at least monthly by the AGENT and reflect the current market price for additional coal needed at a generating facility at the time of such need. For natural gas or oil-fired units, the marginal replacement fuel costs are updated each business day based upon next day market prices.

Section 3.7 – Emission Allowance Replacement Costs: The replacement costs of emission allowances are determined at least monthly by the AGENT and reflect the current market value of such allowances.

Section 3.8 – Revisions in Methodologies: The procedures described in Sections 3.6 and 3.7 will be periodically reviewed by the AGENT and may be revised upon the approval of the Operating Committee.

ARTICLE IV

METHODOLOGY FOR DETERMINATION OF MONTHLY AMOUNT OF RESERVE SHARING CAPACITY TO BE SOLD TO OR PURCHASED FROM THE POOL

Section 4.1 – Formula for Determination of Monthly Reserve Sharing Capacity Sales/Purchases: The monthly capacity sale to or purchase from the Pool for each OPERATING COMPANY for reserve sharing purposes is determined from the following formula:

CS or CP = RS - R

Where:

CS or CP = Capacity sales to the Pool (CS) or capacity purchases from the Pool (CP) by an OPERATING COMPANY for reserve sharing purposes. A negative value indicates a sale to the Pool and a positive value indicates a purchase from the Pool.

RS = Reserve responsibility for each OPERATING COMPANY (See Section 4.1.1).

R = Reserve capacity for each OPERATING COMPANY (See Section 4.1.2).

Section 4.1.1 – Reserve Responsibility (RS): The responsibility for the reserve capacity on the integrated electric system is allocated among the OPERATING COMPANIES on the basis of peak hour load ratios for each month.

RS = L/L' x R

Where:

RS = Reserve responsibility for each OPERATING COMPANY.

L = Monthly peak hour load responsibility of each OPERATING COMPANY (See Section 4.3).

L' = Monthly peak hour load of the integrated electric system (See Section 4.3).

R = Sum of the reserve capacity for all of the OPERATING COMPANIES.

Section 4.1.2 – Reserve Capacity (R): The reserve capacity for each of the respective OPERATING COMPANIES is determined monthly by the following formula:

R = C - CR

Where:

C = Total capacity available to the OPERATING COMPANY (See Section 4.2).

CR = Total capacity required to meet reliably the OPERATING COMPANY's load responsibility.

The capacity required to meet the OPERATING COMPANY's load responsibility is determined by the following formula:

CR = LC + LCR

Where:

LC = Portion of the total capacity required to meet reliably the OPERATING COMPANY's load responsibility that is available for load service ("available portion").

LCR = Portion of the capacity required to meet reliably the OPERATING COMPANY's load responsibility that is unavailable for load service for any reason (including forced outage, partial outage or maintenance outage) during the ten (10) highest system peak hours during each month averaged over the most recent three-year period ("unavailable portion"). These unavailable portions of capacity are determined by identifying unavailability specific to each individual OPERATING COMPANY by each generation type. Individual OPERATING COMPANY unavailability factors for each type of generating capacity will be applied to their respective owned resources in determining their unavailable capacity associated with load service.

The available portion of the total capacity is determined from the following formula:

LC = RPS + DSO + Cha + Cna + Coa

Where:

RPS = Reserved contract purchases from and sales to OTHERS.

DSO = Demand side option equivalent capacity.

Cha = Total conventional hydro capacity less the unavailable portion of conventional hydro capacity.

Cna = Total nuclear capacity less the unavailable portion of nuclear capacity.

Coa = Total available pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity required to meet the remaining portion of the OPERATING COMPANY's load responsibility, calculated as: L - RPS - DSO - Cha - Cna.

The unavailable portion of the total capacity is determined from the following formula:

LCR = Chu + Cnu + (Coa/(1 - (Cou/Cot)) - Coa)

Where:

Chu = Unavailable portion of conventional hydro capacity.

Cnu = Unavailable portion of nuclear capacity.

Cou = Total unavailable pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Cot = Total pumped storage hydro, coal, combustion turbine, combined cycle, oil and gas steam, and purchased resource capacity.

Section 4.2 – Determination of Capacity Available to Each OPERATING COMPANY (C): The capacity available to each OPERATING COMPANY is determined monthly as the sum of available owned, leased, purchased or otherwise available generating units, reserved contract purchases from and sales to OTHERS, and seasonal or other power exchanges, all as established by the Operating Committee as part of the coordinated planning process. The capacity available is determined from the following formula:

$$C = Cc + Cn + Cog + Ccc + Cp + Cct + Ch + Cpsh + DSO + RPS + PRC$$

Where:

Cc	=	Coal capacity.
Cn	=	Nuclear capacity.
Cog	=	Oil and gas steam capacity.
Ccc	=	Combined cycle capacity
Cp	=	Peak Load capacity.
Cct	=	Combustion turbine capacity.
Ch	=	Conventional hydro capacity.
Cpsh	=	Pumped storage hydro capacity.
DSO	=	Demand side option equivalent capacity.
RPS	=	Reserved contract purchases from and sales to OTHERS.
PRC	=	Purchased resource capacity.

The components of the above formula shall be computed as detailed below. The capability demonstrated in accordance with such procedures shall be used in establishing the following year's capacity values. Where seasonal references are made, the seasons shall be defined as follows: Summer (June through September); Fall (October through November); Winter (December through February); and Spring (March through May).

Section 4.2.1 – Certified Rating: The production officer at each OPERATING COMPANY will certify the full load capability of each coal electric generating unit (excluding units from which Unit Power Sales and other similar bulk power sales are made), oil and gas steam electric generating unit, combined cycle unit, and combustion turbine unit. Southern Nuclear Operating Company will certify the capability of each nuclear steam electric generating unit. These certified ratings ("Full Load" ratings) shall represent the full load capability expected to be available continuously on a daily basis, under normal operating conditions, with all units at a given plant operating concurrently. Where appropriate, certified ratings shall be adjusted to reflect cogeneration and seasonal impacts. The production officer at each OPERATING COMPANY will also certify the peak load capability of generating units demonstrating such capability ("Peak Load" capability). The Peak Load capability shall represent the additional amount of generation obtained for a limited period of time by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. These unit ratings will be included in the informational filing submitted in accordance with ARTICLE VI of the IIC.

Section 4.2.2 – Coal (Cc)and Nuclear (Cn) Capacity: The Full Load rating of each coal and nuclear steam electric generating unit shall be based on the unit's capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.3 – Oil and Gas Steam Capacity (Cog): The Full Load rating of each oil and gas steam electric generating unit shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings.

Section 4.2.4 – Combined Cycle Capacity (Ccc): The Full Load rating of combined cycle generating units shall be based on the unit's demonstrated capability during hours when such unit demonstrates full output during the months of June through August, adjusted for any temporary identifiable deratings. During the other months, an adjustment will be made to the Full Load rating to reflect the unit's capability at expected ambient temperatures for such non-summer period.

Section 4.2.5 – Combustion Turbine Capacity (Cct): The Full Load rating of combustion turbine units is based on the demonstrated output of such unit and the manufacturer's base design curve rating. Combustion turbine units shall demonstrate daily sustained capability during the months of June through August, adjusted for any temporary identifiable deratings. During the fall, winter and spring, adjustments will be made to the Full Load rating to reflect the unit's capability at expected seasonal ambient temperatures.

Section 4.2.6 – Peak Load Capacity (Cp): The Peak Load capacity of demonstrating generating units shall be the additional amount of generation obtained by operating all units at a given plant concurrently and under conditions such as, but not limited to, overpressure, valves wide open and top feedwater heaters out of service. The Peak Load capacity shall be based on such unit's demonstrated capability during hours when the unit demonstrates peak load capability during the months of June through August, adjusted for temporary identifiable deratings.

Section 4.2.7 – Conventional (Ch) and Pumped Storage (Cpsh) Hydro Capacity: For purposes of the IIC, hydro capability is the average simulated generation during eight (8) consecutive hours occurring on five (5) consecutive weekdays using the average water inflows from historical data. The simulation process utilizes maximum (full) gate setting and best (most efficient) gate setting to determine the capability of the hydro facilities. The capability for the months June-August is the summer maximum gate simulated rating. For the months December-May, the capability is the winter maximum gate simulated rating. The capability of the months September-November is the summer best gate simulated rating. To the extent that an OPERATING COMPANY can demonstrate that a hydro facility can actually achieve the maximum gate rating during the fall months, the capability of such hydro facility will be the maximum gate rating.

Section 4.2.8 – Active Demand Side Options – Equivalent Capacity (DSO): The equivalent capacity of each active demand side option for each month of the calendar year is determined from the following formula:

$$DSO = [(Cv \times ICE) / (1 - (\%TL/100))] \times A$$

Where:

DSO	=	Demand side option equivalent capacity.
Cv	=	Contracted value.
ICE	=	Incremental capacity equivalent factor.
%TL	=	Six (6) percent incremental transmission losses.
A	=	Availability Factor.

The Incremental Capacity Equivalent Factor is a measure of the effect of a demand side option on generating system reliability. The Availability Factor is a measure of the probability of an active demand side option being available at the time it is needed.

Section 4.2.9 – Reserved Contract Purchases and Sales (RPS): Reserved contract purchases and sales for any month include all contracted capacity purchases from and sales to OTHERS for which there are underlying reserves.

Section 4.2.10 – Purchased Resource Capacity (PRC): Purchased resource capacity includes all purchased capacity for which an underlying generating resource is identified and may represent any type of capacity (e.g., combined cycle).

Section 4.3 – Determination of Peak Hour Load Responsibility of Each OPERATING COMPANY (L): The monthly peak hour load responsibility of each OPERATING COMPANY is determined by the following formula:

$$L = L' \times La/100$$

Where:

L' = Monthly ten (10) highest hour average load of the integrated electric system.

La = Monthly average percent contribution of each OPERATING COMPANY's ten (10) highest hour average loads to the sum of those loads for all OPERATING COMPANIES for the most recent three-year period.

Section 4.4 – Recognition of Resource Additions or Deletions: For additions or deletions of capacity resources for the coming year, an adjustment will be made in the capability resources of the appropriate OPERATING COMPANY based upon the actual date of the addition or deletion (e.g., commercial operation, retirement, purchase, or sale); provided, however, that the adjustment will not be made in a month earlier than that originally established by the Operating Committee pursuant to the coordinated planning process. If the actual date is on or before the 15th day of the month, the capacity adjustment begins in that month. If the actual date is beyond the 15th day of the month, the capacity adjustment begins in the following month.

Section 4.5 – Capacity Outside of the Coordinated Planning Process: If an OPERATING COMPANY has capacity that was not established by the Operating Committee as part of the coordinated planning process, such capacity will not be included as capacity available to the OPERATING COMPANY (pursuant to Section 4.2 of this Manual) for reserve sharing purposes ("unrecognized capacity"). Notwithstanding the foregoing, if an OPERATING COMPANY's monthly capacity/load ratio, as determined by comparing its available capacity (pursuant to Section 4.2 of this Manual) with its load responsibility (pursuant to Section 4.3 of this Manual), is less than the comparable ratio for the aggregate system (excluding the load responsibility and available capacity of the subject OPERATING COMPANY), then unrecognized capacity (up to an amount that will make these ratios comparable) will be designated as capacity available to that OPERATING COMPANY for that month.

ARTICLE V

RATE FOR MONTHLY RESERVE SHARING CAPACITY FOR EACH OPERATING COMPANY

Section 5.1 – Provision for Monthly Capacity Rate for Reserve Sharing: This article of the Manual establishes the formula rate for deriving the monthly reserve sharing capacity charge for each OPERATING COMPANY based on its most recently installed peaking facilities (or equivalent purchased resources) available for year-round operation or scheduling. OPERATING COMPANIES that have not installed or purchased such facilities or resources within the last five (5) years will utilize the weighted average rate of all the OPERATING COMPANIES that have installed or purchased such facilities or resources. In the event none of the OPERATING COMPANIES have installed or purchased such facilities or resources within the last five (5) years, the rate of the last facility or resource installed or purchased by any of them will be utilized for all OPERATING COMPANIES. The monthly reserve sharing capacity charges are utilized in the determination of payments to the Pool by the OPERATING COMPANIES purchasing capacity during the month and receipts from the Pool by the OPERATING COMPANIES selling capacity during the month. Each OPERATING COMPANY that sells reserve sharing capacity to the Pool will receive a payment based on the product of the amount of net capacity sales (CS) times that OPERATING COMPANY's monthly capacity rate. Each deficit OPERATING COMPANY will make payments to the Pool based on the product of the amount of net reserve sharing capacity purchased (CP) times the weighted average cost of such capacity sold to the Pool during the month. The monthly reserve sharing capacity rate of each OPERATING COMPANY for each month of the Contract Year is shown on Informational Schedule No. 3. Such rates will be revised in accordance with this Manual and the IIC in subsequent contract years.

Section 5.2 – Derivation of Monthly Capacity Costs of Each OPERATING COMPANY: The derivation of the monthly capacity costs of each OPERATING COMPANY, as used for purposes of the reserve sharing capacity rate, is based on one of the following: (i) the capacity cost of the most recently added peaking facility; (ii) the capacity cost of the most recent equivalent purchased resource; or (iii) the weighted system average of the capacity costs of the most recently added peaking facilities or equivalent purchased resources.

The monthly reserve sharing capacity rate of each OPERATING COMPANY for an installed peaking facility under subpart (i) will be determined by the following formula:

R1 = (I x LFCC/100/C1) x MCWF

Where:

R1 = Monthly charges for peaking

		facility ($/kW-Month).
I	=	Gross investment in peaking facility ($).
LFCC	=	16.3%, levelized fixed capacity charge.
C1	=	Peaking facility's rated production capability (kW), as determined by Section 4.2 of this Manual.
MCWF	=	Monthly Capacity Worth Factor for the applicable month.

The AGENT may periodically re-evaluate the monthly capacity worth factors based upon evaluations of system reliability. The governing MCWFs will be included in the Informational Schedules submitted in accordance with ARTICLE VI of the IIC.

For purposes of subpart (ii), the monthly reserve sharing capacity rate of each OPERATING COMPANY for an equivalent purchased resource will be the annual capacity rate ($/kW-Year) paid for such resource, multiplied by the applicable MCWF.

For purposes of subpart (iii), the monthly reserve sharing capacity rate will be the weighted system average of the costs of the most recently added peaking facilities (as determined for purposes of subpart (i)) or equivalent purchased resources (as determined for purposes of subpart (ii)), multiplied by the applicable MCWF.

<u>Section 5.3 – Monthly Reserve Sharing Capacity Rate To Be Adjusted For Production Resource Change:</u> If a peaking facility or an equivalent purchased resource of an OPERATING COMPANY is placed in commercial operation or available for scheduling by the 15th day of the month established by the Operating Committee as part of the coordinated planning process, the budgeted investment cost or annual capacity rate will be used in the determination of the monthly reserve sharing capacity rate for such OPERATING COMPANY for that and

subsequent months of the calendar year. If the facility or resource is not placed in commercial operation or available for scheduling by the 15th day of such month, the cost basis established under Section 5.2, as used to derive the monthly reserve sharing capacity rate for the previous month, will remain in effect until the month in which the facility or resource is in commercial operation or available for scheduling on or before the 15th day.

ARTICLE VI

RATE FOR TIE-LINE LOAD CONTROL AND FREQUENCY REGULATION BY HYDRO FACILITIES

Section 6.1 – Provision for Hydro Regulation Energy Losses: Because of energy losses from hydro regulation, the OPERATING COMPANIES supplying this service are deprived of hydro energy. To distribute equitably this loss of energy among the OPERATING COMPANIES in accordance with size of loads regulated and to compensate the OPERATING COMPANIES for regulating services rendered, adjustments in billing determinations are necessary. Hydro energy losses actually incurred by regulating OPERATING COMPANIES during each day are replaced by the Pool at zero cost, and the AGENT allocates such energy losses to all OPERATING COMPANIES in accordance with Peak-Period Load Ratios. Energy lost during high-flow periods is replaced during the period in which such losses occur, and energy lost from poorer efficiencies during normal and low-flow periods is replaced during the 14-hour peak period since hydro energy so lost could have been retained in storage and generated during this period.

Section 6.2 – Provision for Increases in Cost Due to Hydro Regulation: Payments are made to hydro regulating OPERATING COMPANIES for each hour of such regulation for the increase in operating and maintenance expenditures for governor mechanisms and water turbine parts, and these expenses are allocated to all OPERATING COMPANIES in accordance with Peak-

Period Load Ratios. Such payments are calculated using actual expenses incurred through the last calendar year available, adjusted to current-year dollars, for the cost of labor, engineering and supervision, and materials and supplies in the following FERC Accounts: 544-10, Generator and Exciters; 544-20, Hydraulic Turbines and Settings; 544-40, Governors and Control Apparatus; and 544-50, Powerhouse Remote Control Equipment. The basis for hourly payments is the difference in the average hourly costs for regulating plants and non-regulating plants, expressed in the following formula:

Hourly Charge = [MCW - (MCWO/HWO) x MCWH]/HOR

Where:

MCW	=	Summation of costs for regulating plants.
MCWO	=	Summation of costs for non-regulating plants.
HWO	=	Summation of hours for non-regulating plants.
MCWH	=	Summation of hours for regulating plants.
HOR	=	Summation of hours in the regulating mode for regulating plants.

The regulating OPERATING COMPANIES shall supply the AGENT an hourly statement of energy losses incurred in providing hydro regulating services. Such statement should include sufficient detail to permit review and verification by the AGENT.

Section 6.3 – Regulation by Pumped Storage Hydro Projects: It is understood that pumped storage hydro projects owned by the OPERATING COMPANIES may also be used for regulation of the integrated electric system. In such event, the hourly charge for such regulation will be the same charge derived under the formula contained in Section 6.2 hereof.

<u>Section 6.4 – Provision for Increases in Cost Due to Hydro Scheduling:</u> Because the use of hydro resources for tie-line load control and frequency regulation does not allow the hydro energy to be scheduled in the most cost effective manner, less economic gains are achieved than would have been if the hydro energy had been used to displace only the highest cost other energy sources. The difference in actual displacement costs represents the value of the lost economic opportunity by the owning OPERATING COMPANY by such use of hydro energy, or the costs of providing higher cost energy. The AGENT shall allocate such costs to all the OPERATING COMPANIES in accordance with Peak-Period Load Ratios.

[END OF MANUAL]

APPENDIX A to the SOUTHERN COMPANY SYSTEM INTERCOMPANY INTERCHANGE CONTRACT

This Appendix A ("Appendix A") to the Southern Company System Intercompany Interchange Contract ("IIC") is made and entered into as of January 1, 2019, by and between ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY, MISSISSIPPI POWER COMPANY, SOUTHERN POWER COMPANY and SOUTHERN COMPANY SERVICES, INC., being an amendment to provide for GULF POWER COMPANY's orderly withdrawal from the IIC.

Article I – Recitals

Section 1.1: WHEREAS, ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, GULF POWER COMPANY, MISSISSIPPI POWER COMPANY and SOUTHERN POWER COMPANY have for many years operated as an integrated electric utility system and have conducted their respective electric generating facilities and system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of this IIC, as most recently amended effective May 1, 2007; and

Section 1.2: WHEREAS, 700 Universe, LLC, a wholly owned subsidiary of NextEra Energy, Inc., will acquire from The Southern Company all of the common stock of GULF POWER COMPANY ("Transaction"); and

Section 1.3: WHEREAS, as a result of the Transaction, GULF POWER COMPANY will no longer be a subsidiary of The Southern Company or an affiliate of ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, MISSISSIPPI POWER COMPANY and SOUTHERN POWER COMPANY (hereinafter the "SOUTHERN OPERATING COMPANIES") after the closing of the Transaction; and

Section 1.4: WHEREAS, by separate agreement, this Agreement will be filed with the Federal Energy Regulatory Commission pursuant to Federal Power Act section 205 with a request for an effective date that is the date of the closing of the Transaction ("Effective Date"); and

Section 1.5: WHEREAS, concurrently with the closing of the Transaction, GULF POWER COMPANY will submit a notice to terminate its participation under this IIC in accordance with Section 2.3 of the IIC ("Termination Notice") and desires to withdraw from the IIC in an orderly manner; and

Section 1.6: WHEREAS, the SOUTHERN OPERATING COMPANIES wish to continue to operate under this IIC and provide for an orderly transition period whereby GULF POWER COMPANY terminates its participation under this IIC without disrupting the provision of reliable and cost-effective service to their customers or to customers in GULF POWER COMPANY's service area, as it currently exists; and

Section 1.7: WHEREAS, GULF POWER COMPANY likewise wishes to provide for an orderly transition period whereby it terminates its participation under this IIC without disrupting the provision of reliable and cost-effective service to customers in its existing service area or to the customers of the SOUTHERN OPERATING COMPANIES; and

Section 1.8: WHEREAS, the principal objectives of the IIC are set forth in Article III of the IIC ; and

Section 1.9: WHEREAS, GULF POWER COMPANY desires to continue its participation in the IIC, subject to the terms and conditions set forth herein and therein, until GULF POWER COMPANY's participation ends in accordance with this Appendix A ("Transition Period"); and

Section 1.10: WHEREAS, consistent with the foregoing, the SOUTHERN OPERATING COMPANIES, SOUTHERN COMPANY SERVICES, INC. (as the "AGENT"), and GULF POWER COMPANY (each referred to individually as a "Party" and collectively as the "Parties") agree to the following provisions that, as part of the IIC, shall govern the ongoing respective rights and responsibilities as between (i) GULF POWER COMPANY and (ii) the SOUTHERN OPERATING COMPANIES and the AGENT, under the IIC during the Transition Period.

Article II – Effective Date, Term and Assignment

Section 2.1: This Appendix A and the associated Transition Period shall become effective concurrent with the closing of the Transaction. If for any reason the Transaction does not close, then this Appendix A shall be void and of no legal effect *ab initio*.

Section 2.2: Absent early termination or limited extension as provided herein, the Transition Period shall end at 11:59 pm (prevailing Central time) on the five-year anniversary of the Termination Notice ("Scheduled Termination Date"). After the Transition Period, GULF POWER COMPANY's participation in this IIC will cease and this Appendix A shall no longer be of any force or effect. During the Transition Period, GULF POWER COMPANY shall have no further rights under Section 2.3 of the IIC.

Section 2.2.1: The Transition Period is subject to early termination in advance of the Scheduled Termination Date pursuant to Section 2.3 or Section 4.4.3 of this Appendix A.

Section 2.2.2: The Transition Period is subject to extension for a period of no more than two (2) additional years beyond the Scheduled Termination Date if GULF POWER COMPANY determines in its discretion it has not been able to establish its own balancing area, acquire the requisite balancing and related services, or establish electric generation and transmission facilities that enable GULF POWER COMPANY to provide the retail and wholesale customers in its current service area with electric services that are substantially comparable in terms of cost and reliability to those being provided to such customers through its participation in this IIC. In that event, GULF POWER COMPANY shall provide written notice to the AGENT no later than one hundred eighty (180) days prior to the Scheduled Termination Date. Any such notice shall specify the basis for the extension and the duration of the needed extension of the Transition Period, not to exceed two (2) additional years following the Scheduled Termination Date.

Section 2.3: GULF POWER COMPANY shall have the unilateral right to accelerate the Transition Period and terminate its participation under this IIC, subject to at least one hundred eighty (180) days' written notice.

Section 2.4: GULF POWER COMPANY may not assign its rights, interests or obligations under the IIC or this Appendix A, nor shall such rights, interests or obligations be extended to include obligations or resources of GULF POWER COMPANY resulting from a merger or acquisition involving another load-serving entity.

Article III – Modified Rights and Obligations of the Parties under the IIC

Section 3.1: Except as provided herein, the IIC shall remain in effect for the SOUTHERN OPERATING COMPANIES and GULF POWER COMPANY for the Transition Period, during which, and in accordance with this Appendix A, GULF POWER COMPANY shall be deemed an OPERATING COMPANY so as to effectuate the provisions of the IIC and the orderly termination of GULF POWER COMPANY's participation under this IIC. Except as expressly addressed in this Appendix A, the rights of the SOUTHERN OPERATING COMPANIES or GULF POWER COMPANY as OPERATING COMPANIES under the IIC are not limited or affected.

Section 3.2: For purposes of GULF POWER COMPANY's continued participation in the IIC during the Transition Period, the SOUTHERN OPERATING COMPANIES and the AGENT agree and commit not to treat GULF POWER COMPANY in a manner that is discriminatory (i.e., continue to apply the IIC on a comparable basis to all OPERATING COMPANIES).

Section 3.3: GULF POWER COMPANY shall no longer have a representative on the Operating Committee, but shall designate at least one official GULF POWER COMPANY contact who the AGENT shall inform of any proposed changes to the IIC or the policies, practices or procedures used in its implementation that may have a significant effect on GULF POWER COMPANY and of any other proposed actions of the Operating Committee in accordance with the Operating Committee's duties under the IIC. GULF POWER COMPANY will be given reasonable prior notice of such proposed changes or actions so that it will have an opportunity to ask questions, seek additional information, and provide feedback in advance of any Operating Committee decision or the filing of any such change. The AGENT shall cooperate in good faith to answer any such questions, provide requested additional information and facilitate GULF POWER COMPANY's feedback. Any dispute regarding a proposed action of the Operating Committee (except for a proposed change to the IIC addressed in Section 4.2 of this Appendix A) shall be resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A.

Section 3.4: GULF POWER COMPANY may make reasonable inquiries with the AGENT concerning any aspect of GULF POWER COMPANY's IIC monthly bill to ensure that the billing to GULF POWER COMPANY is accurate and determined in a manner that conforms to the IIC and the policies, practices and procedures used in its implementation, as applied on a comparable basis to all OPERATING COMPANIES. Any dispute in this regard shall be subject to Section 12.5 of the IIC and resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A.

Section 3.5: Audit Rights related to IIC Billings

Section 3.5.1: GULF POWER COMPANY shall have the right to conduct or cause to be conducted, at its own expense, a reasonable audit of the data, records and other pertinent information specifically related to the correctness of IIC billings during the Transition Period. GULF POWER COMPANY's audit rights are further subject to the following conditions:

(i) Audits may be conducted from time to time, but no more frequently than once in any rolling twelve (12) month period.

(ii) AGENT will be provided at least ten (10) business days' advance notice of any such audit, which notice shall specify the time period of the audit and describe with reasonable specificity the records, information and data to be reviewed.

(iii) No audit shall be conducted during the first week of any month.

(iv) The audit will be conducted during normal business hours and in such a manner as to minimize disruptions to the AGENT and to the SOUTHERN OPERATING COMPANIES.

(v) The time period covered by the audit may not exceed the twenty-four (24) months immediately preceding the notice and may not include any period already subject to an audit hereunder.

(vi) GULF POWER COMPANY will observe the confidentiality obligations set forth in Section 3.6 to the extent the audit encompasses any information subject to those restrictions.

Section 3.5.2: If an audit reveals, and GULF POWER COMPANY provides the relevant audit report showing, calculation errors that resulted in overcharges or underpayments to GULF POWER COMPANY: (i) GULF POWER COMPANY shall notify the AGENT; (ii) the Parties will negotiate in good faith to reach an agreement with respect to the matter; and (iii) for agreed errors, there will be a correction in accordance with Section 12.5 of the IIC (or the AGENT shall promptly cause GULF POWER COMPANY to be paid the amount of the overcharge or underpayment if there is no invoice on which to include the credit). Appropriate corrections or payments by GULF POWER COMPANY also will be made in the event the audit reveals calculation errors that resulted in undercharges or overpayments to GULF POWER COMPANY in its IIC billing.

Section 3.5.3: Any disputes arising from an audit under this Section 3.5 shall be resolved through the dispute resolution process set forth in Section 4.1 of this Appendix A and Section 12.5 of the IIC. If the arbitration upholds the results of the audit and identifies material errors resulting in overcharges or underpayments, the AGENT shall bear the reasonable costs of the audit. For purposes of this provision, a material error is one in which the effect of the erroneous charge or payment on GULF POWER COMPANY is more than ten (10) percent of the monthly average of the sum of the gross IIC billings to GULF POWER COMPANY, as measured over the ten (10) months preceding discovery.

Section 3.6: Consistent with a fundamental premise of the IIC that each OPERATING COMPANY is expected to have adequate resources to reliably serve its own obligations, GULF POWER COMPANY, through its official contact, shall provide the AGENT, not less than annually, sufficient information (e.g., generation expansion plan) to demonstrate GULF POWER COMPANY's compliance with such expectation for the duration of the Transition Period.

Section 3.7: During the Transition Period, the Parties shall abide by the following information restrictions:

Section 3.7.1: GULF POWER COMPANY may have access to information regarding the operation of its own plants or other generation resources (such as those acquired by contract) that it has committed to the Pool, but it may not have access to confidential or proprietary information of the SOUTHERN OPERATING COMPANIES, including information regarding the operation of Pool resources of the SOUTHERN OPERATING COMPANIES, except as expressly provided in Section 3.7.2.

Section 3.7.2: For confidential or proprietary information of the SOUTHERN OPERATING COMPANIES that is already in GULF POWER COMPANY's possession or for which access is unintended or unavoidable (e.g., Energy Management System ("EMS") information), GULF POWER COMPANY will not, directly or indirectly, share (and will take steps to prevent any sharing of) such information with anyone including, but not limited to, wholesale marketing function employees of GULF POWER COMPANY, any of its affiliates, and SOUTHERN POWER COMPANY.

Section 3.7.3: Information provided to the AGENT in accordance with Section 3.6 of this Appendix A: (i) may be shared with SCS personnel responsible for reviewing and aggregating the individual generation expansion plans of all Pool participants in order to present the aggregate generation expansion plan to the Operating Committee for its review and recommendation pursuant to IIC Section 3.6; (ii) may not be shared more broadly with other employees of the SOUTHERN OPERATING COMPANIES without the prior consent of GULF POWER COMPANY; and (iii) may not be shared with any wholesale marketing function employees of either SCS or the SOUTHERN OPERATING COMPANIES. In accordance with Section 5.2 of the IIC, SOUTHERN POWER COMPANY will continue to have no access to information regarding the operation of Pool resources of the other OPERATING COMPANIES, including GULF POWER COMPANY.

Section 3.8: During the Transition Period, SCS (or any replacement AGENT designated by the SOUTHERN OPERATING COMPANIES) shall continue to serve as AGENT for GULF POWER COMPANY for purposes of its participation in this IIC.

Section 3.9: For permissible longer-term wholesale transactions (i.e., outside of the period defined in Section 9.4.2 of the IIC), GULF POWER COMPANY must use its own personnel (staff) separate from the personnel (staff) that conducts similar activities on behalf of the SOUTHERN OPERATING COMPANIES.

Section 3.10: In lieu of IIC Article XI, the transmission service necessary to effectuate GULF POWER COMPANY's continued participation in this IIC during the Transition Period shall be provided in accordance with Commission-approved transmission arrangements for ALABAMA POWER COMPANY, GEORGIA POWER COMPANY, and MISSISSIPPI POWER COMPANY and for GULF POWER COMPANY, as described in the Transmission Service Coordination Agreement.

Article IV – Enforcement and Remedies

Section 4.1: GULF POWER COMPANY's exclusive rights and remedies associated with its continued participation in the IIC involve: (i) challenges to Operating Committee decisions or actions or proposed actions (as described in Section 3.3, specifically excluding decisions to file an amendment to the IIC, as addressed in Section 4.2) on grounds that the challenged action is inconsistent with the principle objectives of the IIC as set forth in Article III thereof; (ii) claims that the AGENT is not applying the IIC (including underlying policies, practices or procedures used in its implementation) on a comparable basis to all OPERATING COMPANIES (as described in Sections 3.2 and 3.4); (iii) claims that the AGENT is not properly billing under the IIC; and (iv) claims that the SOUTHERN OPERATING COMPANIES are in material breach of their obligations under the IIC. With respect to any such matters, the following dispute resolution procedures shall govern:

Section 4.1.1: GULF POWER COMPANY must first discuss any questions, concerns or objections ("Issue") with the AGENT. In connection with such discussions, the AGENT must be afforded a reasonable amount of time to understand and investigate the Issue, including any needed data collection. Unless otherwise agreed, this initial step with the AGENT shall not extend beyond thirty (30) days to address the Issue.

Section 4.1.2: If the Issue is not addressed by the AGENT to GULF POWER COMPANY's satisfaction within thirty (30) days, then GULF POWER COMPANY shall provide written notice to the AGENT describing the Issue and why the AGENT's response has been deemed unsatisfactory by GULF POWER COMPANY. Within ten (10) days after the delivery of the notice, a senior official of the SOUTHERN OPERATING COMPANIES and of GULF POWER COMPANY, each with authority to negotiate and resolve the Issue, shall meet, either in person or by telephonic conference, in an effort to resolve the Issue through mutual agreement. A representative of the AGENT may participate in this meeting. If the Issue has not been resolved within ten (10) days after the meeting of senior officials, then GULF POWER COMPANY may invoke arbitration in accordance with Section 4.1.3.

Section 4.1.3: In the event resolution is not obtained pursuant to Section 4.1.2, the Parties agree that the dispute shall be resolved through binding arbitration. The Parties will cooperate in the arbitration process (including scheduling) so that the Issue will be resolved as quickly as practicable, with due regard for its nature and complexity. Except as provided herein or otherwise agreed by the Parties, the arbitration shall be administered by the American Arbitration Association in accordance with its Commercial Arbitration Rules.

(i) The arbitration panel shall comprise three (3) members, with each Party selecting one member and the two members so named selecting the third member.

(ii) All members must have at least fifteen (15) years of experience in the areas of electric energy and power system operations.

(iii) All members must be neutral, act impartially, and be free from any conflict of interest (financial or otherwise, with no prior or present business or personal relationship with the Parties).

(iv) After selection, the members shall have no ex-parte communications with either Party.

(v) The arbitration and all related information shall be private and confidential, with no disclosure except as required by law or by agreement of the Parties.

(vi) The arbitration shall be held in Orlando, Florida.

(vii) The Party invoking arbitration bears the burden of proof.

(viii) Each Party shall bear its own internal costs (e.g., employees, attorneys and consultants), but the losing Party shall also be responsible for costs otherwise associated with the arbitration process.

Section 4.2: In the event GULF POWER COMPANY, having been informed of a proposed change to the IIC in accordance with Section 3.3, remains opposed to such proposed change, its opposition shall not be the subject of dispute resolution under Section 4.1 and shall not prohibit the AGENT from filing for FERC acceptance of the proposed change. However, in response to that filing, GULF POWER COMPANY may raise its objections with FERC and shall not be prejudiced by the fact that SCS is otherwise its AGENT for purposes of the IIC. Conversely, the AGENT and the SOUTHERN OPERATING COMPANIES shall not be limited in their ability to support the proposed revision as just and reasonable.

Section 4.3: The Parties expressly acknowledge and agree that GULF POWER COMPANY's sole and exclusive remedy for any Issue raised under Section 4.1 is pursuant to the provisions set forth therein. Notwithstanding the foregoing, and without any prejudice to or waiver thereof, in the event GULF POWER COMPANY attempts to bring a proceeding before the FERC regarding any provision of the IIC (including this Appendix A), or any issues related to application or implementation, and such proceeding is not otherwise dismissed, the standard of review to be applied in any such proceeding shall be the most stringent standard permissible under applicable law, as set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956); *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008), and refined in *NRG Power Marketing v. Maine Public Utilities Commission*, 130 S. Ct. 693, 700 (2010).

Section 4.4: In the event the AGENT, on behalf of the SOUTHERN OPERATING COMPANIES, believes there has been a material breach by GULF POWER COMPANY to comply with its obligations under the IIC or this Appendix A, the following procedures shall apply:

Section 4.4.1: The AGENT shall notify GULF POWER COMPANY of any concerns regarding potential alleged breaches. GULF POWER COMPANY shall be afforded a reasonable amount of time to understand and investigate the concern and, unless otherwise agreed, shall have up to thirty (30) days to address any such concerns.

Section 4.4.2: If such concerns are not addressed by GULF POWER COMPANY to the AGENT's satisfaction, the AGENT shall so notify GULF POWER COMPANY in writing, describing the alleged breach and why GULF POWER COMPANY'S response has been deemed unsatisfactory by the AGENT. Within ten (10) days after the delivery of the notice, a senior official of the AGENT and of GULF POWER COMPANY, each with authority to negotiate and resolve the concern, shall meet, either in person or by telephonic conference, in an effort to resolve the concern through mutual agreement. If the concern has not been resolved within ten (10) days after the meeting of senior officials, then the AGENT may invoke arbitration in accordance with Section 4.4.3.

Section 4.4.3: In the event the AGENT invokes arbitration, the procedures set forth in Section 4.1.3 shall apply. In the event the arbitration concludes that GULF POWER COMPANY is in material breach, then GULF POWER COMPANY shall have thirty (30) days to cure such failure, which cure must be to the AGENT's reasonable satisfaction. In the event GULF POWER COMPANY elects not to cure, or fails to cure, the AGENT may give one hundred and eighty (180) days' written notice to terminate the Transition Period and GULF POWER COMPANY shall thereafter have no further participation under this IIC.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF, the Parties hereto have caused this instrument to be signed by their duly authorized representatives, which signatures may be set forth on separate counterpart pages.

GULF POWER COMPANY

By: Michael Smith
Its Gen. Mgr. - Gulf

ALABAMA POWER COMPANY

By:
Its SVP/SPO - West

GEORGIA POWER COMPANY

By:
Its SVP & SPO - East

MISSISSIPPI POWER COMPANY

By:
Its SVP/SPO - West

SOUTHERN POWER COMPANY

By:
Its SVP/SPO

SOUTHERN COMPANY SERVICES, INC.

By:
Its VP Commercial Operations

[END OF APPENDIX A]

Arkansas Public Service Commission Approves Retirement of Dolet Hills coal plant, signaling cleaner air for communities in Louisiana

Marks Sierra Club's Beyond Coal Campaign 300th coal plant retirement

Wednesday, January 8, 2020

Contact:
Vanessa Ramos, Vanessa.Ramos@sierraclub.org, (512) 586-1853
Cherelle Blazer, cherelle.blazer@sierraclub.org, (214) 604-0425
Glen Hooks, glen.hooks@sierraclub.org, 501-744-2674

ARKANSAS - Today, Southwestern Electric Power Company (SWEPCO) announced the retirement of the Dolet Hills coal-fired power plant as part of a settlement with Sierra Club in the Arkansas Public Service Commission. Communities in Shreveport and Northeastern Louisiana have long been affected by air pollution from Dolet Hills, while communities in Arkansas have had to foot the bill to keep the expensive and aging coal plant in operation.

Dolet Hills, which is co-owned by Cleco Corporate Holdings LLC and AEP Southwestern Electric Power Company (SWEPCO), is the most expensive coal plant in Louisiana, and emits more Carbon Dioxide, Sulfur Dioxide, and Nitrogen Oxide per unit of electricity than all other power plants in the state. Sierra Club's analysis showed that permanently retiring Dolet Hills will save its customers more than $60 million a year in their electric bills, that the Dolet Hills power plant consistently costs more to operate than it generates in revenue, and that the plant should be retired as soon as possible. The analysis also showed that replacing Dolet Hills with more affordable, cleaner wind and solar energy generation would create hundreds of sustainable jobs for Louisiana.

Aging coal plants are increasingly obsolete and uneconomic. Despite President Trump promising the resurgence of coal, since he was elected Sierra Club's Beyond Coal campaign has secured the retirement of 62 coal plants across the United States. In Louisiana, Texas and Arkansas the prices of utility-scale wind and solar power are now less than the price of buying fuel for SWEPCO's coal plants. SWEPCO can start relying on more solar and wind power, and save customers money on their monthly electric bills at the same time.

Despite clean energy's growth in Louisiana and neighboring states, SWEPCO energy generation continues to be 83% coal. Pollution from the Dolet Hills coal plant has long affected communities across Louisiana, especially in Mansfield,whose population is 76% African American and in Shreveport whose population is 57% African American. Due to Dolet Hills' high pollution rates and proximity to minority populations, the plant received a "D" grade from the NAACP's "Coal Blooded" analysis.

The phase-out of SWEPCO's Dolet Hills coal plant marks Sierra Club's Beyond Coal Campaign's 300th coal plant retirement. The Beyond Coal campaign credits the coal plant retirement movement with the annual prevention of 8,001 premature deaths, 12,345 heart attacks, 131,713 asthma attacks, and $3.8 billion in healthcare costs.

In response, Cherelle Blazer, Senior Campaign Representative for Sierra Club's Beyond Coal campaign in Louisiana and Arkansas, released the following statement:

"The retirement of Dolet Hills is a win for ratepayers, public health and the environment. This is a golden opportunity for investment in Louisiana and Arkansas with more cost-effective clean energy capital projects like building solar and wind capacity. Sierra Club supports a just transition for affected workers and front line communities who have suffered from dirty coal pollution for over 40 years."

In response, Glen Hooks, Director of the Sierra Club's Arkansas Chapter, said the following:

"Clean solar and wind energy are now both incredibly affordable and more efficient than ever before. The Arkansas Sierra Club is proud to support a settlement that keeps Arkansas ratepayers from propping up an inefficient out-of-state coal plant. This settlement saves Arkansas ratepayers money, moves us away from dirty coal, and will improve air quality in the Natural State."

About the Sierra Club

The Sierra Club is America's largest and most influential grassroots environmental organization, with more than 3.5 million members and supporters. In addition to protecting every person's right to get outdoors and access the healing power of nature, the Sierra Club works to promote clean energy, safeguard the health of our communities, protect wildlife, and preserve our remaining wild places through grassroots activism, public education, lobbying, and legal action. For more information, visit www.sierraclub.org.

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PSC DOCKET NO 42
APG 's EX. NO 42
WITNESS Wilson-Cross

Table 2 of Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014 and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	450 kg of CO_2 per MWh of gross energy output (1,000 lb CO_2/MWh); or 470 kilograms (kg) of CO_2 per megawatt-hour (MWh) of net energy output (1,030 lb/MWh).
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2 per gigajoule (GJ) of heat input (120 lb CO_2/MMBtu).
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis	50 kg CO_2/GJ of heat input (120 lb/MMBtu) to 69 kg CO_2/GJ of heat input (160 lb/MMBtu) as determined by the procedures in §60.5525.

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Federal Register
Vol. 82, No. 61
Friday, March 31, 2017

Presidential Documents

A.P.S.C. DOCKET NO 37453
APCo 'S EX. NO. 43
WITNESS Wilson-Gross

Title 3—

The President

Executive Order 13783 of March 28, 2017

Promoting Energy Independence and Economic Growth

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1. *Policy.* (a) It is in the national interest to promote clean and safe development of our Nation's vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation. Moreover, the prudent development of these natural resources is essential to ensuring the Nation's geopolitical security.

(b) It is further in the national interest to ensure that the Nation's electricity is affordable, reliable, safe, secure, and clean, and that it can be produced from coal, natural gas, nuclear material, flowing water, and other domestic sources, including renewable sources.

(c) Accordingly, it is the policy of the United States that executive departments and agencies (agencies) immediately review existing regulations that potentially burden the development or use of domestically produced energy resources and appropriately suspend, revise, or rescind those that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with the law.

(d) It further is the policy of the United States that, to the extent permitted by law, all agencies should take appropriate actions to promote clean air and clean water for the American people, while also respecting the proper roles of the Congress and the States concerning these matters in our constitutional republic.

(e) It is also the policy of the United States that necessary and appropriate environmental regulations comply with the law, are of greater benefit than cost, when permissible, achieve environmental improvements for the American people, and are developed through transparent processes that employ the best available peer-reviewed science and economics.

Sec. 2. *Immediate Review of All Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources.* (a) The heads of agencies shall review all existing regulations, orders, guidance documents, policies, and any other similar agency actions (collectively, agency actions) that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources. Such review shall not include agency actions that are mandated by law, necessary for the public interest, and consistent with the policy set forth in section 1 of this order.

(b) For purposes of this order, "burden" means to unnecessarily obstruct, delay, curtail, or otherwise impose significant costs on the siting, permitting, production, utilization, transmission, or delivery of energy resources.

(c) Within 45 days of the date of this order, the head of each agency with agency actions described in subsection (a) of this section shall develop and submit to the Director of the Office of Management and Budget (OMB Director) a plan to carry out the review required by subsection (a) of this section. The plans shall also be sent to the Vice President, the Assistant to the President for Economic Policy, the Assistant to the President for Domestic Policy, and the Chair of the Council on Environmental Quality. The head of any agency who determines that such agency does not have agency actions described in subsection (a) of this section shall submit to the OMB Director a written statement to that effect and, absent a determination by the OMB Director that such agency does have agency actions described in subsection (a) of this section, shall have no further responsibilities under this section.

(d) Within 120 days of the date of this order, the head of each agency shall submit a draft final report detailing the agency actions described in subsection (a) of this section to the Vice President, the OMB Director, the Assistant to the President for Economic Policy, the Assistant to the President for Domestic Policy, and the Chair of the Council on Environmental Quality. The report shall include specific recommendations that, to the extent permitted by law, could alleviate or eliminate aspects of agency actions that burden domestic energy production.

(e) The report shall be finalized within 180 days of the date of this order, unless the OMB Director, in consultation with the other officials who receive the draft final reports, extends that deadline.

(f) The OMB Director, in consultation with the Assistant to the President for Economic Policy, shall be responsible for coordinating the recommended actions included in the agency final reports within the Executive Office of the President.

(g) With respect to any agency action for which specific recommendations are made in a final report pursuant to subsection (e) of this section, the head of the relevant agency shall, as soon as practicable, suspend, revise, or rescind, or publish for notice and comment proposed rules suspending, revising, or rescinding, those actions, as appropriate and consistent with law. Agencies shall endeavor to coordinate such regulatory reforms with their activities undertaken in compliance with Executive Order 13771 of January 30, 2017 (Reducing Regulation and Controlling Regulatory Costs).

Sec. 3. *Rescission of Certain Energy and Climate-Related Presidential and Regulatory Actions.* (a) The following Presidential actions are hereby revoked:

(i) Executive Order 13653 of November 1, 2013 (Preparing the United States for the Impacts of Climate Change);

(ii) The Presidential Memorandum of June 25, 2013 (Power Sector Carbon Pollution Standards);

(iii) The Presidential Memorandum of November 3, 2015 (Mitigating Impacts on Natural Resources from Development and Encouraging Related Private Investment); and

(iv) The Presidential Memorandum of September 21, 2016 (Climate Change and National Security).

(b) The following reports shall be rescinded:

(i) The Report of the Executive Office of the President of June 2013 (The President's Climate Action Plan); and

(ii) The Report of the Executive Office of the President of March 2014 (Climate Action Plan Strategy to Reduce Methane Emissions).

(c) The Council on Environmental Quality shall rescind its final guidance entitled "Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews," which is referred to in "Notice of Availability," 81 *Fed. Reg.* 51866 (August 5, 2016).

(d) The heads of all agencies shall identify existing agency actions related to or arising from the Presidential actions listed in subsection (a) of this section, the reports listed in subsection (b) of this section, or the final guidance listed in subsection (c) of this section. Each agency shall, as soon as practicable, suspend, revise, or rescind, or publish for notice and comment proposed rules suspending, revising, or rescinding any such actions, as appropriate and consistent with law and with the policies set forth in section 1 of this order.

Sec. 4. *Review of the Environmental Protection Agency's "Clean Power Plan" and Related Rules and Agency Actions.* (a) The Administrator of the Environmental Protection Agency (Administrator) shall immediately take all steps necessary to review the final rules set forth in subsections (b)(i) and (b)(ii) of this section, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules. In addition, the Administrator shall immediately take all steps necessary to review the proposed rule set forth in subsection (b)(iii) of this section, and, if appropriate, shall, as soon as practicable, determine whether to revise or withdraw the proposed rule.

(b) This section applies to the following final or proposed rules:

(i) The final rule entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 *Fed. Reg.* 64661 (October 23, 2015) (Clean Power Plan);

(ii) The final rule entitled "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," 80 *Fed. Reg.* 64509 (October 23, 2015); and

(iii) The proposed rule entitled "Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations; Proposed Rule," 80 *Fed. Reg.* 64966 (October 23, 2015).

(c) The Administrator shall review and, if appropriate, as soon as practicable, take lawful action to suspend, revise, or rescind, as appropriate and consistent with law, the "Legal Memorandum Accompanying Clean Power Plan for Certain Issues," which was published in conjunction with the Clean Power Plan.

(d) The Administrator shall promptly notify the Attorney General of any actions taken by the Administrator pursuant to this order related to the rules identified in subsection (b) of this section so that the Attorney General may, as appropriate, provide notice of this order and any such action to any court with jurisdiction over pending litigation related to those rules, and may, in his discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, pending the completion of the administrative actions described in subsection (a) of this section.

Sec. 5. *Review of Estimates of the Social Cost of Carbon, Nitrous Oxide, and Methane for Regulatory Impact Analysis.* (a) In order to ensure sound regulatory decision making, it is essential that agencies use estimates of costs and benefits in their regulatory analyses that are based on the best available science and economics.

(b) The Interagency Working Group on Social Cost of Greenhouse Gases (IWG), which was convened by the Council of Economic Advisers and the OMB Director, shall be disbanded, and the following documents issued by the IWG shall be withdrawn as no longer representative of governmental policy:

(i) Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2010);

(ii) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (May 2013);

(iii) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (November 2013);

(iv) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (July 2015);

(v) Addendum to the Technical Support Document for Social Cost of Carbon: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016); and

(vi) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (August 2016).

(c) Effective immediately, when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates, agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A–4 of September 17, 2003 (Regulatory Analysis), which was issued after peer review and public comment and has been widely accepted for more than a decade as embodying the best practices for conducting regulatory cost-benefit analysis.

Sec. 6. *Federal Land Coal Leasing Moratorium.* The Secretary of the Interior shall take all steps necessary and appropriate to amend or withdraw Secretary's Order 3338 dated January 15, 2016 (Discretionary Programmatic Environmental Impact Statement (PEIS) to Modernize the Federal Coal Program), and to lift any and all moratoria on Federal land coal leasing activities related to Order 3338. The Secretary shall commence Federal coal leasing activities consistent with all applicable laws and regulations.

Sec. 7. *Review of Regulations Related to United States Oil and Gas Development.* (a) The Administrator shall review the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," 81 *Fed. Reg.* 35824 (June 3, 2016), and any rules and guidance issued pursuant to it, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules.

(b) The Secretary of the Interior shall review the following final rules, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules:

(i) The final rule entitled "Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands," 80 *Fed. Reg.* 16128 (March 26, 2015);

(ii) The final rule entitled "General Provisions and Non-Federal Oil and Gas Rights," 81 *Fed. Reg.* 77972 (November 4, 2016);

(iii) The final rule entitled "Management of Non-Federal Oil and Gas Rights," 81 *Fed. Reg.* 79948 (November 14, 2016); and

(iv) The final rule entitled "Waste Prevention, Production Subject to Royalties, and Resource Conservation," 81 *Fed. Reg.* 83008 (November 18, 2016).

(c) The Administrator or the Secretary of the Interior, as applicable, shall promptly notify the Attorney General of any actions taken by them related to the rules identified in subsections (a) and (b) of this section so that the Attorney General may, as appropriate, provide notice of this order and any such action to any court with jurisdiction over pending litigation related to those rules, and may, in his discretion, request that the court stay the litigation or otherwise delay further litigation, or seek other appropriate relief consistent with this order, until the completion of the administrative actions described in subsections (a) and (b) of this section.

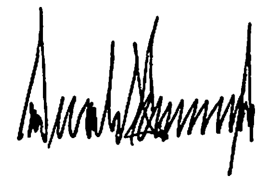
Sec. 8. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
March 28, 2017.

[FR Doc. 2017–06576
Filed 3–30–17; 11:15 am]
Billing code 3295–F7–P

32953

A.P.S.C. DOCKET NO 44

APW 'S EX. NO. 44

Wilson-Cross

Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

EPA-452/R-19-003
June 2019

Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impact Division
Research Triangle Park, NC

CHAPTER 4: ESTIMATED CLIMATE BENEFITS AND HUMAN HEALTH CO-BENEFITS

4.1 Introduction

Implementing the final rule is expected to decrease emissions of carbon dioxide (CO_2) and certain pollutants in the atmosphere that adversely affect human health as compared to the baseline. Pollutant emissions include directly emitted fine particles ($PM_{2.5}$; particles with an aerodynamic diameter of 2.5 microns or smaller), sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and mercury (Hg). SO_2 and NO_X are each a precursor to ambient $PM_{2.5}$, and NO_X emissions are also a precursor in the formation of ambient ground-level ozone.

This chapter describes the methods used to estimate the domestic climate benefits associated with the decrease in CO_2 emissions and domestic health benefits associated with the decrease in $PM_{2.5}$ and ground-level ozone. The EPA refers to the climate benefits as "targeted pollutant benefits" as they reflect the direct benefits of reducing CO_2, and to the ancillary health benefits derived from reductions in emissions other than CO_2 as "co-benefits" as they are not direct benefits from reducing the targeted pollutant. Data, resource, and methodological limitations prevent the EPA from estimating all domestic climate benefits and health and environmental co-benefits, including those from health effects from direct exposure to SO_2, NO_2, and hazardous air pollutants (HAP) including Hg, and ecosystem effects and visibility impairment. We discuss these unquantified effects in Section 4.7.

4.2 Climate Change Impacts

In 2009, the EPA Administrator found that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare.[1] It is these adverse impacts that necessitate the EPA regulation of GHGs from EGU sources. Since 2009, other science assessments suggest accelerating trends.[2]

[1] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("Endangerment Finding").
[2] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: Climate Change Impacts in the United States: The Third National Climate Assessment. U.S. Global Change Research Program, 841 pp.

4.3 Approach to Estimating Climate Benefits from CO_2

We estimate the climate benefits from this final rulemaking using a measure of the domestic social cost of carbon (SC-CO_2). The SC-CO_2 is a metric that estimates the monetary value of projected impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions). The SC-CO_2 estimates used in this RIA focus on the projected impacts of climate change that are anticipated to directly occur within U.S. borders.

The SC-CO_2 estimates presented in this RIA are interim values developed under E.O. 13783 for use in regulatory analyses until an improved estimate of the impacts of climate change to the U.S. can be developed based on the best available science and economics. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) used in the 2015 CPP RIA for describing the global social cost of greenhouse gas estimates developed under the prior Administration as no longer representative of government policy.

Regarding the two analytical considerations highlighted in E.O. 13783 – how best to consider domestic versus international impacts and appropriate discount rates – current guidance in OMB Circular A-4 is as follows. Circular A-4 states that analysis of economically significant proposed and final regulations "should focus on benefits and costs that accrue to citizens and residents of the United States." We follow this guidance by adopting a domestic perspective in our central analysis. Regarding discount rates, Circular A-4 states that regulatory analyses

doi:10.7930/J0Z31WJ2; and USGCRP, 2017: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp., doi: 10.7930/J0J964J6.

"should provide estimates of net benefits using both 3 percent and 7 percent." The 7 percent rate is intended to represent the average before-tax rate of return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private consumption directly. The EPA follows this guidance below by presenting estimates based on both 3 and 7 percent discount rates in the main analysis. See Chapter 7 for a discussion the modeling steps involved in estimating the domestic SC-CO_2 estimates based on these discount rates. These SC-CO_2 estimates developed under E.O. 13783 presented below will be used in regulatory analysis until more comprehensive domestic estimates can be developed, which would take into consideration recent recommendations from the National Academies of Sciences, Engineering, and Medicine[3] to further update the current methodology to ensure that the SC-CO_2 estimates reflect the best available science.

Table 4-1 presents the average domestic SC-CO_2 estimate across all of the integrated assessment model runs used to estimate the SC-CO_2 for each discount rate for the years 2015 to 2050.[4] As with the global SC-CO_2 estimates, the domestic SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to gross GDP. For emissions occurring in the year 2030, the two domestic SC-CO_2 estimates are $1 and $8 per metric ton of CO_2 emissions (2016$), using a 7 and 3 percent discount rate, respectively.

[3] See National Academies of Sciences, Engineering, and Medicine, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, Washington, D.C., January 2017. http://www.nap.edu/catalog/24651/valuing-climate-changes-updating-estimation-of-the-social-cost-of

[4] The SC-CO_2 estimates rely on an ensemble of three integrated assessment models (IAMs): Dynamic Integrated Climate and Economy (DICE) 2010; Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8; and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009. See Chapter 7 for an overview of the modeling methodology.

Table 4-1 Interim Domestic Social Cost of CO_2, 2015-2050 (in 2016\$ per metric ton)[a]

Year	Discount Rate and Statistic	
	3% Average	7% Average
2015	\$6	\$1
2020	7	1
2025	7	1
2030	8	1
2035	9	2
2040	9	2
2045	10	2
2050	11	2

[a] These SC-CO_2 values are stated in \$/metric ton CO_2 and rounded to the nearest dollar. These values may be converted to \$/short ton using the conversion factor 0.90718474 metric tons per short ton for application to the short ton CO_2 emission impacts provided in this rulemaking. Such a conversion does not change the underlying methodology, nor does it change the meaning of the SC-CO_2 estimates. For both metric and short tons denominated SC-CO_2 estimates, the estimates vary depending on the year of CO_2 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

Table 4-2 reports the domestic climate benefits in the three analysis years (2025, 2030, 2035) for the illustrative policy scenario, compared to the baseline.

Table 4-2 Estimated Domestic Climate Benefits, Relative to Baseline (millions of 2016\$)[a]

	3% Discount Rate	7% Discount Rate
2025	81	13
2030	81	14
2035	72	13

[a] Values rounded to two significant figures. The SC-CO_2 values are dollar-year and emissions-year specific. SC-CO_2 values represent only a partial accounting of climate impacts.

The limitations and uncertainties associated with the SC-CO_2 analysis, which were discussed at length in the 2015 CPP RIA, likewise apply to the domestic SC-CO_2 estimates presented in this RIA. Some uncertainties are captured within the analysis, as discussed in detail in Chapter 7, while other areas of uncertainty have not yet been quantified in a way that can be modeled. For example, limitations include the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and inter-sectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. The science incorporated into these models understandably lags behind the most recent research, and the limited amount of research linking climate impacts to economic damages makes this comprehensive global modeling exercise even more difficult. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CO_2 estimates. In accordance with guidance in OMB Circular A-4 on the treatment of uncertainty, Chapter 7 provides a detailed discussion of the ways in which the modeling underlying the development of the SC-CO_2 estimates used in this RIA addressed quantified sources of uncertainty and presents a sensitivity analysis to show consideration of the uncertainty surrounding discount rates over long time horizons.

Recognizing the limitations and uncertainties associated with estimating the SC-CO_2, the research community has continued to explore opportunities to improve SC-CO_2 estimates. Notably, the National Academies of Sciences, Engineering, and Medicine conducted a multi-discipline, multi-year assessment to examine potential approaches, along with their relative merits and challenges, for a comprehensive update to the current methodology. The task was to ensure that the SC-CO_2 estimates that are used in Federal analyses reflect the best available science, focusing on issues related to the choice of models and damage functions, climate science modeling assumptions, socioeconomic and emissions scenarios, presentation of uncertainty, and discounting. In January 2017, the Academies released their final report, Assessing Approaches to Updating the Social Cost of Carbon, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017).[5]

The Academies' 2017 report also discussed the challenges in developing domestic SC-CO_2 estimates, noting that current integrated assessment models do not model all relevant regional interactions – i.e., how climate change impacts in other regions of the world could affect the United States, through pathways such as global migration, economic destabilization, and political destabilization. The Academies concluded that it "is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States. More thoroughly estimating a domestic SC-CO_2 would therefore need to consider the potential implications of climate impacts on, and actions by,

[5] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* National Academies Press. Washington, DC Available at <https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of> Accessed May 30, 2017.

other countries, which also have impacts on the United States." (National Academies 2017, pg. 12-13).

In addition to requiring reporting of impacts at a domestic level, Circular A-4 states that when an agency "evaluate[s] a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (page 15). This guidance is relevant to the valuation of damages from CO_2 and other GHGs, given that GHGs contribute to damages around the world independent of the country in which they are emitted. Therefore, in accordance with this guidance in OMB Circular A-4, Chapter 7 presents the global climate benefits from this final rulemaking using global SC-CO_2 estimates based on both 3 and 7 percent discount rates. Note the EPA did not quantitatively project the full impact of ACE on international trade and the location of production, so it is not possible to present analogous estimates of international costs resulting from the final action. However, to the extent that the IPM analysis endogenously models international electricity and natural gas trade, and to the extent that affected firms have some foreign ownership, some of the costs accruing to entities outside U.S. borders is captured in the compliance costs presented in this RIA. See Chapter 5 for more discussion of challenges involved in estimating the ultimate distribution of compliance costs.

4.4 Approach to Estimating Human Health Ancillary Co-Benefits

As noted above, this final rule is designed to affect emissions of CO_2 from the EGU sector but will also influence the level of other pollutants emitted in the atmosphere that adversely affect human health; these include directly emitted $PM_{2.5}$, as well as SO_2 and NO_X, which are both precursors to ambient $PM_{2.5}$. NO_X emissions are also a precursor to ambient ground-level ozone. The EGU emissions associated with the baseline and the illustrative policy scenario are shown in Table 4-3. The change in emissions between the baseline and the illustrative policy scenario will in turn alter the ambient concentrations, population exposure and human health impacts associated with $PM_{2.5}$ and ozone. Finally, ambient concentrations of both SO_2 and NO_X pose health risks independent of $PM_{2.5}$ and ozone, though we do not quantify these impacts in this analysis (U.S. EPA 2016b, 2017).

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OPINION

Angry US landowners are killing off renewable energy projects

By Robert Bryce

March 7, 2020 I 1:03pm

Wind-energy projects like the Groton Wind Farm in New Hampshire require huge amounts of land -- and rural communities are not all happy about it.
AerialPhotoNH

There's an old saw in the trash business that says, "everybody wants their trash picked up but nobody wants it put down."

That's not a perfect analogy for what's happening with renewable-energy projects in New York and New England but the sentiment behind it is familiar. A recent Gallup poll found that 73 percent of Americans favor increased use of wind and solar energy. But in New York and the Northeast, adding large increments of new renewable capacity is getting increasingly difficult due to growing local opposition. Land-use conflicts are also hindering high-voltage transmission projects.

Last May, Cambria in upstate New York rejected a proposed 100-megawatt solar project because it violated the town's zoning laws, and another upstate town, Duanesburg, recently imposed a six-month moratorium on new solar projects.

Last July, the New Hampshire Supreme Court voted unanimously to uphold the state's rejection of the proposed Northern Pass transmission line, a 192-mile-long project designed to bring hydropower from Canada to New England.

In January, the company backing Dairy Air Wind, the only remaining wind-energy project being developed in Vermont, announced it was pulling the plug on the single-turbine facility due to a "political environment that is hostile to wind energy."

These land-use conflicts aren't limited to the northeast. Last year, some 200 protesters were arrested while attempting to stop construction of a wind project on the island of Oahu. In Germany, the expansion of wind and transmission projects has been almost completely stopped due to widespread rural opposition.

Indian Point Energy Center in Buchanan, New York, will close its doors in April 2021, but it produces a lot more power in a smaller space than renewable energy projects.
Kevin P. Coughlin/FlyingDogPhoto

The conflict stems from the vacant-land myth: the notion that there's plenty of unused land out there in flyover country that's ready and waiting to be covered with wind turbines, solar panels, power lines and other infrastructure.

The truth is that growing numbers of rural and suburban landowners are resisting these types of projects. They don't want to endure the noise and shadow flicker produced by 500- or 600-foot-high wind turbines. Nor do they want miles of transmission lines built through their towns, so they are fighting to protect their property values and views.

A fundamental constraint on the growth of renewables is they require lots of land to produce significant flows of energy. And as more large-scale renewable projects are proposed, more land, and more people, are being affected.

Nuclear power, meanwhile, produces a lot more energy in a small amount of space, evidenced by the Indian Point Energy Center in Buchanan, which will be prematurely shuttered by April 2021. Indian Point produces about 16 terawatt-hours of electricity per year from a footprint of one square kilometer.

The conclusion is clear: Dense cities need dense sources of power generation.

Replacing that output with wind energy would require installing hundreds of turbines over some 1,335 square kilometers (515 square miles) of territory. Thus, from a land-use or ocean-use perspective, wind energy requires about 1,300 times as much territory to produce the same amount of energy as is now being produced by Indian Point.

The Brattle Group recently estimated that New England states will need to double electricity production to achieve an 80 percent cut in emissions by 2050. Achieving that cut with renewables will require adding as much as 7 gigawatts of new capacity every year between 2021 and 2050, which, the firm says, amounts to "four to eight times as much renewable capacity every year as currently projected for the next decade."

But given the ongoing land-use conflicts, adding that much new renewable capacity appears to be little more than wishful thinking.

The conclusion is clear: Dense cities need dense sources of power generation. Sure, renewables will grow. But land-use conflicts are already hindering their expansion. If New York and New England want to reduce emissions and keep the lights on, they will need energy sources that are low-carbon, scalable and affordable. That means using more natural gas and nuclear. It also means rather than closing nuclear plants like the Indian Point Energy Center, policymakers in New York and other states should be fighting to keep them open.

Robert Bryce's sixth book, "A Question of Power: Electricity and the Wealth of Nations" (PublicAffairs) is out Tuesday.

FILED UNDER **GREEN ENERGY, RENEWABLE ENERGY**

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All Prices | OPEC Blends | Canadian Blends | U.S Blends

WTI CRUDE	41.28	-4.62	-10.07%
BRENT CRUDE	45.27	-4.72	-9.44%
NATURAL GAS	1.708	-0.064	-3.61%
MARS US	41.98	-4.72	-10.11%
LOUISIANA LIGHT	48.95	-4.13	-7.78%
BONNY LIGHT	46.33	-5.61	-10.80%
MEXICAN BASKET	40.32	-1.05	-2.54%
NATURAL GAS	1.708	-0.064	-3.61%

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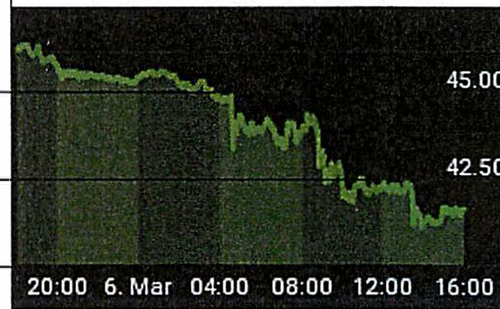
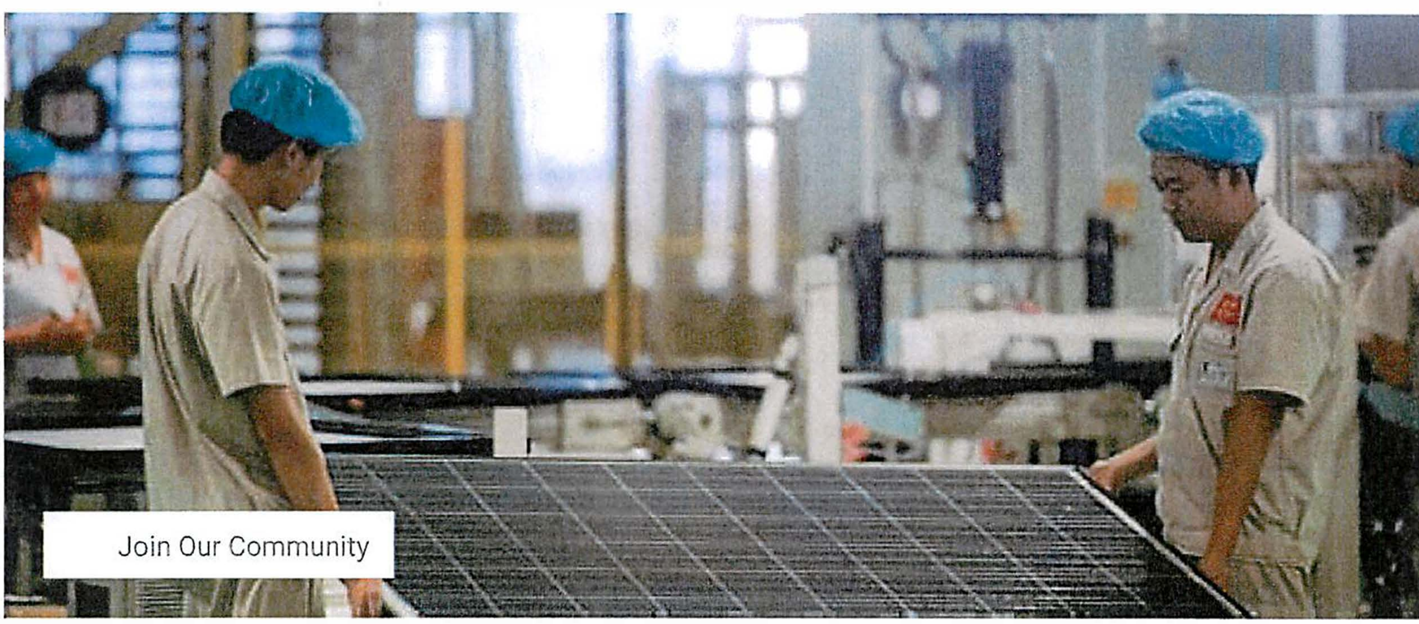


Di:

The Solar Sector Is Suffering From Coronavirus Contagion

By Tsvetana Paraskova - Feb 19, 2020, 5:00 PM CST



While analysts and international agencies are already assessing the fallout from the coronavirus outbreak on global oil demand, the damage to the energy industry is extending well beyond oil. Promising fast-growing green energy technologies and sectors are also suffering because the outbreak is disrupting China's industrial activity and manufacturing of crucial components for the solar, wind, and battery storage industries.

Much like China's oil demand slump impacts the global market, the Chinese slowdown in manufacturing of renewable energy components has a ripple effect throughout the global supply chain of major renewable energy industries.

The current situation highlights China's increased importance in the global energy markets over the past two decades since the SARS outbreak – from oil to battery storage, all energy sectors suffer when Chinese manufacturing and demand hits the brakes.

In the solar industry, factory shutdowns and production disruptions across China have delayed exports of solar panels and other components, disrupting the supply chain of the solar power industries and affecting solar projects in Asia and Australia. The disruption of the solar supply chain could become costly for as much as US$2.24 billion worth of solar projects across India, which relies on China for 80 percent of the solar modules it uses, CRISIL Ratings, an S&P Global company, said earlier this week. A total of 3 gigawatts (GW) of solar project across India risk incurring time and cost overruns, including penalties for missing commercial operation timelines, CRISIL noted.

"If the production interruption in mainland China lasts longer than one month, factories in south-east Asia and the US will start to see supply shortages that will reduce their production output," Xiaojing Sun, an Wood Mackenzie senior analyst in the energy transition research team, said last week, as carried by Renews.

Related: Why The World's Top Oil Traders Are Going Green

The coronavirus has not spared the wind power industry either.

Outbreak-related production disruptions will lower China's wind power installations by between 10 percent and 50 percent this year, depending on how soon the outbreak is contained and production returns to normal, WoodMac says, noting that its pre-virus outlook had estimated 28 GW capacity installations.

Outside China, the market with the greatest exposure—and therefore highest risk—is the United States, according to WoodMac. The U.S. wind industry sources components from China and is in a rush to have wind projects installed by the end of 2020 to keep federal subsidies.

"6 GW of installations targeting 2020 Commercial Operation Day were identified as at-risk before the outbreak, requiring Internal Revenue Service exemptions to maintain access to 100% value of the Production Tax Credit (PTC). This number is now likely to grow," WoodMac said, as carried by Recharge.

Last but not least, the coronavirus outbreak is putting the brakes on China's battery cell manufacturing, with the disruption already affecting production and the supply chain.

WoodMac expects China's battery cell output to contract by 10 percent, or 26 GWh, this year, and further delays and production disruptions are possible if factory slowdowns and travel restrictions remain in place for longer. The expected 26 GWh of lost production accounts for 7 percent the world's global production capacity, according to WoodMac.

Related: The New 'Must-Have' For Energy Hedge Funds

The lower Chinese battery production will not only impact the global electric vehicle (EV) and energy storage markets, but it could also challenge "the conventional narrative that EVs and grid storage projects will benefit from steady battery price declines," Greentech Media, a Wood Mackenzie Business, reported last week.

Depending on how soon China manages to contain the outbreak and have the manufacturing industry return to pre-coronavirus activity, the global wind, solar, and battery storage industries could be impacted for just a few weeks to a few months to well into the middle of this year.

But regardless of the extent of the impact, China's manufacturing and energy demand have grown so much over the past decade or two that any major Chinese disruption sends shockwaves through the global energy markets.

By Tsvetana Paraskova for Oilprice.com

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BUSINESS

Docket 32953,
APW's Ex 47 wntd
Rachel Wilson-Cross

Wisconsin solar installations delayed because of coronavirus; Minnesota developers worried

Wisconsin installations face setbacks with the coronavirus hurting China parts makers.

By Mike Hughlett (http://www.startribune.com/mike-hughlett/89522247/) Star Tribune

MARCH 4, 2020 — 7:35PM

Coronavirus-induced supply-chain breakdowns in China have caused the developers of two large solar-power projects in Wisconsin to declare force majeure, threatening construction delays. And some Minnesota solar companies are wary that manufacturing bottlenecks could soon hurt them, too.

"I'm definitely concerned about it because a lot of solar-project components come from Asia," said David Amster-Olszewski, CEO of Denver-based SunShare, which is a significant developer of community solar projects in Minnesota. And delays aren't the only problem.

"Any interruption impacts pricing for the whole supply chain," he said.

Asia, and particularly China, is the globe's primary supplier of solar cells and panels, and is also a major source of inverters and racking system components. Racks hold solar panels in place; inverters convert panels' DC current into AC.

Also, about 80% of the specialty glass used to manufacture solar panels comes from China, said Martin Pochtaruk, president of Heliene, a solar-panel maker in Mountain Iron, Minn.

"We have glass now," he said. "But are [shipping] containers going to start being delayed? We don't know yet."

In a solar panel, the energy-producing cells are basically sandwiched between glass and a "backsheet" made of polymers. Heliene has a potential problem with the latter component, too.

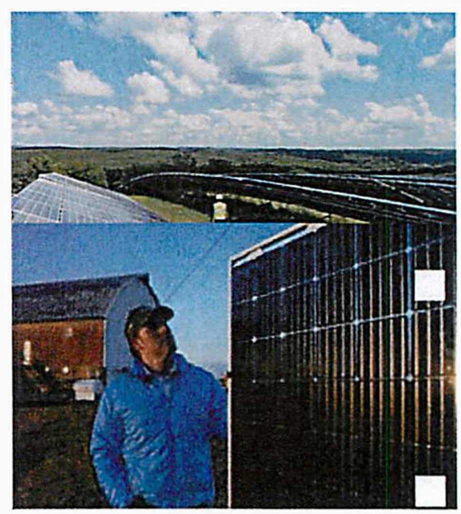
The company primarily sources its backsheets from a factory in the Lombardy region of northern Italy, which is also suffering a coronavirus outbreak. Production has been temporarily disrupted there, too, though Heliene still has some backsheet inventory.

In all, more than 94,000 people have contracted the virus worldwide, according to the Associated Press. More than 3,200 people have died, including more than 10 in the U.S. It has caused havoc with the Chinese economy and has spread to more than 80 countries, with significant outbreaks in South Korea, Iran and Italy.

Two solar developers last week declared "force majeure" on solar farms under construction in southwest and northeast Wisconsin. Force Majeure — "superior force" in Latin — is a contract clause invoked when extraordinary circumstances from weather to war prevent a contractor from meeting its obligations.

NextEra Energy Engineering and Construction, an arm of one of the nation's largest solar developers, declared force majeure because of factory shutdowns and travel restrictions in China, the company said in a filing with the Wisconsin Public Service Commission.

The interruptions are "adversely impacting" the delivery of racking systems to be used at the Two Creeks solar project about 30 miles southeast of Green Bay. Florida-based NextEra believes the delay will impinge on its work at Two Creeks and will require an "adjustment to the Project schedule," according to a regulatory filing.



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Invenergy's renewable-energy manager Dan Litchfield showed a single solar panel at the company's office in Cobb, Wis., in 2018. The

Chicago-based Invenergy, another large solar-power developer, declared force majeure on the Badger Hollow project near Montfort in southwestern Wisconsin. Invenergy said in a Wisconsin regulatory filing "there exists the potential for delays," and also cited travel restrictions and factory shutdowns in China.

Brendan Conway, a spokesman for the majority owner of the two solar projects, WEC Energy Group, said in an e-mail that construction on both continues. "It's too soon to say if international supply chain issues will cause any significant delays," WEC Energy Group said.

Two Creeks, which broke ground last summer, is Wisconsin's first large-scale solar project, with a planned 150 megawatts of capacity. Badger Hollow, a two-phase project that's also under construction, is even bigger with up to 300 megawatts.

By contrast, the largest solar farm in Minnesota is the 100-megawatt, 440,000-panel North Star project in Chisago County that supplies power to Xcel Energy. No other such large-scale "utility" solar projects are under construction.

But that's not the case for Minnesota's community solar gardens: small projects that usually produce up to one megawatt of power.

In January, Minnesota had around 150 community solar gardens either in the design or construction phase, according to a filing with the Minnesota Public Utilities Commission. The state already hosts around 270 community solar projects, which together provide more than 650 megawatts of power.

Xcel, which administers the state's community solar-garden program, said it has not heard of any construction delays because of coronavirus-induced supply-chain issues. A representative of a Minnesota trade group for the solar industry said the same. Still, worries about supply-chain failures are radiating through the industry.

"Obviously we are very concerned about coronavirus and we are getting initial reports of supply disruptions," said John Smirnow, vice president of market strategy and general counsel for the Solar Energy Industries Association, a national trade group.

"While those reports are limited in scope now, companies are making contingency plans and backup arrangements in the event of more significant disruptions."

Mike Hughlett covers energy and other topics for the Star Tribune, where he has worked since 2010. Before that he was a reporter at newspapers in Chicago, St. Paul, New Orleans and Duluth.

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U.S. DEPARTMENT OF ENERGY

A.P.S.C. DOCKET NO 32953
APCo 's EX. NO. 48
WITNESS: Wilson-Cross

State of Alabama
ENERGY SECTOR RISK PROFILE

This State Energy Risk Profile examines the relative magnitude of the risks that the State of Alabama's energy infrastructure routinely encounters in comparison with the probable impacts. Natural and man-made hazards with the potential to cause disruption of the energy infrastructure are identified.

The Risk Profile highlights risk considerations relating to the electric, petroleum and natural gas infrastructures to become more aware of risks to these energy systems and assets.

ALABAMA STATE FACTS

State Overview

Population: 4.83 million (2% total U.S.)
Housing Units: 2.19 million (2% total U.S.)
Business Establishments: 0.10 million (1% total U.S.)

Annual Energy Consumption

Electric Power: 86.2 TWh (2% total U.S.)
Coal: 24,300 MSTN (3% total U.S.)
Natural Gas: 87 Bcf (<1% total U.S.)
Motor Gasoline: 47,300 Mbarrels (2% total U.S.)
Distillate Fuel: 27,900 Mbarrels (2% total U.S.)

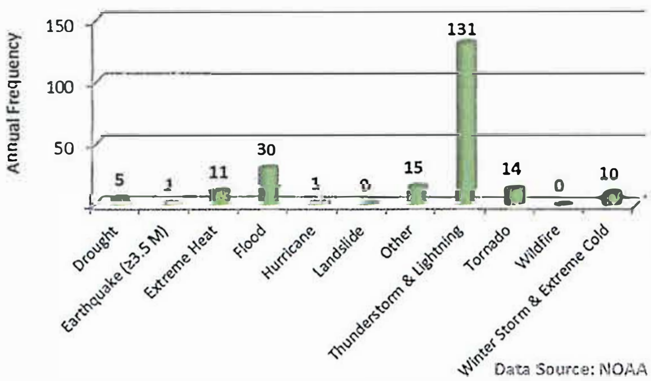
Annual Energy Production

Electric Power Generation: 152.9 TWh (4% total U.S.)
- Coal: 45.6 TWh, 30% [12.6 GW total capacity]
- Petroleum: 0.1 TWh, <1% [0.05 GW total capacity]
- Natural Gas: 55.7 TWh, 36% [13.5 GW total capacity]
- Nuclear: 40.8 TWh, 27% [5.3 GW total capacity]
- Hydro: 7.4 TWh, 5% [3.3 GW total capacity]
- Other Renewable: 0 TWh, 0% [0 GW total capacity]

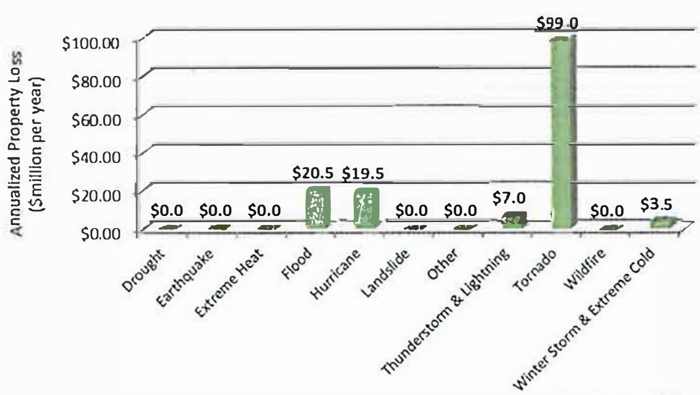
Coal: 19,500 MSTN (2% total U.S.)
Natural Gas: 220 Bcf (1% total U.S.)
Crude Oil: 9,500 Mbarrels (<1% total U.S.)
Ethanol: 0 Mbarrels (0% total U.S.)

NATURAL HAZARDS OVERVIEW

Annual Frequency of Occurrence of Natural Hazards in Alabama (1996–2014)



Annualized Property Loss due to Natural Hazards in Alabama (1996–2014)



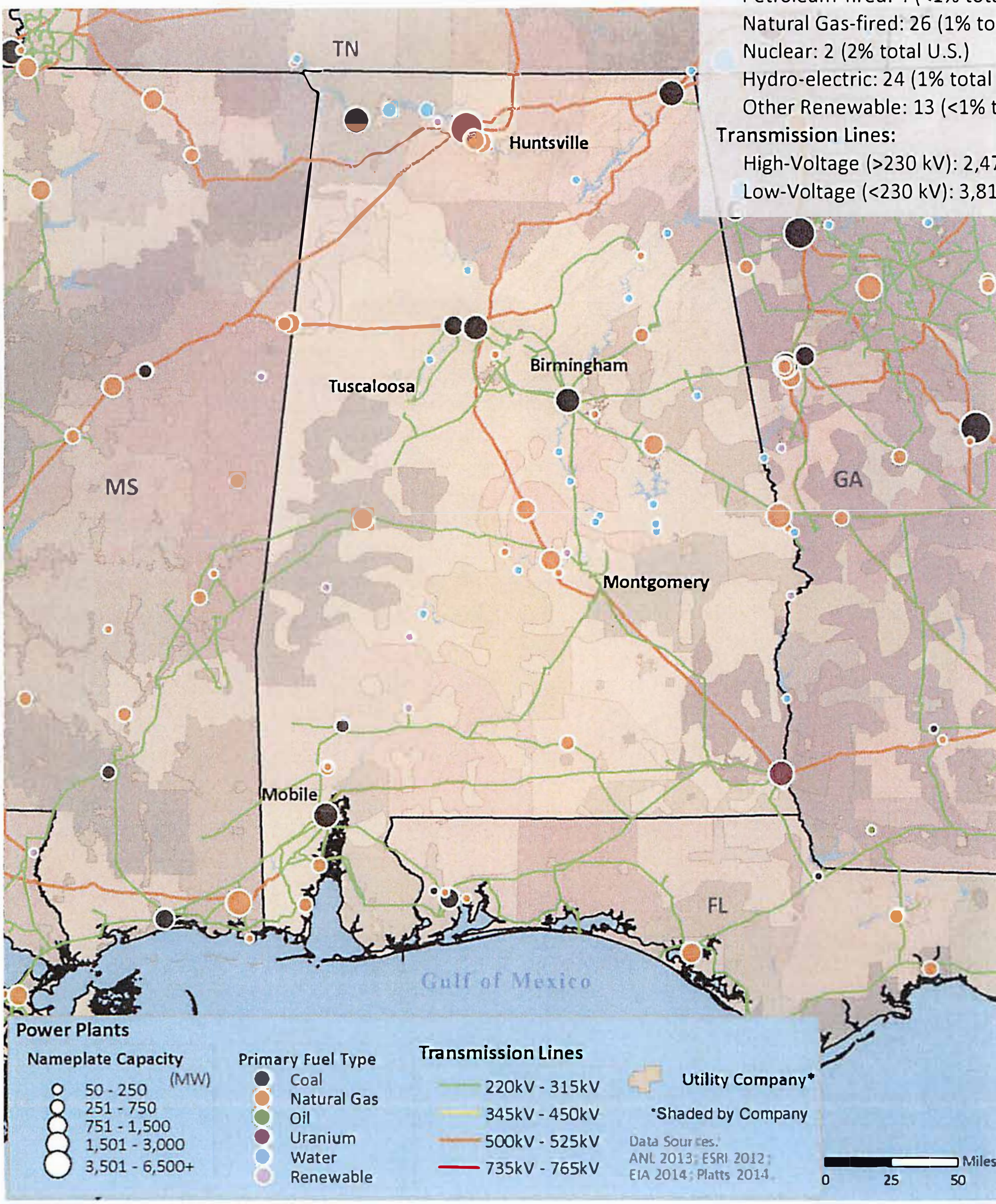
- According to NOAA, the most common natural hazard in Alabama is Thunderstorm & Lightning, which occurs once every 2.8 days on the average during the months of March to October.
- The second-most common natural hazard in Alabama is Flood, which occurs once every 12.2 days on the average.
- As reported by NOAA, the natural hazard in Alabama that caused the greatest overall property loss during 1996 to 2014 is Tornado at $99.0 million per year.
- The natural hazard with the second-highest property loss in Alabama is Flood at $20.5 million per year.

Produced by Department of Energy (DOE), Office of Electricity Delivery & Energy Reliability (OE)

ELECTRIC

Electric Power Plants: 79 (1% total U.S.)
- Coal-fired: 10 (1% total U.S.)
- Petroleum-fired: 4 (<1% total U.S.)
- Natural Gas-fired: 26 (1% total U.S.)
- Nuclear: 2 (2% total U.S.)
- Hydro-electric: 24 (1% total U.S.)
- Other Renewable: 13 (<1% total U.S.)

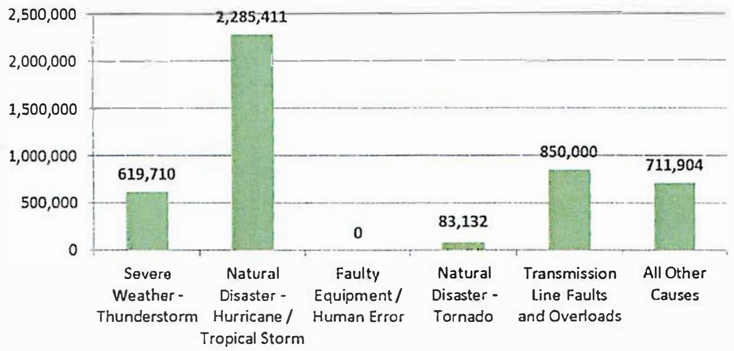
Transmission Lines:
- High-Voltage (>230 kV): 2,470 Miles
- Low-Voltage (<230 kV): 3,816 Miles



Electric Transmission

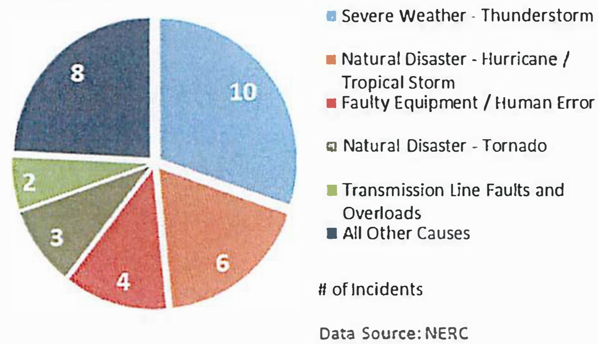
- According to NERC, the leading cause of electric transmission outages in Alabama is Severe Weather - Thunderstorm.
- Alabama experienced 33 electric transmission outages from 1992 to 2009, affecting a total of 4,550,157 electric customers.
- Natural Disaster - Hurricane/Tropical Storm affected the largest number of electric customers as a result of electric transmission outages.

Electric Customers Disrupted by NERC-Reported Electric Transmission Outages by Cause (1992–2009)



Data Source: NERC

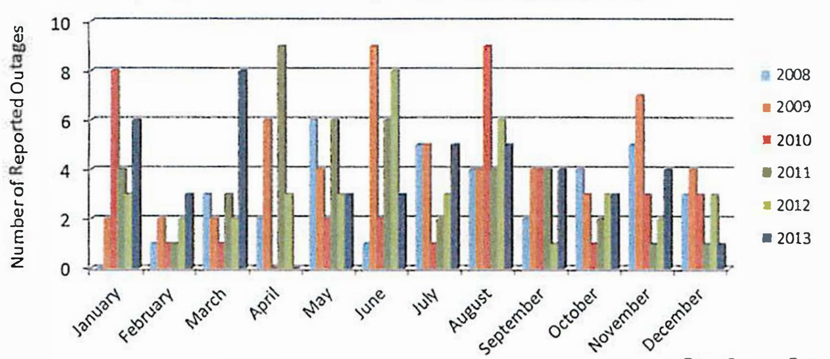
Number of NERC-Reported Electric Transmission Outages by Cause (1992–2009)



Data Source: NERC

Electric Distribution

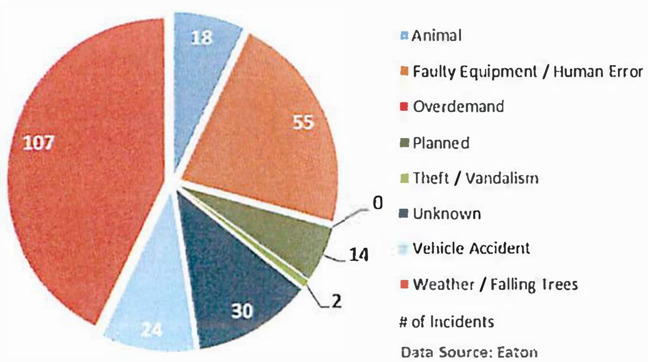
Electric Utility Reported Power Outages by Month (2008–2013)



Data Source: Eaton

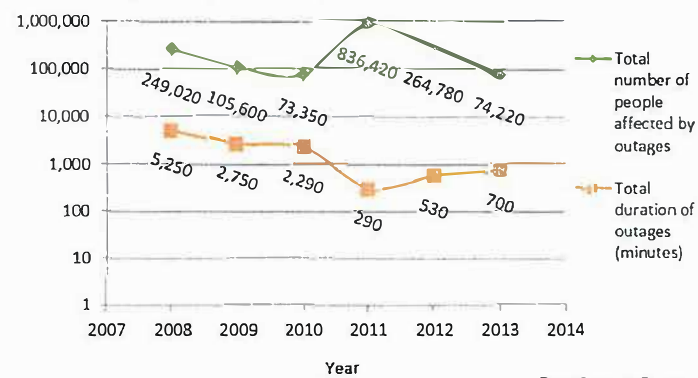
- Between 2008 and 2013, the greatest number of electric outages in Alabama has occurred during the month of August.
- The leading cause of electric outages in Alabama during 2008 to 2013 was Weather/Falling Trees.
- On average, the number of people affected annually by electric outages during 2008 to 2013 in Alabama was 267,232.
- The average duration of electric outages in Alabama during 2008 to 2013 was 1,968 minutes or 32.8 hours a year.

Causes of Electric-Utility Reported Outages (2008–2013)



Data Source: Eaton

Utility Outage Data (2008–2013)



Data Source: Eaton

- NOTE: # of Incidents – The number within each pie slice is the number of event incidents attributable to each cause.

PETROLEUM

Petroleum Infrastructure Overview

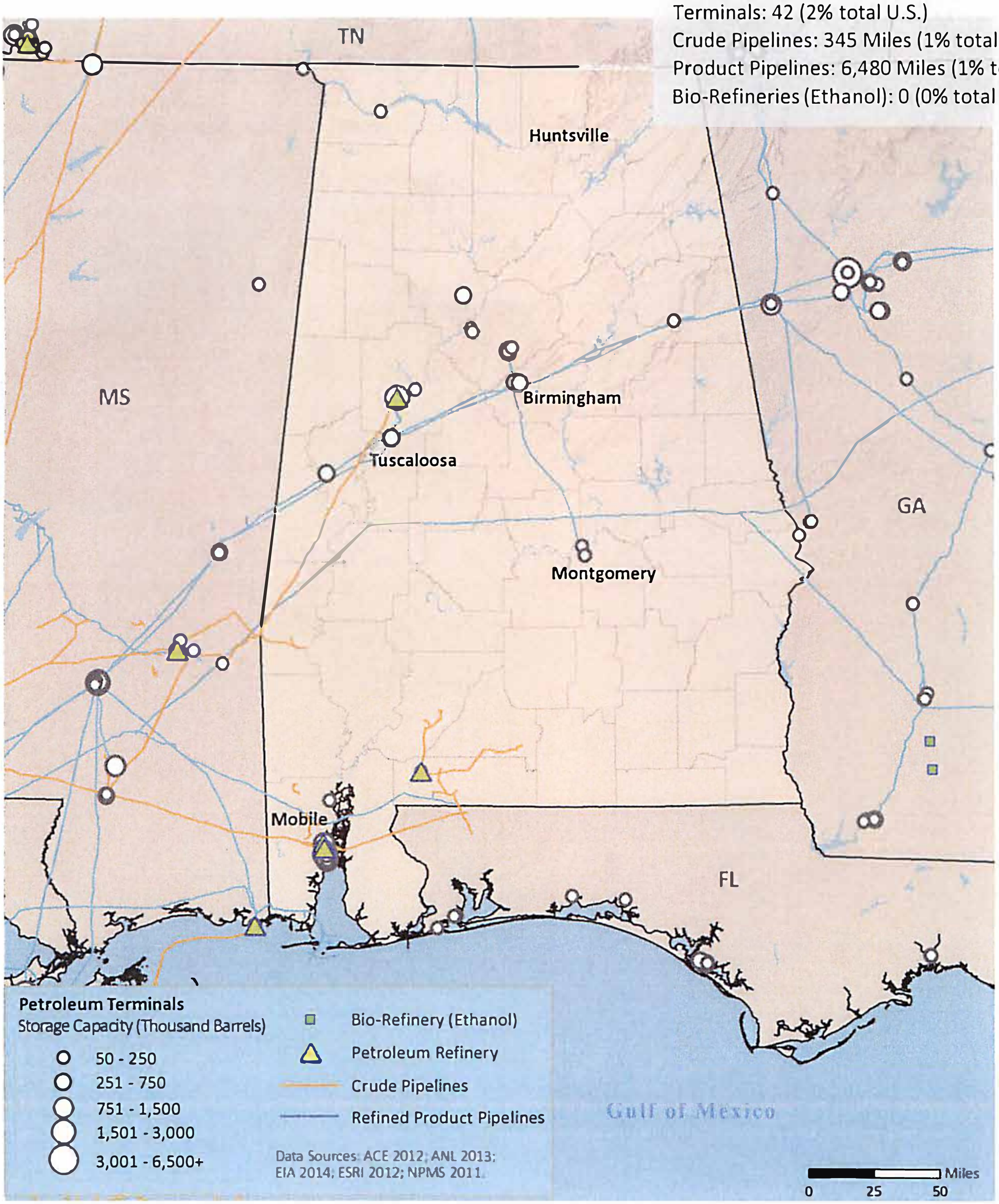
Refineries: 3 (2% total U.S.)

Terminals: 42 (2% total U.S.)

Crude Pipelines: 345 Miles (1% total U.S.)

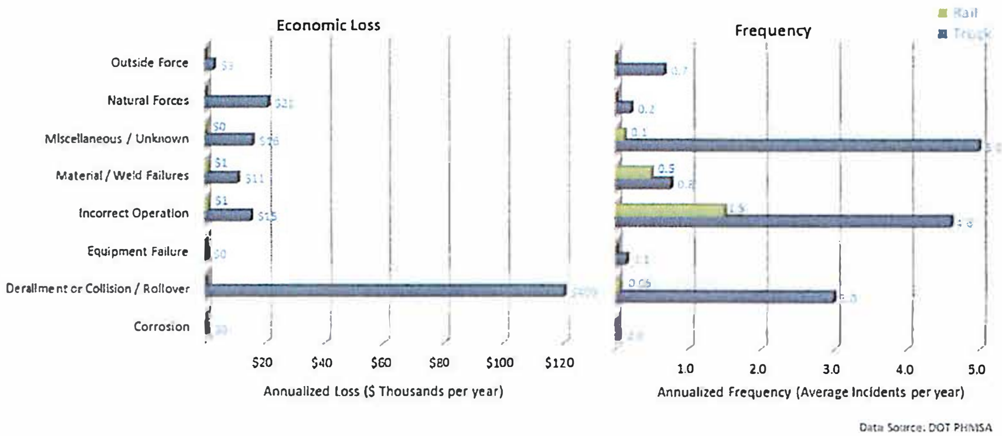
Product Pipelines: 6,480 Miles (1% total U.S.)

Bio-Refineries (Ethanol): 0 (0% total U.S.)



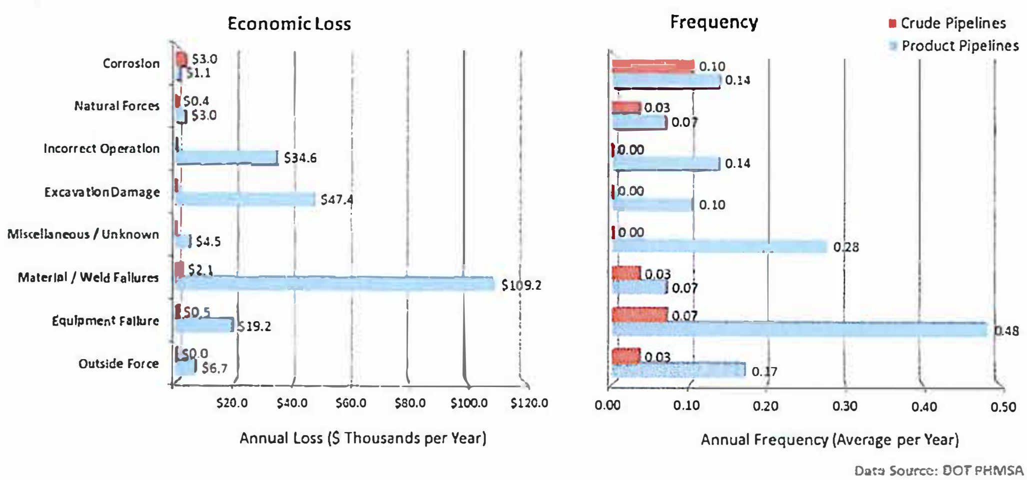
Petroleum Transport

Top Events Affecting Petroleum Transport by Truck and Rail (1986–2014)



❱ The leading event type affecting the transport of petroleum product by rail and truck in Alabama during 1986 to 2014 was Incorrect Operation for rail transport and Miscellaneous/ Unknown for truck transport, with an average 1.5 and 5.0 incidents per year, respectively.

Top Events Affecting Crude Oil and Refined Product Pipelines in Alabama (1986–2014)

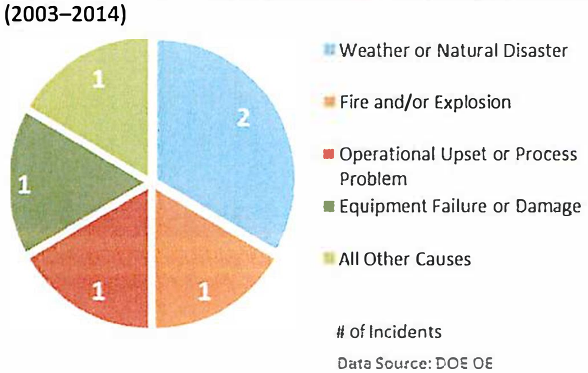


❱ The leading event type affecting crude oil pipeline and petroleum product pipelines in Alabama during 1986 to 2014 was Corrosion for crude oil pipelines and Equipment Failure for product pipelines, with an average 0.1 and 0.48 incidents per year (or one incident every 9.7 and 2.1 years), respectively.

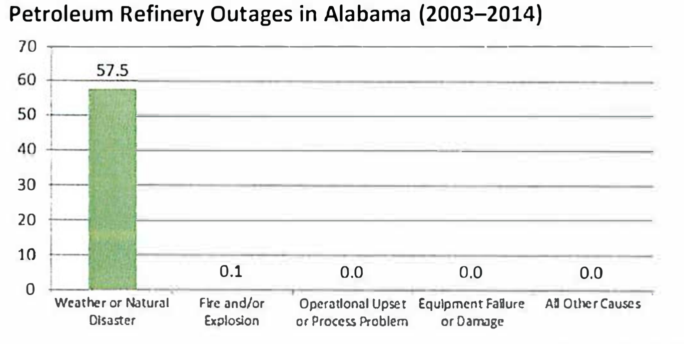
Petroleum Refinery

❱ The leading cause of petroleum refinery disruptions in Alabama from 2003 to 2014 was Weather or Natural Disaster. Alabama's petroleum refineries experienced 6 major incidents from 2003 to 2014. The average production impact from disruptions of Alabama's refineries from 2003 to 2014 is 19.2 thousand barrels per day.

Top-Five Causes of Petroleum Refinery Disruptions in Alabama (2003–2014)



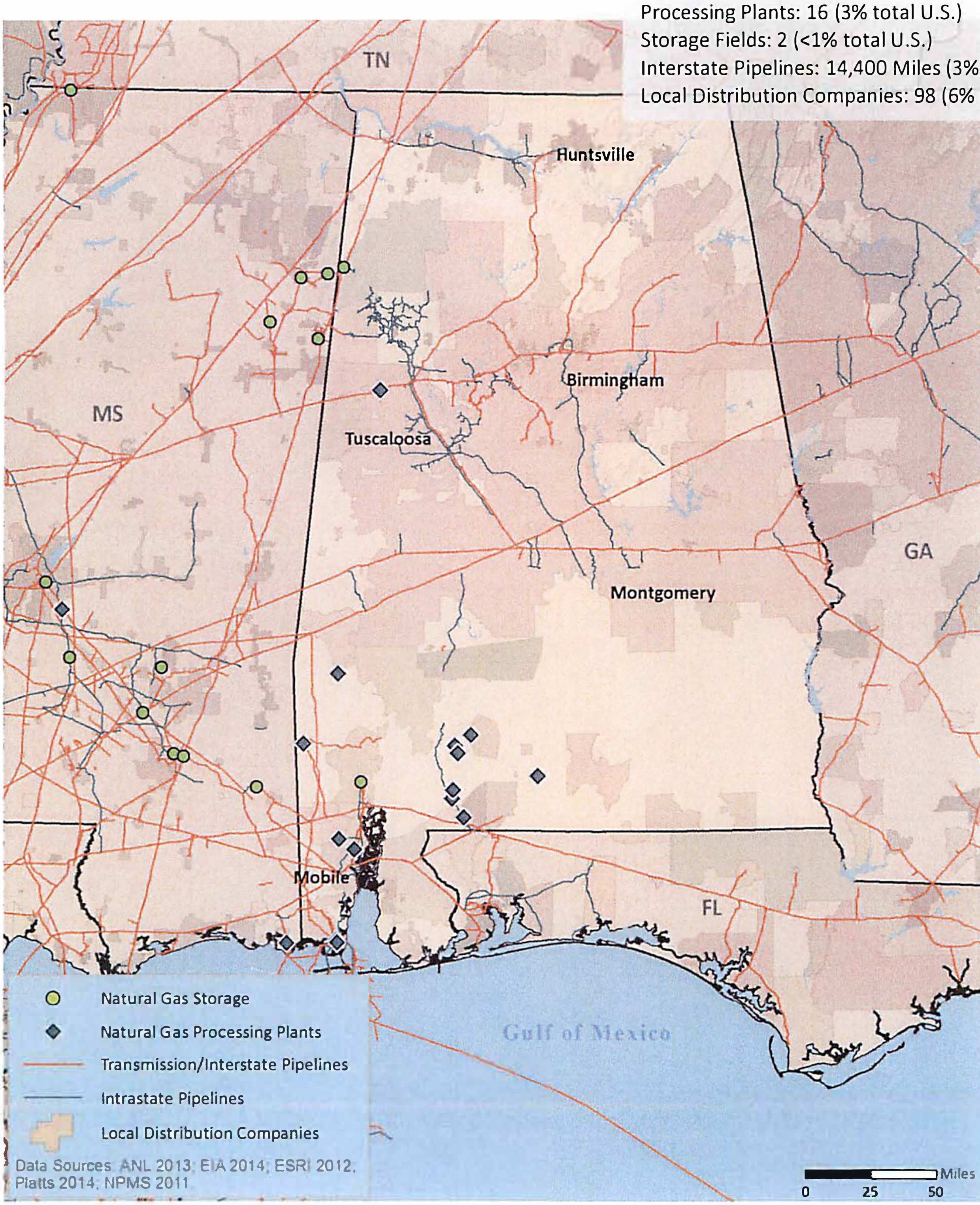
Average Production Impact (thousand barrels per day) from Petroleum Refinery Outages in Alabama (2003–2014)



NATURAL GAS

Natural Gas Infrastructure Overview

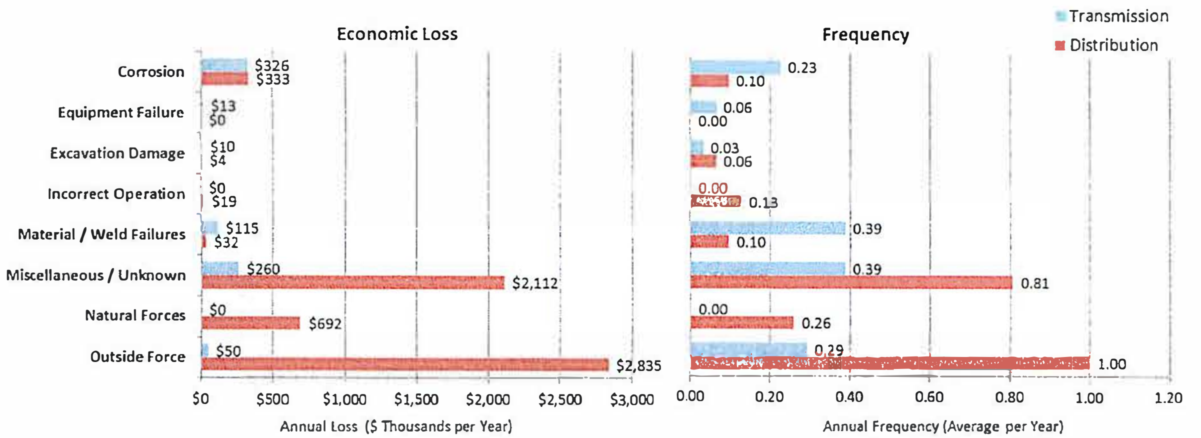
Gas Wells: 6,068 (1% total U.S.)
Processing Plants: 16 (3% total U.S.)
Storage Fields: 2 (<1% total U.S.)
Interstate Pipelines: 14,400 Miles (3% total U.S.)
Local Distribution Companies: 98 (6% total U.S.)



Natural Gas Transport

- The leading event type affecting natural gas transmission and distribution pipelines in Alabama during 1986 to 2014 was Material/Weld Failures for Transmission Pipelines and Outside Force for Distribution Pipelines, with an average 0.39 and 1.00 incidents per year (or one incident every 2.6 years and 1 year), respectively.

Top Events Affecting Natural Gas Transmission and Distribution in Alabama (1986-2014)



Data Source: DOT PHMSA

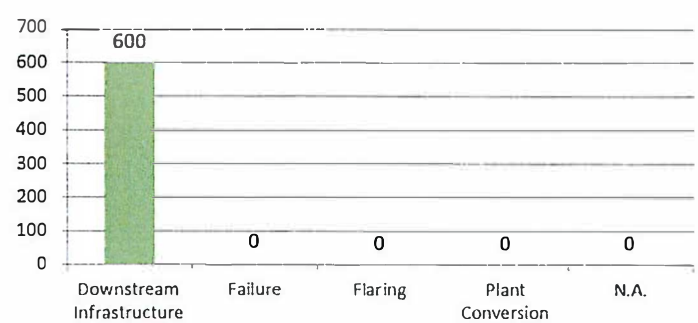
Natural Gas Processing

- According to data derived from DOE's Energy Assurance Daily, the leading cause of natural gas processing plant disruptions in Alabama from 2005 to 2014 is Downstream Infrastructure.
- Alabama's natural gas processing plants experienced 1 disruption from 2005 to 2014.
- The average production impact from disruptions of Alabama's natural gas processing plants from 2005 to 2014 is 600 million cubic feet per day (MMcfd).

Top Cause of Natural Gas Processing Plant Disruptions in Alabama (2005–2014)

Data Source: DOE OE

Average Production Impact (MMcfd) from Natural Gas Processing Plant Disruptions in Alabama (2005–2014)



Data Source: DOE OE

DATA SOURCES

Bcf – Billion Cubic Feet
GW – Gigawatt
kV – Kilovolt
Mbarrels – Thousand Barrels
Mbpd – Thousand Barrels per Day
MMcfd – Million Cubic Feet per Day
MSTN – Thousand Short Tons
TWh – Terawatt hours

Overview Information

- NOAA (2014) Storms Events Database [www.ncdc.noaa.gov/data-access/severe-weather]
- Census Bureau (2012) State and County QuickFacts [http://quickfacts.census.gov/qfd/ download_data.html]

Production Numbers

- EIA (2012) Table P1 Energy Production Estimates in Physical Units [http://www.eia.gov/state/seds/sep_prod/pdf/P1.pdf]
- EIA (2013) Natural Gas Gross Withdrawals and Production [http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm]
- EIA (2012) Electric Power Annual, Table 3.6. Net Generation by State, by Sector, 2012 and 2011 (Thousand Megawatt hours) [http://www.eia.gov/electricity/annual/pdf/epa.pdf]
- EIA (2012) Electric Power Annual, Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860) [http://www.eia.gov/electricity/data/state/]

Consumption Numbers

- EIA (2012) Electric Power Annual, Fossil Fuel Consumption for Electricity Generation by Year, Industry Type and State (EIA-906, EIA-920, and EIA-923) [http://www.eia.gov/electricity/data/state/]
- EIA (2013) Prime Supplier Sales Volumes [http://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm]
- EIA (2012) Adjusted Sales of Fuel Oil and Kerosene [http://www.eia.gov/petroleum/data.cfm#consumption]
- EIA (2012) Annual Coal Consumption [http://www.eia.gov/coal/data.cfm]

Electricity

- EIA (2013) Form-860 Power Plants [http://www.eia.gov/electricity/data/eia860/]
- Platts (2014 Q2) Transmission Lines (Miles by Voltage Level)
- Platts (2014 Q2) Power Plants (Production and Capacity by Type)

Petroleum

- Argonne National Laboratory (2012) Petroleum Terminal Database
- Argonne National Laboratory (2014) Ethanol Plants
- EIA (2013) Petroleum Refinery Capacity Report [http://www.eia.gov/petroleum/refinerycapacity/]
- NPMS (2011) Petroleum Product Pipeline (Miles of Interstate Pipeline)
- NPMS (2011) Crude Pipeline (Miles of Interstate Pipeline)

Natural Gas

- EIA (2013) Form-767 Natural Gas Processing Plants [http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP9]
- EIA (2013) Number of Producing Gas Wells [http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm]
- NPMS (2011) Natural Gas Pipeline (Miles of Interstate Pipeline)
- Platts (2014 Q2) Local Distribution Companies (LDCs)

Event Related

- DOE OE (2014) Form 417 Electric Disturbance Events [http://www.oe.netl.doe.gov/OE417_annual_summary.aspx]
- DOE OE (2014) Energy Assurance Daily (EAD) [http://www.oe.netl.doe.gov/ead.aspx]
- Eaton (2014) Blackout and Power Outage Tracker [http://powerquality.eaton.com/blackouttracker/default.asp?id=&key=&Quest_user_id=&leadg_Q_QRequired=&site=&menu=&cx=3&x=16&y=11]
- DOT PHMSA (2013) Hazardous Material Incident System (HMIS) [https://hazmatonline.phmsa.dot/gov/IncidentReportsSearch/search.aspx]
- NERC (2009) Disturbance Analysis Working Group [http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx]*
  *The NERC disturbance reports are not published after 2009.

Notes

- Natural Hazard, Other, includes extreme weather events such as astronomical low tide, dense smoke, frost/freeze, and rip currents.
- Each incident type is an assembly of similar causes reported in the data source. Explanations for the indescribable incident types are below.
  - Outside Force refers to pipeline failures due to vehicular accident, sabotage, or vandalism.
  - Natural Forces refers to damage that occurs as a result of naturally occurring events (e.g., earth movements, flooding, high winds, etc.)
  - Miscellaneous/Unknown includes releases or failures resulting from any other cause not listed or of an unknowable nature.
  - Overdemand refers to outages that occur when the demand for electricity is greater than the supply, causing forced curtailment.
- Number (#) of Incidents – The number within each pie chart piece is the number of outages attributable to each cause.

FOR MORE INFORMATION CONTACT:
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APCo 's EX. NO 49
WITNESS Wilson-Gross

Bloomberg Green

Fragments of wind turbine blades await burial at the Casper Regional Landfill in Wyoming.
Photographer: Benjamin Rasmussen for Bloomberg Green

Wind Turbine Blades Can't Be Recycled, So They're Piling Up in Landfills

https://www.bloomberg.com/news/features/2020-02-05/wind-turbine-blades-can-t-be-recycled-so-they-re-piling-up-in-landfills

Companies are searching for ways to deal with the tens of thousands of blades that have reached the end of their lives.

By

Chris Martin

February 5, 2020, 4:00 AM CST Updated on February 7, 2020, 10:54 AM CST

A wind turbine's blades can be longer than a Boeing 747 wing, so at the end of their lifespan they can't just be hauled away. First, you need to saw through the lissome fiberglass using a diamond-encrusted industrial saw to create three pieces small enough to be strapped to a tractor-trailer.

The municipal landfill in Casper, Wyoming, is the final resting place of 870 blades whose days making renewable energy have come to end. The severed fragments look like bleached whale bones nestled against one another.

"That's the end of it for this winter," said waste technician Michael Bratvold, watching a bulldozer bury them forever in sand. "We'll get the rest when the weather breaks this spring."

Tens of thousands of aging blades are coming down from steel towers around the world and most have nowhere to go but landfills. In the U.S. alone, about 8,000 will be removed in each of the next four years. Europe, which has been dealing with the problem longer, has about 3,800 coming down annually through at least 2022, according to BloombergNEF. It's going to get worse: Most were built more than a decade ago, when installations were less than a fifth of what they are now.

Built to withstand hurricane-force winds, the blades can't easily be crushed, recycled or repurposed. That's created an urgent search for alternatives in places that lack wide-open prairies. In the U.S., they go to the handful of landfills that accept them, in Lake Mills, Iowa; Sioux Falls, South Dakota; and Casper, where they will be interred in stacks that reach 30 feet under.

"The wind turbine blade will be there, ultimately, forever," said Bob Cappadona, chief operating officer for the North American unit of Paris-based Veolia Environnement

SA, which is searching for better ways to deal with the massive waste. "Most landfills are considered a dry tomb."

"The last thing we want to do is create even more environmental challenges."

Each blade is cut into pieces for transport and stacked for efficiency.

Photographer: Benjamin Rasmussen for Bloomberg Green

To prevent catastrophic climate change caused by burning fossil fuels, many governments and corporations have pledged to use only clean energy by 2050. Wind energy is one of the cheapest ways to reach that goal.

The electricity comes from turbines that spin generators. Modern models emerged after the 1973 Arab oil embargo, when shortages compelled western governments to find alternatives to fossil fuels. The first wind farm in the U.S. was installed in New

Hampshire in 1980, and California deployed thousands of turbines east of San Francisco across the Altamont Pass.

The first models were expensive and inefficient, spinning fast and low. After 1992, when Congress passed a tax credit, manufacturers invested in taller and more powerful designs. Their steel tubes rose 260 feet and sported swooping fiberglass blades. A decade later, General Electric Co. made its 1.5 megawatt model—enough to supply 1,200 homes in a stiff breeze—an industry standard.

Wind power is carbon-free and about 85% of turbine components, including steel, copper wire, electronics and gearing can be recycled or reused. But the fiberglass blades remain difficult to dispose of. With some as long as a football field, big rigs can only carry one at a time, making transportation costs prohibitive for long-distance hauls. Scientists are trying to find better ways to separate resins from fibers or to give small chunks new life as pellets or boards.

Until large-scale recycling is widely available, landfills must accommodate defunct blades.

Photographer: Benjamin Rasmussen for Bloomberg Green

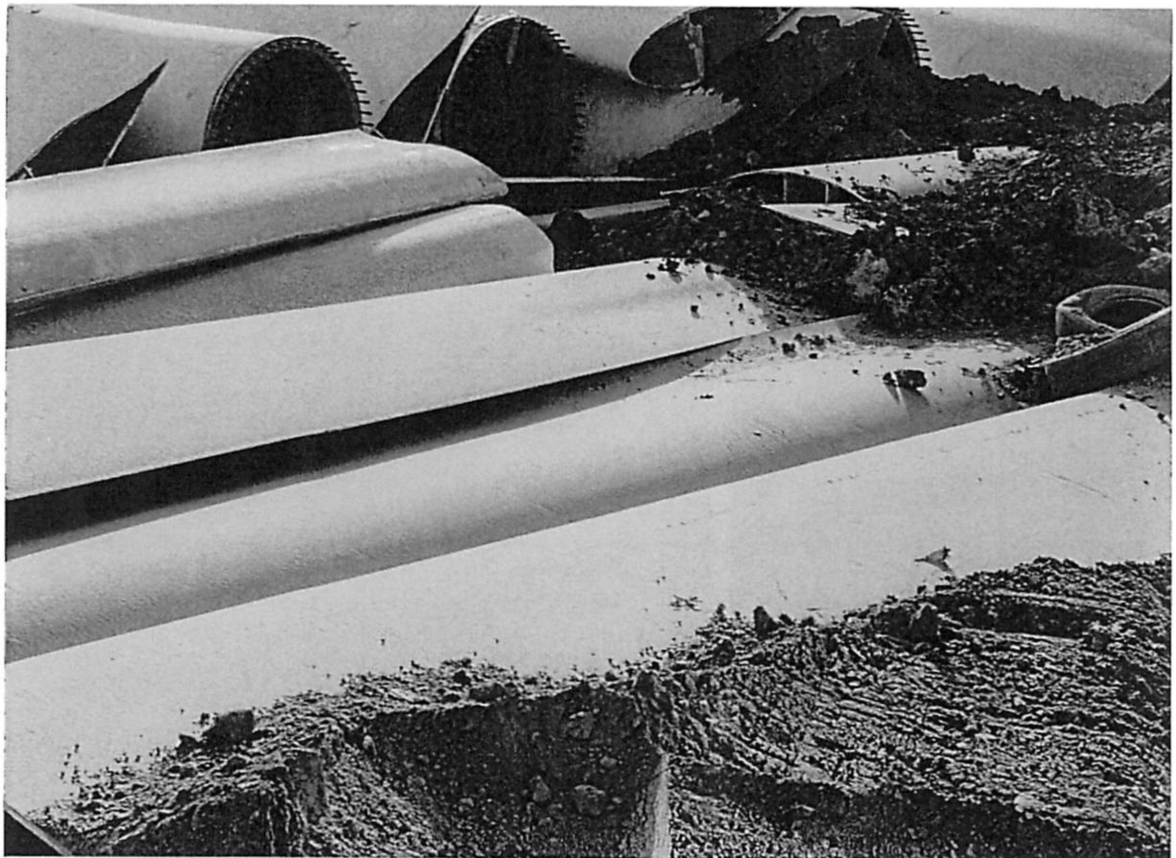
In the European Union, which strictly regulates material that can go into landfills, some blades are burned in kilns that create cement or in power plants. But their energy content is weak and uneven and the burning fiberglass emits pollutants.

In a pilot project last year, Veolia tried grinding them to dust, looking for chemicals to extract. "We came up with some crazy ideas," Cappadona said. "We want to make it a sustainable business. There's a lot of interest in this."

Thousands of Wind Turbine Blades Wind Up in Landfills

One start-up, Global Fiberglass Solutions, developed a method to break down blades and press them into pellets and fiber boards to be used for flooring and walls. The company started producing samples at a plant in Sweetwater, Texas, near the continent's largest concentration of wind farms. It plans another operation in Iowa.

"We can process 99.9% of a blade and handle about 6,000 to 7,000 blades a year per plant," said Chief Executive Officer Don Lilly. The company has accumulated an inventory of about one year's worth of blades ready to be chopped up and recycled as demand increases, he said. "When we start to sell to more builders, we can take in a lot more of them. We're just gearing up."



Workers are experimenting with methods to fit more blades in their graves.

Photographer: Benjamin Rasmussen for Bloomberg Green

Until then, municipal and commercial dumps will take most of the waste, which the American Wind Energy Association in Washington says is safest and cheapest.

"Wind turbine blades at the end of their operational life are landfill-safe, unlike the waste from some other energy sources, and represent a small fraction of overall U.S. municipal solid waste," according to an emailed statement from the group. It pointed to an Electric Power Research Institute study that estimates all blade waste through 2050 would equal roughly .015% of all the municipal solid waste going to landfills in 2015 alone.

In Iowa, Waste Management Inc. "worked closely with renewable energy companies to come up with a solution for wind mill blade processing, recycling and disposal," said Julie Ketchum, a spokeswoman. It disposes all the blades it receives, with as many as 10 trucks per day hauling them to the company's Lake Mills landfill.

Back in Wyoming, in the shadow of a snow-capped mountain, lies Casper, where wind farms represent both the possibilities and pitfalls of the shift from fossil fuels. The boom-bust oil town was founded at the turn of the 19th century. On the south side, bars that double as liquor stores welcome cigarette smokers and day drinkers. Up a gentle northern slope, a shooting club boasts of cowboy-action pistol ranges. Down the road, the sprawling landfill bustles and a dozen wind turbines spin gently on the horizon. They tower over pumpjacks known as nodding donkeys that pull oil from wells.

"People around here don't like change," said Morgan Morsett, a bartender at Frosty's Bar & Grill. "They see these wind turbines as something that's hurting coal and oil."

But the city gets $675,000 to house turbine blades indefinitely, which can help pay for playground improvements and other services. Landfill manager Cynthia Langston said the blades are much cleaner to store than discarded oil equipment and Casper is happy to take the thousand blades from three in-state wind farms owned by Berkshire Hathaway Inc.'s PacifiCorp. Warren Buffett's utility has been replacing the original blades and turbines with larger, more powerful models after a decade of operation.

Wind farms, common in Wyoming, overlook the Casper landfill.

Photographer: Benjamin Rasmussen for Bloomberg Green

While acknowledging that burying blades in perpetuity isn't ideal, Bratvold, the special waste technician, was surprised by some of the negative reactions when a photo of some early deliveries went viral last summer. On social media, posters derided the inability to recycle something advertised as good for the planet, and offered suggestions of reusing them as links in a border wall or roofing for a homeless shelter.

"The backlash was instant and uninformed," Bratvold said. "Critics said they thought wind turbines were supposed to be good for the environment and how can it be sustainable if it ends up in a landfill?"

"I think we're doing the right thing."

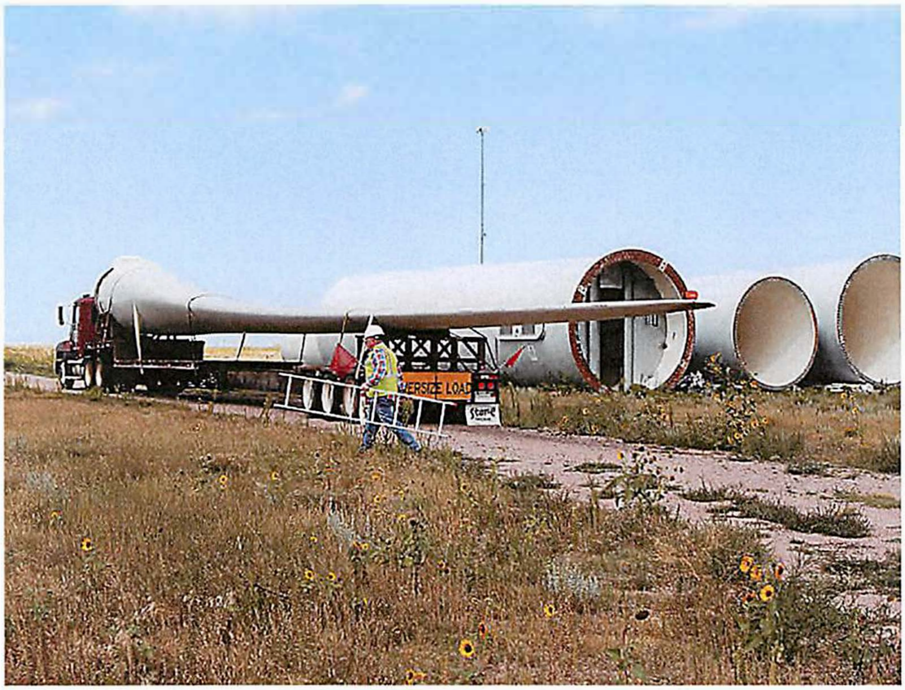
In the meantime, Bratvold and his co-workers have set aside about a half dozen blades and in coming months, they'll experiment with methods to squeeze them into smaller footprints. They've tried bunkers, berms and even crushing them with the bulldozer, but the tracks kept slipping off the smooth blades. There's little time to waste. Spring is coming, and when it does, the inexorable march of blades will resume.

Unfurling The Waste Problem Caused By Wind Energy

September 10, 20194:37 PM ET
Heard on All Things Considered

CHRISTINA STELLA

FROMHARVEST PUBLIC MEDIA



Rob Van Vleet secures a wind turbine blade onto an oversize truck at the Kimball Wind Farm in southwest Nebraska.
Christina Stella Harvest Public Media

While most of a turbine can be recycled or find a second life on another wind farm, researchers estimate the U.S. will have more than 720,000 tons of blade material to dispose of over the next 20 years, a figure that doesn't include newer, taller higher-capacity versions.

There aren't many options to recycle or trash turbine blades, and what options do exist are expensive, partly because the U.S. wind industry is so young. It's a waste problem that runs counter to what the industry is held up to be: a perfect solution for environmentalists looking to combat climate change, an attractive investment for companies such as Budweiser and Hormel Foods, and a job creator across the Midwest and Great Plains.

At the end of a long gravel road on the southwest Nebraska prairie, the state's first wind farm, Kimball Wind Project, is caught in the breeze. But the turbine scrap area looks more like a sci-fi drama set. Rob Van Vleet climbed atop a 127-foot-long turbine blade and walked the length like a plank.

"These towers may be supporting as much as 150,000 pounds, 250 feet in the air," Van Vleet said. "The stands are an inch and a half thick steel ... so they're very strong."

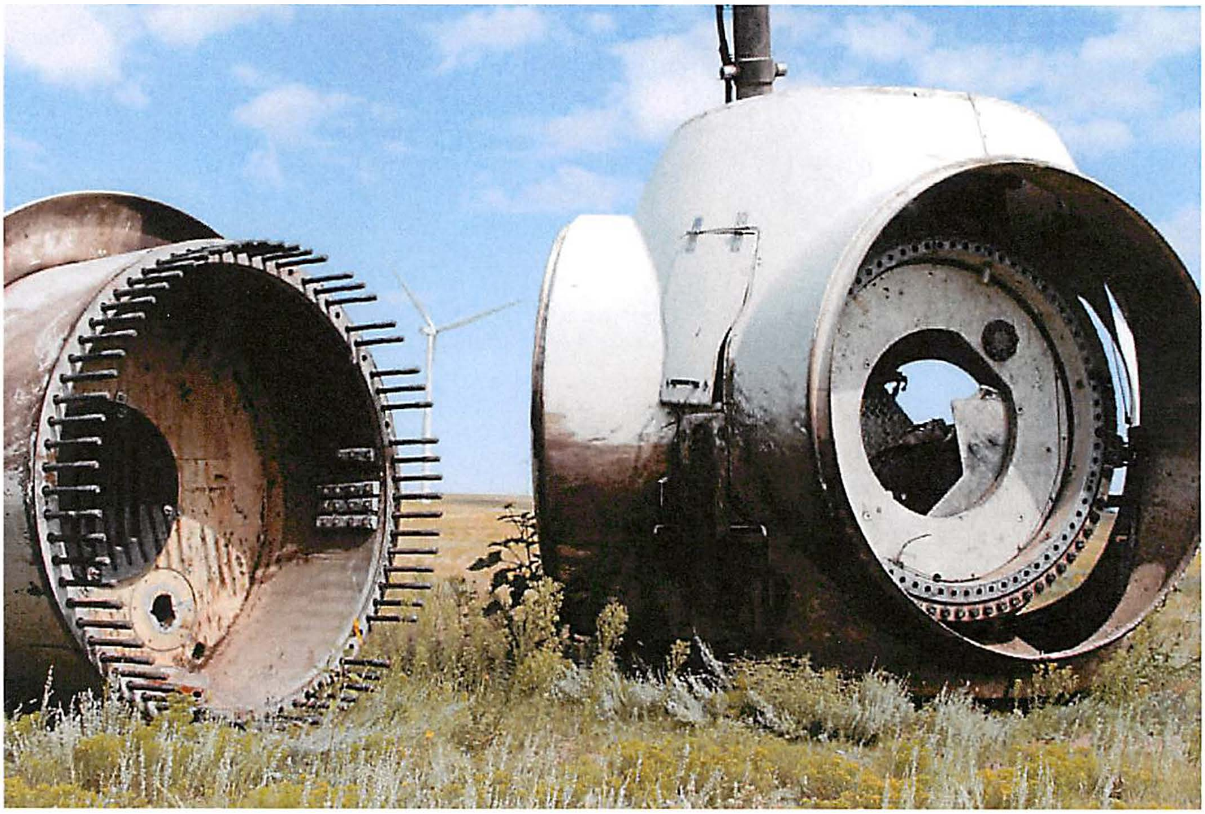
Ninety percent of a turbine's parts can be recycled or sold, according to Van Vleet, but the blades, made of a tough but pliable mix of resin and fiberglass — similar to what spaceship parts are made from — are a different story.

"The blades are kind of a dud because they have no value," he said.

Decommissioned blades are also notoriously difficult and expensive to transport. They can be anywhere from 100 to 300 feet long and need to be cut up onsite before getting trucked away on specialized equipment — which costs money — to the landfill.

Once there, Van Vleet said, the size of the blades can put landfills in a tough spot.

"If you're a small utility or municipality and all of a sudden hundreds of blades start coming to your landfill, you don't want to use up your capacity for your local municipal trash for wind turbine blades," he said, adding that permits for more landfill space add another layer of expenses.



These old wind turbine hubs will be scrapped.
Christina Stella/Harvest Public Media

Cindy Langstrom manages the turbine blade disposal project for the municipal landfill in Casper, Wyo. Though her landfill is one of the only ones in the state — not to mention the entire U.S. — with enough space to take wind farm waste, she said the blades' durability initially posed a financial hurdle.

"Our crushing equipment is not big enough to crush them," she said.

Langstrom's team eventually settled on cutting up the blades into three pieces and stuffing the two smaller sections into the third, which was cheaper than renting stronger crushing machines that are usually made for mining.

Karl Englund, a researcher and chief technology officer of Global Fiberglass Solutions, said recycling turbine blades is more regulated in countries that have had wind power for decades. The European Union has waste management rules, so some European companies sell older parts to customers in Asia and Latin America.

"[In Europe], land is at a premium, and you're not allowed to throw things away," he said. "So you have to do it."

Englund believes he's found a way to recycle blades by grinding them up to make chocolate chip-sized pellets. They can be used for decking materials, pallets and piping. His startup opened its first processing facility in central Texas this year, and it's leasing a second space near Des Moines, Iowa.

Van Vleet said finding better ways to decommission wind farms will be an uphill battle, but when it comes to confronting the looming waste issue, "it's something that's happening, whether we like it or not, so we just as well get in on it."

He's exploring his own way to decrease the industry's landfill footprint, in hopes that blade recycling can blossom into a local industry. And for rural areas looking for an economic boost, Van Vleet thinks his risk of recycling just might pay off.

"Out on the prairie, there's not very much scrap," he said. "The idea is to develop the next technology, otherwise, I wouldn't be doing this.

"We lose money on every blade we haul."

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MOTHERBOARD
TECH BY VICE

We Don't Mine Enough Rare Earth Metals to Replace Fossil Fuels With Renewable Energy

Rare earth metals are used in solar panels and wind turbines – as well as electric cars and consumer electronics. We don't recycle them, and there's not enough to meet growing demand.

By Nafeez Ahmed

Dec 12 2018, 12:47pm

IMAGE: SHUTTERSTOCK

A new **scientific study** supported by the Dutch Ministry of Infrastructure warns that the renewable energy industry could be about to face a fundamental obstacle: shortages in the supply of rare metals.

To meet greenhouse gas emission reduction targets under the Paris Agreement, renewable energy production has to scale up fast. This means that global production of several rare earth minerals used in solar panels and wind turbines—especially neodymium, terbium, indium, dysprosium, and praseodymium—must grow twelvefold by 2050.

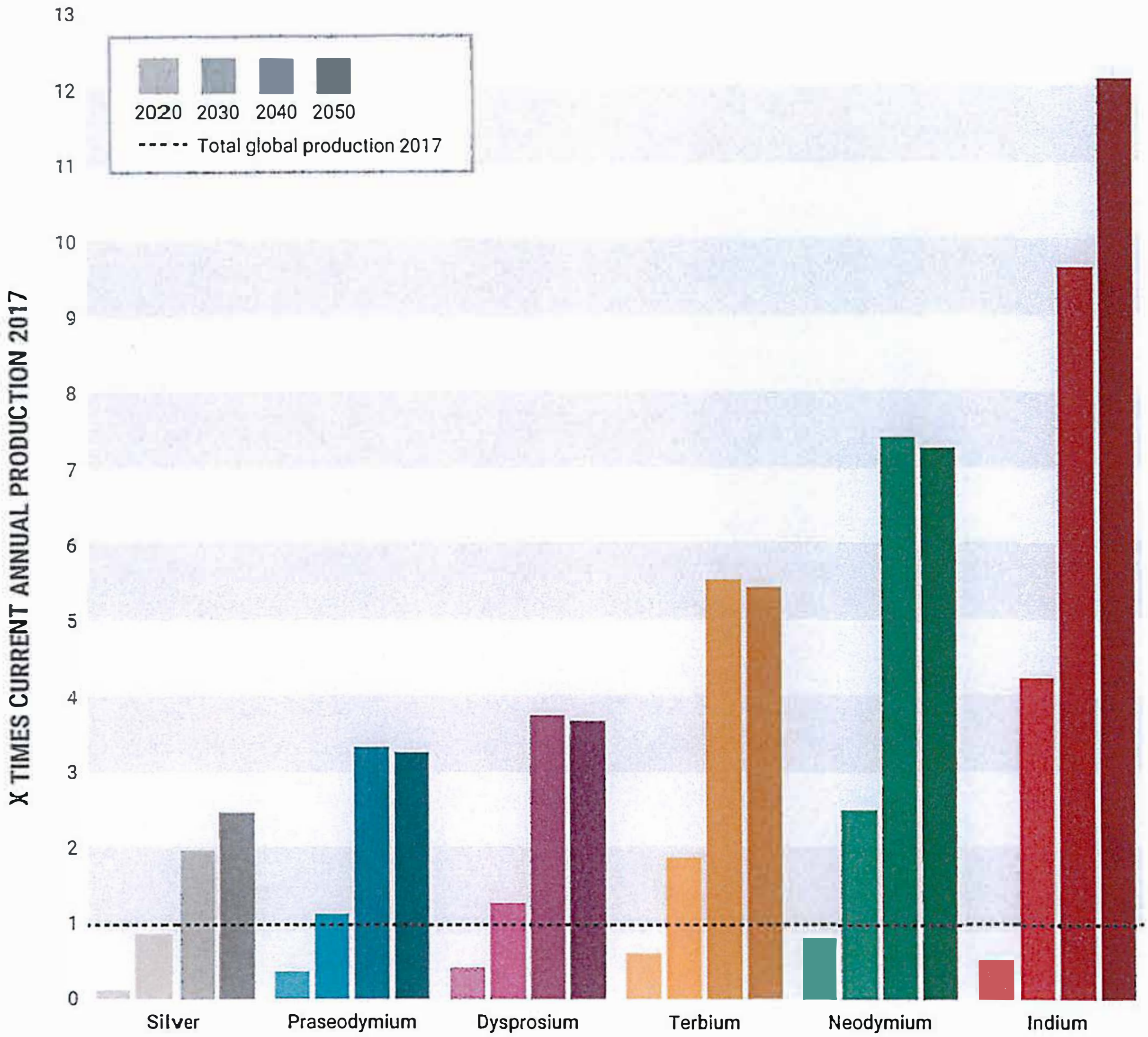

FIG 1. GRAPH DEPICTING GLOBAL CRITICAL METAL DEMAND FOR WIND AND SOLAR PANELS, BETWEEN 2020 AND 2050, COMPARED WITH THE 2017 LEVEL OF ANNUAL METAL PRODUCTION (2017 = 1).

But according to the new study by Dutch energy systems company Metabolic, the "current global supply of several critical metals is insufficient to transition to a renewable energy system."

The study focuses on demand for rare metals in the Netherlands and extrapolates this to develop a picture of how global trends are likely to develop.

"If the rest of the world would develop renewable electricity capacity at a comparable pace with the Netherlands, a considerable shortage would arise," the study finds. This doesn't include other applications of rare earth metals in other electronics industries (rare earth metals are widely used in smartphones, for example). "When other applications (such as electric vehicles) are also taken into consideration, the required amount of certain metals would further increase."

Demand for rare metals is pitched to rise exponentially across the world, and not just due to renewables. Demand is most evident in "consumer electronics, military applications, and other technical equipment in industrial applications. The growth of the global middle class from 1 billion to 3 billion people will only further accelerate this growth."

But the study did not account for those other industries. This means the actual problem could be far more intractable. In 2017, a **study** in *Nature* found that a range of minerals essential for smartphones, laptops, electric cars and even copper wiring could face supply shortages in coming decades.

The other challenge is that rare metals mining is massively concentrated in just a few countries: particularly China, which dominates 80 percent of mining and nearly 95 percent of refining. Although Australia and Turkey are significant producers of specific metals (such as neodymium and boron respectively), Europe and the US are overwhelmingly dependent on China, which would be in a position to control global supply—a position that could be easily abused.

"There might be a certain moment when they prioritize their own renewable production over others—they have been taking a strategic position in getting all the technological expertise and data around this," said lead author Pieter van Exter in a statement.

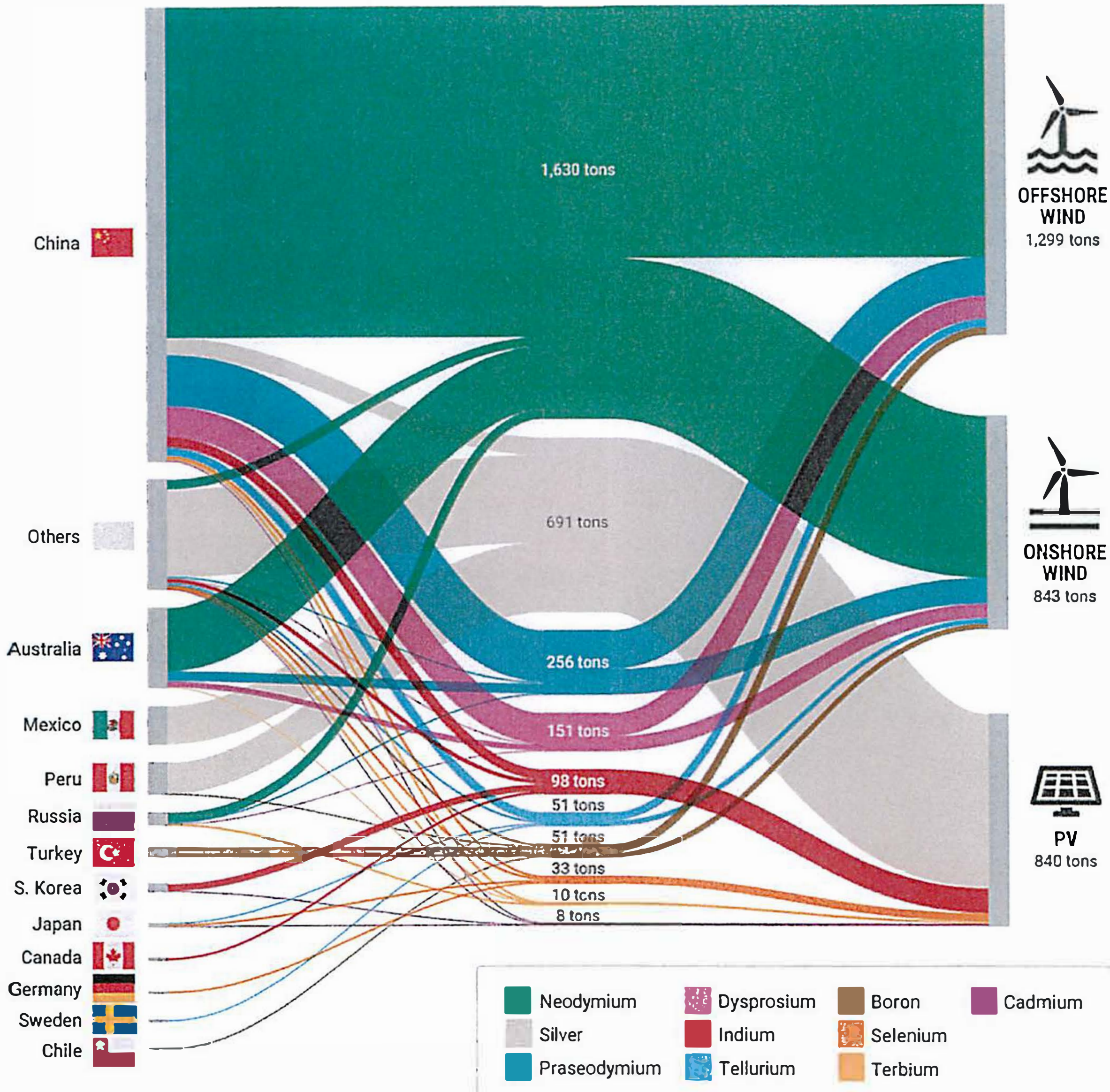

FIG 2. THE CUMULATIVE DEMAND FOR A SELECTION OF CRITICAL METALS UNTIL 2030, SHOWING THE COUNTRY OF ORIGIN (LEFT) AND TECHNOLOGY (RIGHT)

The good news is that ample identified reserves for the renewable energy transition, at least, do exist. The key challenge is lead-times. It takes large capital investments and between 10-20 years to open new mines.

One solution is to find viable substitutions for rare metals. This holds some promise, but could also shift the burden to other metals. Another solution is for Europe and others to revitalise domestic mining industries using new technologies that can reduce their energy and water footprint. This could still be costly—and domestic reserves aren't ample enough to rival the likes of China.

The key is the 'circular economy,' a regenerative approach designed to minimise resource inputs and waste by implementing principles and methods of design, maintenance, repair and recycling. According to Metabolic founder Eva Gladek, "It is essential for us to manage materials in a circular fashion in order to ensure that we have enough for the technologies critical to a low-carbon future."

Currently, however, recycling rates for critical metals are at below 1 percent, and some rare earth metals aren't recycled at all. If that practice continues, critical supply bottlenecks will be inevitable: "Unless a circular strategy is implemented, the industry will remain completely reliant on mining for its raw material supply. To make recycling the dominant source of raw materials, very high recycling rates will be needed," the company said.

To succeed, the renewable energy industry needs to embrace the circular economy. If it doesn't, the report authors told me, "this could drastically delay the energy transition—a disruption which we cannot afford in the race against climate change."

TAGGED: TECH, MOTHERBOARD, CLIMATE CHANGE, IPHONES, RECYCLING, RARE EARTH METALS, WIND TURBINES, RENEWABLE ENERGY, SOLAR PANELS, RARE EARTH MINERALS

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A Scarcity of Rare Metals Is Hindering Green Technologies

A shortage of "rare earth" metals, used in everything from electric car batteries to solar panels to wind turbines, is hampering the growth of renewable energy technologies. Researchers are now working to find alternatives to these critical elements or better ways to recycle them.

BY NICOLA JONES • NOVEMBER 18, 2013

With the global push to reduce greenhouse gas emissions, it's ironic that several energy- or resource-saving technologies aren't being used to the fullest simply because we don't have enough raw materials to make them.

These bits of critical elements are bound for recycling at a Mitsubishi subsidiary in Japan. HARUYOSHI YAMAGUCHI/BLOOMBERG

For example, says Alex King, director of the new Critical Materials Institute, every wind farm has a few turbines standing idle because their fragile gearboxes have broken down. They can be fixed, of course, but that takes time – and meanwhile wind power isn't being gathered. Now you can make a more reliable wind turbine that doesn't need a gearbox at all, King points out, but you need a truckload of so-called "rare earth" metals to do it, and there simply isn't the supply. Likewise, we could all be using next-generation fluorescent light bulbs that are twice as efficient as the current standard. But when the U.S. Department of Energy (DOE) tried to make that switch in 2009, companies like General Electric cried foul: they wouldn't be able to get hold of enough rare earths to make the new bulbs.

The move toward new and better technologies – from smart phones to electric cars – means an ever-increasing demand for exotic metals that are scarce thanks to both geology and politics. Thin, cheap solar panels need tellurium, which makes up a scant 0.0000001 percent of the earth's crust, making it three times rarer than gold. High-performance batteries need lithium, which is only easily extracted from briny pools in the Andes.

In 2011, the average price of 'rare earth' metals shot up by as much as 750 percent.

Platinum, needed as a catalyst in fuel cells that turn hydrogen into energy, comes almost exclusively from South Africa.

Researchers and industry workers alike woke with a shock to the problems caused by these dodgy supply chains in 2011, when the average price of "rare earths" – including terbium and europium, used in fluorescent bulbs; and neodymium, used in the powerful magnets that help to drive wind turbines and electric engines – shot up by as much as 750 percent in a year. The problem was that China, which controlled 97 percent of global rare earth production, had clamped down on trade. A solution was brokered and the price shock faded, but the threat of future supply problems for rare earths and other so-called "critical elements" still looms.

That's why the Critical Materials Institute, located at the DOE's Ames Laboratory, was created. The institute opened in June, and the official ribbon-cutting was in September. Its mission is to predict which materials are going to become problems next, work to improve supply chains, and try to invent alternative materials that don't need so many critical elements in the first place. The institute is one of a handful of organizations worldwide trying to tackle the problem of critical elements, which organizations like the American Physical Society have been calling attention to for years. "It's a hot topic in Europe right now," says Olivier Vidal, coordinator of a European Commission project called ERA-MIN – one of a handful of European initiatives that are now ramping up.

"It's really urgent," says King. "We're facing real challenges today – we need solutions tomorrow, not the day after."

Despite the high cost and high demand of metals critical for energy technologies, very little of this metal is recycled: In 2009, it was estimated that less than one percent of rare earth metals was recovered. Ruediger Kuehr, head of the Solving the E-waste Problem (StEP) initiative in Bonn, says that 49 million tons of e-waste are produced each year, from cell phones to refrigerators. Of that, perhaps 10 percent is recycled. It's ridiculous to simply throw so much valuable material away, says Diran Apelian, founding director of the Metal Processing Institute in Worcester, Massachusetts. "There's something like 32 tons of gold in all the world's cell phones," says Apelian. "There's a huge goldmine in our urban landfills."

> A Belgian company now recycles 350,000 tons of e-waste a year, including photovoltaic cells.

Getting the metals out of modern technology is a pain, since they are incorporated in tiny amounts into increasingly-complex devices. A circa-2000 cell phone used about two dozen elements; a modern smart phone uses more than 60. "We're making things more difficult for ourselves," says King. Despite the relatively high concentrations of rare earths in technology, he says, it's actually chemically easier to separate them from the surrounding material in simple rocks than in complicated phones.

But it is possible. The Brussels-based company Umicore is at the forefront of recycling technologies for critical metals, says King. At its site in Hoboken, Belgium, the company annually recycles about 350,000 tons of e-waste, including photovoltaic cells and computer circuit boards, to recover metals including tellurium. In 2011, Umicore started a venture to recycle rare earths from rechargeable metal hydride batteries (there's about a gram of rare earths in a AAA battery) at its Antwerp site, in partnership with the French company Solvay. Likewise, the Japanese car-company Honda announced this March that it has developed its own in-house recycling program for metal hydride batteries – which the company plans to test using the cars damaged by Japan's 2011 quake and tsunami. The Critical Materials Institute is developing a method that involves melting old magnets in liquid magnesium to tease rare earths out. "When it comes to recycling, anything is possible," says Kuehr. "It's a question of whether it's economic."

One of the hardest steps in e-waste recycling is simply getting the battery or other critical-metal-rich components out of the larger device or machine. This is a menial but intricate task, which is often handed over to low-paid workers in places like China or Nigeria. In the Guiyu area of southern China, for example, more than 100,000 people work to take apart e-waste, boiling up circuit boards to remove the plastic and then leaching the metals with acid, at great risk to the environment and themselves. Uncontrolled burning leads to contaminated groundwater, and one study found elevated levels of lead in children living in Guiyu. Japan is at the forefront of efforts to automate these processes so they can be done economically and safely by machines, says King.

> The onus has to be put on the manufacturers to recover and recycle their own products, one researcher notes.

Even more important than technology, says Apelian, is policy and education. In a study of the U.S. recycling rates of about 20 products, from plastic to metal, the one with the highest rate of recovery is lead-acid batteries, used primarily in cars. Their recovery rate is 98 percent, compared to about 50 percent for aluminum cans. The reason, Apelian says, is because the government, worried about the lead, gives car companies a financial incentive to recycle the batteries themselves.

The onus, Apelian says, has to be put on the manufacturers to recover and recycle their own products, so they make them easier to re-use or break apart in the first place. "We need to manufacture for recovery. That's almost non-existent."

Recycling is perhaps the best route forward for elements where demand is expected to level off in the long run. Demand for terbium and europium, for example, will likely fade as fluorescent bulbs are eventually replaced with much smaller LEDs. But for other elements, like neodymium, this can't be the only solution. "Right now we need tiny amounts of neodymium, for the ear-buds of your smartphone," says King. "But for a high-performance wind turbine you need about two tons."

For elements where demand is expected to increase, one option is to open new mines. China currently dominates rare earth mining – in part, notes a 2011 American Physical Society report, because more relaxed environmental standards about land reclamation make it cheaper. But resources exist elsewhere. There are about 450 potential rare earth mines being looked at around the world, according to King. A few are fairly advanced. The rare-earth division of Mountain Pass mine in California reopened this year, after being driven out of business by China in 2002. Despite some initial disappointments in production capacity, King thinks that venture will succeed. Likewise, the Mount Weld mine for rare earths in Australia is ramping up. These efforts, among others, have reduced China's production share from 97 percent to about 90 percent in the past year or two, says King.

> One approach is to find alternative materials that don't need so many critical elements.

It can be difficult to develop economies of scale when dealing with materials only used in tiny amounts. Global demand for tellurium in 2009, for example, was just 200 metric tons. All of that came as a by-product from copper or gold mining. Though tellurium is extremely valuable at $145 per kilogram, the tiny amounts hardly make a blip in the profit sheets of these mining companies. "They have to be dragged into production kicking and screaming," says King.

Another option is to make the mining processes more efficient. For rare earths, says King, mining companies basically grind up the rock, throw it in water, and blow bubbles through it: The rare-earth-bearing minerals tend to float and can be skimmed off the top. But this only captures about 65 percent of the rare earths in an ore, says King. His institute is now using DOE supercomputers to search for molecules that might bind to the elements and help them to float. "If we can invent a fairy dust to sprinkle into the water to make that go from 65 percent to 75 percent, you instantly boost rare earth production without opening a new mine," says King. He hopes this strategy will succeed within a year or two.

MORE FROM YALE e360

Boom in Mining Rare Earths Poses Mounting Toxic Risks

The mining of rare earth metals, used in everything from smart phones to wind turbines, has long been dominated by China. But as mining spreads to countries like Malaysia and Brazil, scientists warn of the dangers of the toxic and radioactive waste their mining and processing generates.

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A final approach is to find alternative materials that don't need so many critical elements in the first place. This is a demanding task. "The rare earths are kind of magic," says King, in terms of their properties. They are a critical ingredient in magnets, for example, because of the way they wrangle the strong but unruly magnetic properties of iron – a task that no other element seems able to do. Research efforts attempting to make even stronger magnets without any rare earths are considered a long shot. But, says King, "We might not get them all out, but we can get the most expensive and rarest [rare earths] out."

King remains optimistic. Struggles with limited resources go way back, he notes. The Bronze Age, some 2,000 years ago, caused copper supplies to run dry. In response, King says, the ancients recycled bronze, looked for new mines, and spent 200 years optimizing the more-available but less-ideal alternative – iron – to do the same job. The solutions today are the same, though hopefully finding suitable replacements won't take so long. "It doesn't take us 200 years anymore," says King. "We're shooting for two."

Nicola Jones is a freelance journalist based in Pemberton, British Columbia, just outside of Vancouver. With a background in chemistry and oceanography, she writes about the physical sciences, most often for the journal *Nature*. She has also contributed to *Scientific American*, *Globe and Mail*, and *New Scientist* and serves as the science journalist in residence at the University of British Columbia. MORE →

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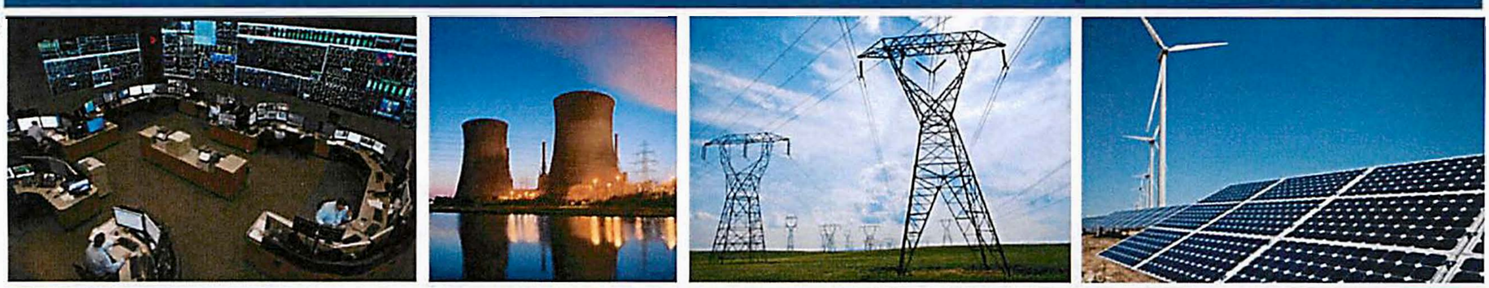
2016 Probabilistic Assessment

March, 2017

RELIABILITY | ACCOUNTABILITY



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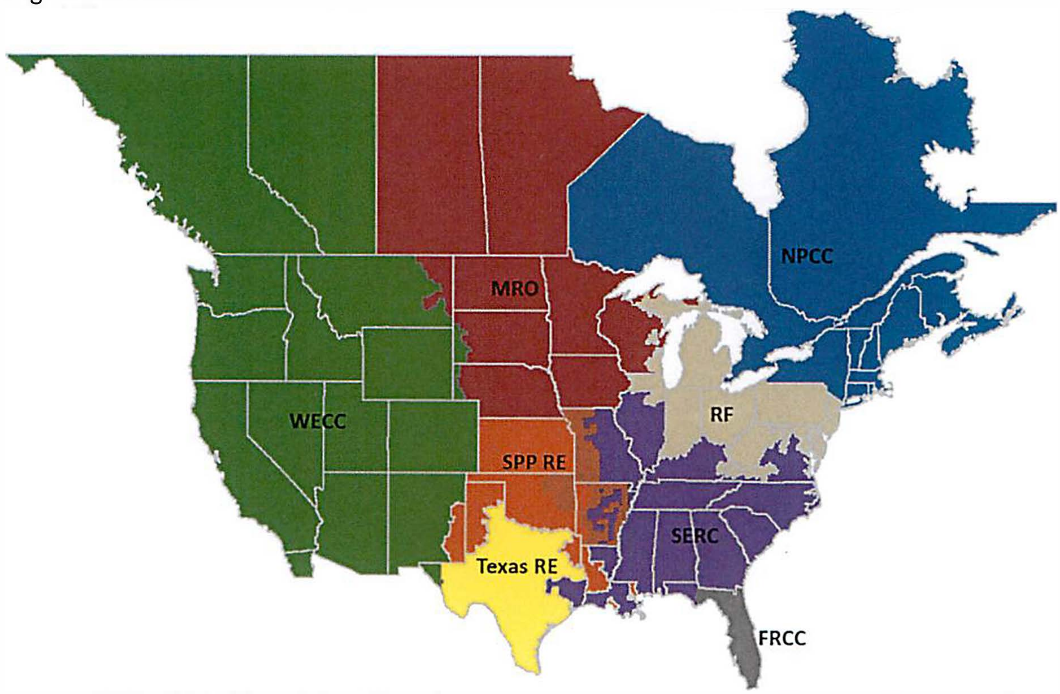
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council

FRCC

MRO – Midwest Reliability Organization

MISO
MRO-Manitoba Hydro
MRO-SaskPower

NPCC – Northeast Power Coordinating Council

NPCC-Maritimes
NPCC-New England
NPCC-New York
NPCC-Ontario
NPCC-Québec

RF – ReliabilityFirst

PJM

SERC – SERC Reliability Corporation

SERC-East
SERC-North
SERC-Southeast

SPP RE – Southwest Power Pool Regional Entity

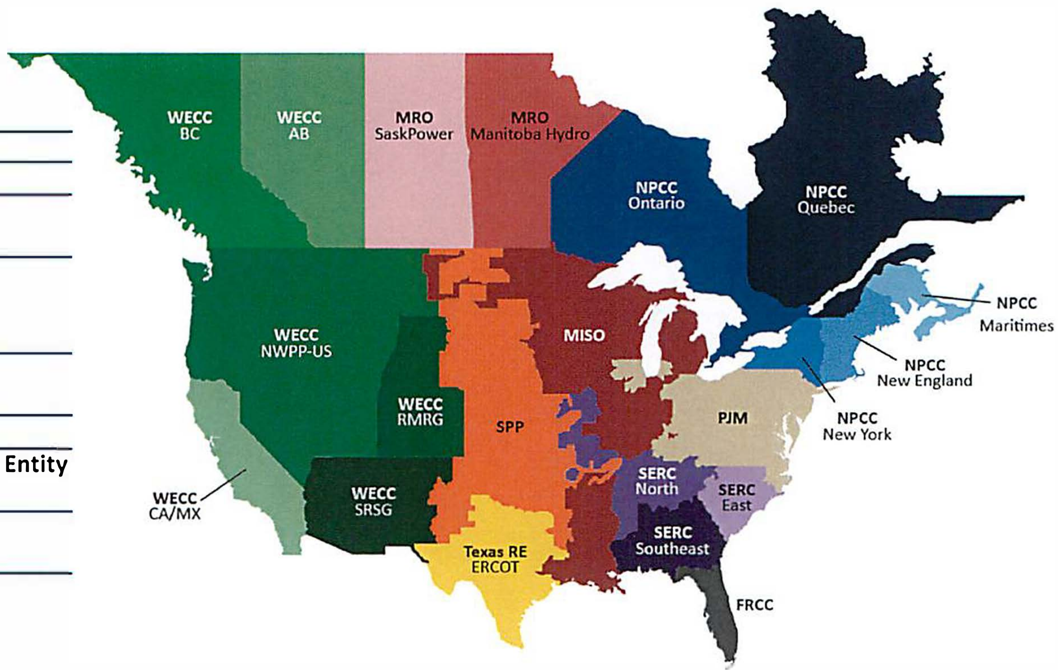
SPP

Texas RE – Texas Reliability Entity

Texas RE-ERCOT

WECC – Western Electricity Coordinating Council

WECC-CA/MX
WECC-NWPP-AB
WECC-NWPP-BC
WECC-NWPP-US
WECC-RMRG
WECC-SRSG



Executive Summary

The 2016 Probabilistic Assessment is an addendum to the *2016 Long-Term Reliability Assessment* (2016 LTRA) to provide a more comprehensive understanding of resource adequacy beyond the reserve margin analysis offered by the 2016 LTRA. A brief summary of this analysis has already been included in the 2016 LTRA.[1] This report contains a fuller set of the assessment results and additional description of the methods used in each of the Regions.

A probabilistic assessment offers a different approach for examining the complexity of the changing BPS that is necessary for identifying reliability issues and developing prompt industry actions to address them. Specifically, the objectives of this assessment are to:

- Calculate a complete and non-overlapping set of monthly and annual probabilistic reliability metrics across the NERC footprint
- Perform a resource adequacy assessment covering all hours (compared to only the peak demand hour of each season in the LTRA)
- Provide probabilistic reliability metrics, loss of load hours (LOLH), and expected unserved energy (EUE), for each NERC assessment area and convey a clear understanding of the reserve margin implications
- Compare results over time and between studies
- Examine the availability of non-firm capacity transfers between assessment areas
- Provide a composite generation and transmission assessment (resource adequacy), which considers the ability of load to receive power supplied by aggregate resources
- Calculate probabilistic reliability metrics under a sensitivity case with increased in load growth

This probabilistic assessment uses a similar process to the LTRA: The Reliability Assessment Subcommittee (RAS), at the direction of the PC, supports LTRA development. Specifically, NERC and the RAS performed a thorough peer review that leveraged the knowledge and experience of industry subject matter experts while providing a balance to ensure the validity of data and information provided by the Regions. Each assessment area section is peer reviewed by members from other Regions to achieve a comprehensive analysis that is verified by RAS in open meetings. The review process ensures the accuracy and completeness of the data and modeling provided by each Region. The probabilistic assessment uses a similar process.

NERC recognizes that a changing resource mix with significant increases in energy–limited resources, changes in off-peak demand, and other factors can have an effect on resource adequacy. As a result, NERC is incorporating more probabilistic approaches into this assessment and other ongoing analyses that will provide further insights into how to best establish adequate reserve margins amidst a BPS undergoing unprecedented changes. Historically, NERC has gauged resource adequacy through planning reserve margins which are a deterministic assessment metric. Planning reserve margins are a measure of available capacity over and above the capacity needed to meet normal (50/50) forecast peak demand.

As a result of the Probabilistic Analysis Improvement Task Force (PAITF) recommendations, monthly reporting of LOLH and EUE were added for this report.[2]

[1] 2016 Long-Term Reliability Assessment

[2] Probabilistic Assessment Improvement Task Force

The 2016 ProbA report includes a sensitivity case in which monthly and annual LOLH and EUE measures are calculated while increasing net energy for load (demand in all hours) by two percent for both 2018 and 2020 and increasing total internal demand (TID) by two percent in 2018 and by four percent in 2020. This sensitivity case is usually interpreted as the impact of increased load growth, but it can also be used to better understand the effect of increased retirements.

NERC has identified the following key findings:

- Most of the assessment areas showed no loss of load probability in either the base or sensitivity cases. This was expected with the high reserve margins in those areas as reported in the LTRA.
- Monthly LOLH and EUE statistics were reported for the first time this year. Monthly patterns are only available for the seven assessment areas with nonzero annual values. FRCC, MISO, NPCC-New England, and TRE-ERCOT show almost all of the LOLH in July and August as expected for these summer peaking utilities. FRCC and TRE-ERCOT only show useable statistics for the sensitivity case. Determining the precise reasons for monthly patterns is useful for resource planning and future probabilistic resource adequacy analysis.
- Monthly loss of load probabilities have been a very useful addition to the analysis and should be continued. As more variable resources come online, which may impact the viability of other resources, increased loss of load probability may be observed.
- The sensitivity case of two percent and four percent load increases was useful to find the point at which loss of load probabilities started increasing in some areas and to verify that the analyses were reacting as expected.
- Assessment area boundary changes can cause challenges in measuring changes from year to year and study to study. Most of the areas have remained the same as in the 2014 ProbA report. However, only two of the six areas in WECC are substantially the same as in the 2014 Report (i.e., CAMX & SRSG), and MAPP has been included in SPP for this report.
- Modeling for variable energy resources is increasingly important as these resources become a larger portion of the generating mix. Most areas are still modeling wind and especially solar as a flat load adjustment, varying by season. Probabilistic approaches should be used to represent the stochastic behavior of wind and solar as these resources increase penetration.
- Assessment areas are increasing the amount of both internal and external transmission modeling. Transmission modeling is very area specific and it may not be necessary to have multiple subareas modeled for wide-area analysis.
- Peer review for the probabilistic assessment analysis is largely methodology-based. Critical methodology review is needed as probabilistic approaches introduce increased complexity and relatively new assumptions.

Introduction

This report presents the third probabilistic resource adequacy assessment conducted as a complement to the Long-Term Reliability Assessment. Previous probabilistic analyses were run in conjunction with the 2012 and 2014 LTRAs. All assessments calculated loss of load hours (LOLH) and expected unserved energy (EUE) for the third and fifth years of the LTRA. This year's analysis calculates the probabilistic resources measures for 2018 and 2020.

As in the previous two probabilistic assessments, probabilistic analyses were conducted for all assessment areas within NERC. The LOLH, EUE, and reserve margins from the 2014 are included here to show trending between the 2016 and 2014 analyses.[3][4]

For 2016, some of the probabilistic assessment results included in the *2016 LTRA* and monthly LOLH and EUE reliability statistics were added to evaluate annual patterns of outages and further emphasize the objective of looking at reliability at all times of the year and not only seasonal peaks.

This report presents additional results, comparisons with the *2014 ProbA*, discussions, and details on the methodologies used in each of the assessment areas.

Background

In 2010, the Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) concluded that existing reliability models could be used to develop one common composite generation and transmission assessment of resource adequacy. The task force also noted the importance of having complete coverage of the North American BPS as well as the elimination of overlaps. As this premise is already adopted and executed annually in the LTRA, the approach for this probabilistic assessment follows suit. The assessment areas (i.e., Regions, Planning Coordinators (PCs), independent system operators (ISOs), and regional transmission organizations (RTOs)) used for this assessment are identical to those used for the LTRA.

The objectives of the probabilistic assessment are:

- Calculate a complete and non-overlapping set of monthly and annual probabilistic reliability metrics across the NERC footprint.
- Perform a resource adequacy assessment covering all hours (compared to only the peak demand hour of each season in the LTRA).
- Provide probabilistic reliability metrics, loss of load hours (LOLH) and expected unserved energy (EUE) for each NERC assessment area and convey a clear understanding of the reserve margin implications.
- Compare results over time and between studies.
- Examine the availability of non-firm capacity transfers between assessment areas.
- Provide a composite generation and transmission assessment (resource adequacy) that considers the ability of load to receive power supplied by aggregate resources.

In this effort to improve NERC's continuing probabilistic and deterministic assessments, the Probabilistic Assessment Improvement Task Force (PAITF) was formed in May of 2015 from members of the Planning Committee (PC), the Reliability Assessment Subcommittee (RAS), and selected observers from industry to identify improvement opportunities for NERC's Long-Term Reliability Assessment and complementary probabilistic analysis.

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[3] NERC 2012 Probabilistic Assessment Report

[4] NERC 2014 Probabilistic Assessment Report

PAITF developed two reports; the *NERC Probabilistic Assessment Improvement Plan* report published in December 2015, over which possible recommendations by PAITF were provided based on recent LTRA key findings for NERC core and proposed coordinated special probabilistic assessment reports. The second report of *NERC Technical Guideline Document* published in August of 2016 over which detailed probabilistic modeling guidelines and technical recommendations were presented that serve as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy. [5]

The PAITF defined five different probabilistic resource adequacy statistics that are widely used, summarized in the below table. Only LOLH and EUE are reported for all assessment areas.

Probabilistic Assessment Primary Measures
The Probabilistic Assessment reports two metrics—EUE and LOLH. These and other probabilistic metrics are defined below.
Expected Unserved Energy (EUE) This is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. The EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). The EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. Additionally, this measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load, etc.). Normalizing the EUE provides a measure relative to the size of a given assessment area. One example of calculating a Normalized EUE is defined as [(Expected Unserved Energy) / (Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.
Loss-of-Load Hours (LOLH) This is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.
Loss-of-Load Expectation (LOLE) This is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand. This is the original classic metric that is calculated using only the peak load of the day (or the daily peak variation curve). However, this metric is not being reported as part of this assessment. Currently some assessment areas also calculate the LOLE as the expected number of days per year when the available generation capacity is insufficient to serve the daily load demand (instead of the daily peak load) at least once during that day. Loss-of-Load Probability (LOLP) This is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.
Loss-of-Load Events (LOLEV) This is defined as the number of events in which some system load is not served in a given year. A LOLEV can last for one hour or for several continuous hours and can involve the loss of one or several hundred megawatts of load. Note that this is not a probability index but a frequency of occurrence index. LOLE, LOLEV, and LOLP are often used by assessment areas to define a target metric of reliability. The classic definition of reliability as one day in 10 years is a LOLP target and is often translated into an LOLE target of 0.1 day/year or LOLEV of 0.1 event/year. These metrics are not provided in this report to avoid potential conflicts with regional practices based on different methods.

The 2016 ProbA report is divided into two main sections and two appendices. The first section is an overview of the study, a comparison of the probabilistic analysis methods used in the various assessment areas, and overall conclusions and recommendations. The second section is a brief description of the analysis and presentation of the results for each assessment area. Appendix II: Detailed Probabilistic Modeling Table, is a per assessment area high-level modeling category description included in the 2016ProbA. Appendix II is available as another volume of

[5] Probabilistic Assessment Improvement Task Force - Technical Guideline Document

the report and is not included herein. Appendix III: Methods & Assumptions Table, is a brief tabular presentation of the main characteristics of the probabilistic modeling in each of the assessment areas. Appendix IV: ProbA Data Forms contains information are from each of the assessment areas. Appendix IV is available as supporting material and is not included herein. Appendix V: Detailed Reports by Regions or Assessment Area contains the full reports from each of the assessment areas from which the description was extracted. Appendix V is available as a second volume of the report and is not included herein.[6]

Overview of Results

The study methodologies used in each of the 10 probabilistic resource adequacy analyses are similar to the methodology used in 2014.[7,8] Significant changes include MISO adding internal transmission modeling and WECC switching from Monte Carlo uncertainty modeling in a production simulation model in 2014 to a multi-area convolution-based approach this year.

Most other areas continue to use Monte Carlo uncertainty modeling with a transportation or pipeline model for transmission. FRCC continues to use a convolution-based approach, and SPP uses a more detailed transmission representation modeling down to the 100 kV bus level.

Assessment Area Boundary Changes: Assessment area boundary changes can make the main interpretations of the probabilistic measure changes from year to year and study to study more difficult. Most of the areas have remained the same as in the 2014 report. However, only two of the six areas in WECC are substantially the same as in the 2014 report (CAMX & SRSG), and MAPP has been absorbed into SPP for this report.

Wind and Solar Modeling: Most areas are still modeling wind and especially solar as a flat load adjustment varying by season. SERC, WECC, and ERCOT model wind correlated to the load data on an hourly basis and notice variations in the wind contribution on peak by modeling multiple load/wind years. To analyze uncertain contributions of wind in a study that uses a single typical load shape, NPCC-Ontario samples from a number of possible wind outputs on each draw, creating a similar effect to random outage rates with thermal generation. Assessment areas with large wind capacities should adopt approaches that incorporate a range of values for the contribution of wind. For areas with small amounts of wind, a more sophisticated modeling of wind would produce minimal benefit. As wind grows in capacity so should the modeling complexity used.

WECC and ERCOT model solar explicitly correlated to the load data across multiple years. As with wind, areas with large amounts of solar capacity will have to increase the detail with which they model solar. Solar is often behind-the-meter complicating modeling and reducing information available.

Internal and External Transmission Modeling: Generally, assessment areas are increasing the amount of both internal and external transmission modeling. WECC, SERC, NPCC, and PJM now all have detailed modeling of transmission, load, and generation even in neighboring assessment areas. SPP has the most detailed transmission modeling both internally and externally, modeling down to the 100 kV level. MISO has added internal transmission modeling this year with a hub & spoke approach. In contrast, ERCOT has reduced to a one-area internal representation from a two-area model. They found adding the additional internal subarea did not significantly impact reliability. Smaller assessment areas model only the transmission between them and other assessment areas. This indicates that transmission modeling is very area specific and it may not be necessary to have multiple subareas modeled.

[6] Appendices will be available at NERC Reliability Assessment Page, http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[7] NERC Reliability Assessment Guidebook
[8] Methods To Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning

Data Modeling: There are no major reported differences between the data used in the *2016 ProbA* and the *2016 LTRA*. MISO is showing data differences due to the treatment of transmission in the modeling but there is no fundamental difference in the underlying system modeled.

Monthly Reporting of Reliability Statistics

Monthly LOLH and EUE statistics were reported for the first time this year. Monthly patterns are only available for the seven assessment areas with nonzero annual values. FRCC, MISO, NPCC-New England, and Texas RE-ERCOT TRE-ERCOT show almost all of the LOLH in July and August as expected for these summer peaking utilities. FRCC and TRE-ERCOT only show useable statistics for the sensitivity case.

SERC-E, though it is a southern area is almost dual peaking with winter peak only a couple of percent less than the summer peak. This is reflected in the monthly LOLH; winter (Dec. to Jan.) accounts for 85 percent to 90 percent of the LOLH in the base case. In the sensitivity case where the system is more stressed, the LOLH is more evenly spread between the two seasons, only 60 percent to 70 percent of LOLH is in the winter. There is insufficient detail in the SERC report to understand why this pattern occurs. It would be quite useful for SERC and all NERC areas to understand why this pattern is occurring.

The other two assessment areas with nonzero statistics are winter peaking, Manitoba Hydro and SaskPower. Both show a concentration of outage probability in the winter as expected but also other interesting characteristics. Manitoba shows the highest likelihood in March and November rather than right at the winter peak. Manitoba does not explain why this occurs.

SaskPower reports a small amount of LOLH in all months with a concentration toward the peak winter months. Note the LOLH spike in October for 2016 that may be due to maintenance.

In summary, of six areas with nonzero monthly values, half are showing interesting monthly patterns where the loss of load likelihood is often outside of the traditional peak period. Determining the precise reasons for these patterns might be useful to the areas with resource planning and future probabilistic resource adequacy analysis. Monthly reporting has been a very useful addition to the analysis.

Sensitivity Case

For each probabilistic assessment, an additional sensitivity case is run for each Region. This year, the additional case is a two percent increase of energy in both 2018 and 2020. Peak demand was increased by two percent in 2018 and by four percent in 2020. This sensitivity is generally interpreted as the effect of an increase in load growth but could also provide insight related to additional resource retirements.

Most of the assessment areas showed no loss of load probability in either the base or sensitivity case. This was not unexpected with the high reserve margins in those areas as reported in the LTRA.

FRCC and Texas-RE showed nonzero statistics only for the sensitivity case. In these areas, the sensitivity case served as a demonstration that the analysis produces the expected results.

MISO, Manitoba Hydro, SaskPower, NPCC-New England, NPCC-New York and SERC-East showed values for both the base and sensitivity cases and provided useful insights on the sensitivity of the results to either increased load or increased retirements.

Individual Assessment Area Results

Most Regions are showing zero LOLH and EUE in both 2018 and 2020 in this report as was the case in the *2014 ProbA*. This reflects large reserve margins in most Regions.

MISO as was evident from the reserve margins reported in the LTRA, is getting close to its resource adequacy targets in 2020. The LOLH and EUE also reflect this. Moving from 2018 to 2020 the LOLH increases by a factor of four. When the additional four percentage load increase is included for the sensitivity, LOLH increases a further 10 times. This is due to the exponential nature of the LOLH and EUE. These are more sensitive indicators than reserve margin.

SERC is divided into three assessment areas. Only SERC-E shows any significant LOLH or EUE. This is expected from the low reserve margins already reported in the LTRA. What is most interesting here is the monthly pattern of the loss of load. It is scattered throughout the year rather than being concentrated in the summer or winter. January is the month with the highest unsupplied load even though SERC-E is a summer peaking area. This illustrates the benefit of looking at the whole year for reliability calculations rather than just at the peak season.

Texas RE-ERCOT is showing zero base case LOLH and EUE in this 2016 ProbA analysis which is much lower than in the 2014 ProbA. This is expected due to the much larger reserve margins now. The four percent plus load sensitivity does cause significant LOLH as expected as the reserve margin falls to near the reference margin. Here the sensitivity has served as an illustration that the analysis is providing useful results. As expected, loss of load expectation is concentrated in the peak summer months.

WECC is showing zero loss of load probability for all regions for the base case which could reflect the higher reserve margins as reported in the LTRA. However, for the 2020 sensitivity case where load is increased by four percent, LTRA reserve margins are close to the reference margin for WECC-CAMX and WECC SRSG yet there is still zero loss of load expectation due to a large amount of interconnection support.

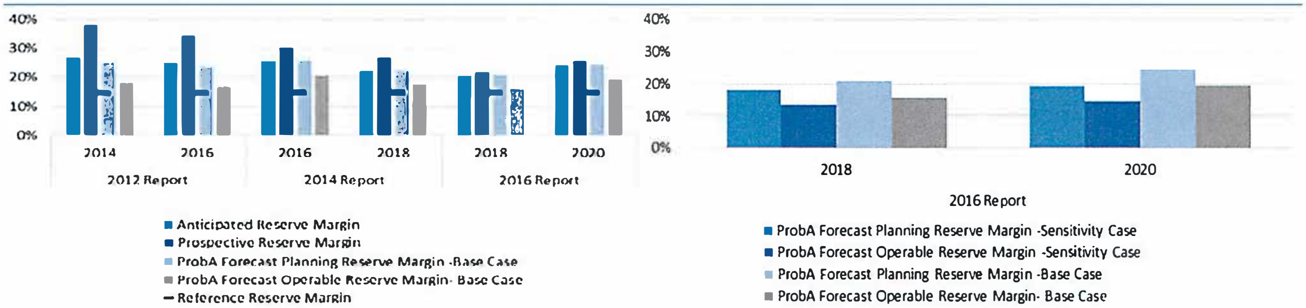
MRO-SaskPower is showing higher loss of load expectation in 2018 compared to the 2014 ProbA report. This is to be expected from the lower reserve margin this year. Reliability increases significantly with new generation coming on line. Even though it is a winter peaking system loss of load expectation occurs in all months showing the value of looking beyond the peak period for reliability analysis.

NPCC-New England is showing a reliability pattern typical of assessment areas with a market structure for capacity. The 2014 ProbA shows higher loss of load expectation which has come down in the 2016 ProbA as resources have entered the market increasing the reserve margin. In this report the out, 2020, year is again showing a lower reserve margin and higher loss of load expectation which are expected to improve by the time the 2018 ProbA is run. With the four percent plus sensitivity in 2020 the reserve margin drops below and the loss of load expectation rises as expected. This provides some assurance the model is reacting as expected.

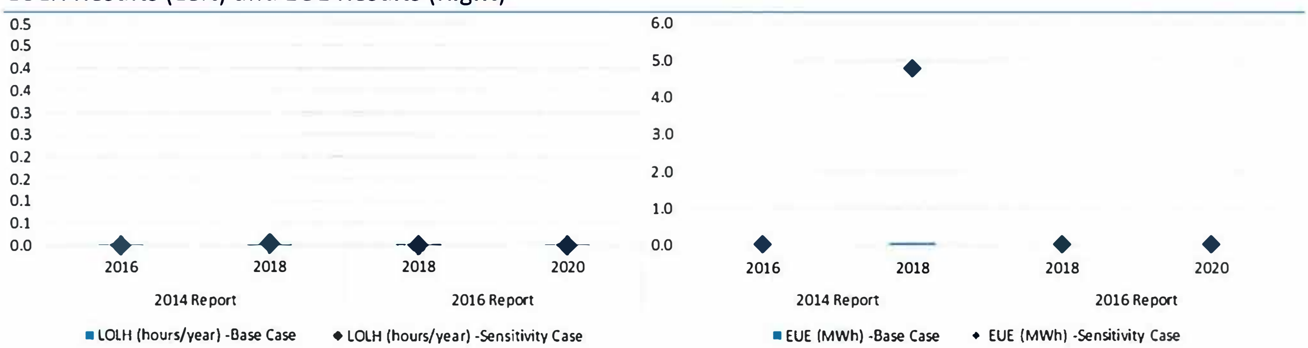
FRCC

The Florida Reliability Coordinating Council's (FRCC) membership includes 30 Regional Entity Division members and 23 Member Services Division members composed of investor-owned utilities (IOUs), cooperative systems, municipal utilities, power marketers, and independent power producers. FRCC is divided into 10 Balancing Authorities with 47 registered entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards. The Region contains a population of over 16 million people and has a geographic coverage of about 50,000 square miles over Florida.

Base Case Reserve Margins (Left) and Sensitivity Case Reserve Margins (Right)



LOLH Results (Left) and EUE Results (Right)



FRCC used the Tie Line and Generation Reliability (TIGER) program in this assessment. The simulation is performed for 500 iterations to determine the average LOLH and EUE metrics. There are minimal differences between the data reported in the *2016 LTRA* and the data used in the simulation.

The load variation enhancement to TIGER incorporated a random draw simulation (Monte Carlo) of 500 draws from variations of plus or minus two standard deviations that were developed for each monthly peak for each year of the study based on the weather, population growth, and economic variability. Unplanned outages were also factored in using a similar random draw of a range of unplanned outages with a variation of plus or minus two standard deviations. Behind-the-meter generation and associated loads are accounted for and netted out within FRCC load forecasts.

The study model assumes that all firm capacity resources are deliverable within the FRCC Region based on the results of detailed regional transmission studies. For the study, FRCC was modeled as an isolated area with no interconnections with other areas, except for firm imports.

The foundation of the forecasted chronological load model was developed through 10 years of actual hourly loads collected from all FRCC entities. The aggregation was adjusted for the removal of double-counted load and the addition of any controllable Demand Response (DR) that was exercised in order to obtain the true historical FRCC system NonCoincident peak demands. Weather normalization was applied to this dataset for some summer and winter seasons to remove abnormal variations in demand caused by unusual weather conditions (e.g., high frequencies of hurricane activity, prolonged cold weather fronts, or unusually warm summers).

The FRCC typically accounts for controllable DR as a load/demand reducing resource. Controllable DR was reported on a seasonal basis in the *2016 LTRA* document, but modeled on a monthly basis in this 2016 probabilistic analysis. As a result, there are small differences in the DR values between the LTRA and the simulation data

Generation capacity for both this study and the LTRA document is based on the seasonal net capability of each unit. FRCC entities consider all future capacity resources as "Planned". New generation and capacity re-ratings have been incorporated into the seasonal capacities. There are no jointly-owned units within the FRCC that share capacity with another metric reporting area. These sales have firm transmission service to ensure deliverability in the SERC Region.

Capacity purchases into the FRCC Region averaged 500 MW during the summer and winter seasons for the years studied and there is also approximately 830 MW of FRCC-owned capacity located outside the FRCC Region.
Two types of variable resources were included in this study, specifically, hydroelectric generation and photovoltaics (PV) assets, with only the minimum firm capacity of such units included as firm resources so that any variability in unit capacity was removed. All traditional dispatchable capacity was modeled as firm capacity available to serve load.

Although no transmission constraints are included in this study, regional transmission assessments indicate that transmission capability within the FRCC Region is expected to be adequate to supply firm customer demand, assuming planned firm transmission service under normal conditions and single contingency events.

There are no differences between the Reserve Margin reported in the LTRA and ProbA Base Case.

The 2018 year was studied in both the 2014 and the 2016 ProbA to evaluate any changes or trends. The 2014 ProbA base case analysis resulted in a EUE of 0.070 MWh and an LOLH of 0.0002 hours/year. The results from the 2016 ProbA base case analysis showed a negligible decrease.

Base Case Study

The base case assumes no Emergency Operating Procedures (EOP). Thus, the base case assumes conditions where all available resources are committed to meet firm load. Nonzero loss of load values are projected only during the summer season, with the highest loss of load values estimated in August. Reserve Margins for the study years are well above the NERC Reference Margin of 15 percent resulting in low LOLH and EUE values. EUE was 0.0013 MWh (2018) and 0.0002 MWh (2020). Projected loss of load only occurred during the summer season.

Sensitivity Case Study

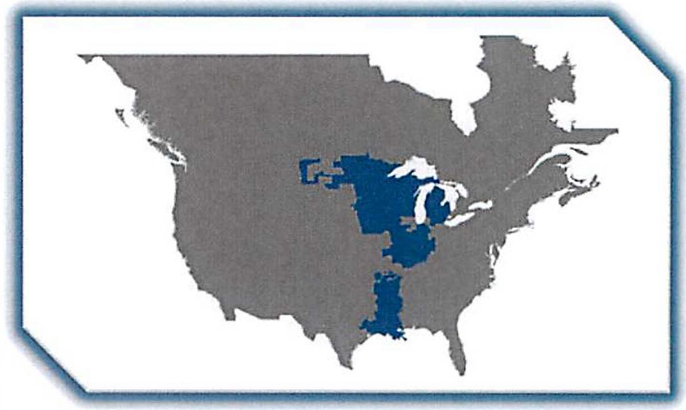
In order to perform the sensitivity case, a new hourly load file was created. For the 2018 study, every hour of the 2018 hourly load data was increased by 2 percent. For the 2020 study, the summer and winter peak hour was increased by 4 percent and the rest of the hours were increased by 2 percent. With the increase of load in the sensitivity case, Reserve Margins remain above the NERC Reference Margin of 15 percent and the EUE increased slightly from the base case to 0.0493 MWh (2018) and 0.0333 MWh (2020). Similar to the base case, nonzero loss of load values are projected only during the summer season with highest values in August.

Monthly Reliability Measures

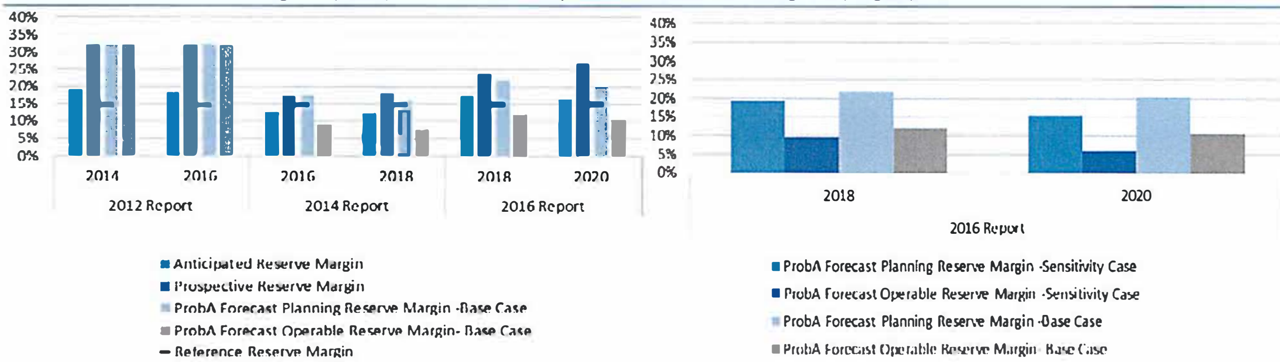
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar	0.000	0	0.000	0	0.000	0	0.000	0
Apr	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun	0.000	0	0.000	0	0.000	0	0.000	0
Jul	0.000	0	0.000	0	0.000	0	0.000	0
Aug	0.001	0	0.000	0	0.000	0	0.000	0
Sep	0.000	0	0.000	0	0.000	0	0.000	0
Oct	0.000	0	0.000	0	0.000	0	0.000	0
Nov	0.000	0	0.000	0	0.000	0	0.000	0
Dec	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.001**	**0**	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**

MISO

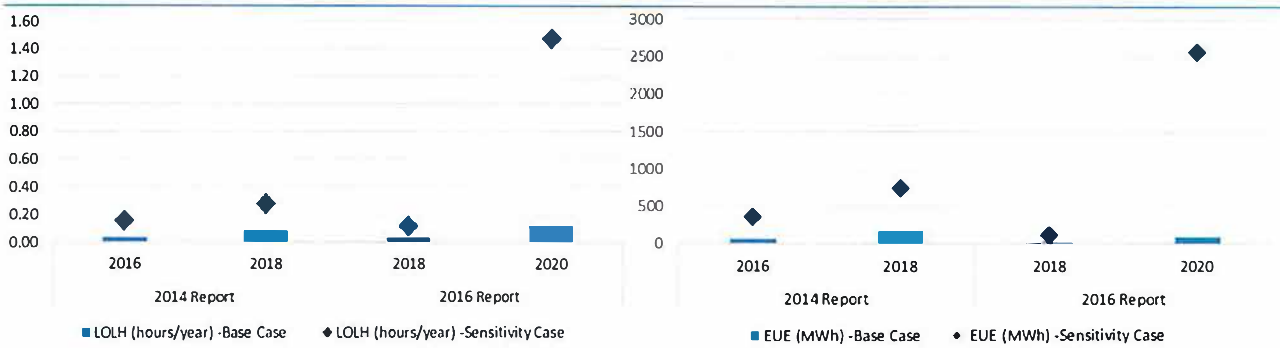
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authorities and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three NERC Regions, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.



Base Case Reserve Margins (Left) and Sensitivity Case Reserve Margins (Right)



LOLH Results (Left) and EUE Results (Right)



For this analysis MISO's 10 Local Resource Zones were modeled with their respective load and generation. The 10 zones were modeled with their respective import and export limits to model the entire MISO region. External firm and nonfirm support were also modeled. The 2016 Probabilistic Assessment was performed at NERC's request as a complement to the Long-Term Reliability Assessment by providing additional probabilistic statistics of loss of load hours (LOLH) and expected unserved energy (EUE) for the years 2018 and 2020. The annual Planning Reserve Margin (PRM) study that MISO conducts determines a PRM such that all available resources are committed to meet firm load without any remaining to respond to outages and contingencies. The Base Case for the 2016 Probabilistic Assessment was run in the same manner and no resources were held aside.

The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit which reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation produces an increase for the ProbA Forecast Planning Reserve Margin.

Assessment transmission is modeled based on MISO's Local Resource Zones capacity import and capacity export limit. . Within GE MARS this was modeled as a hub and spoke topology. External to the MISO system, transmission constraints are determined by analysis on historical high observed summer Network Scheduled Interchange (NSI) as well as resource availability. MISO ties and interfaces with the external system are not explicitly modeled but are contained in the amount of external firm and non-firm support modeled. MISO connects each Local Resource Zone to a central hub with infinite ties and models each LRZ with its own LFU.

The 2016 Probabilistic Assessment model included a constant 2,331 MW of external non-firm support for assistance to MISO in a time of need. This non-firm support amount is based off of historical probabilistic resource availability analysis as well historical Net Scheduled Interchange (NSI) data.

Firm Imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports.
Firm exports from MISO to external areas were also included in the analysis. Any export was decremented from the capacity available to MISO.

These non-coincident MISO peak load forecast values from the LSEs were applied to individual historic 2005 and 2006 load shapes and aggregated to form the MISO hourly load models and MISO coincident load peak created for this assessment. The historic years 2005 (MISO North/Central) & 2006 (MISO South) were chosen because they represent a typical load pattern year for MISO.

Load Forecast Uncertainty (LFU), a standard deviation statistical coefficient, is applied to a base 50/50 load forecast to represent the various probabilistic load levels. MISO back-calculated the system wide LFU equivalent to MISO's current zonal methodology to be about 3.8 percent.

Behind-the-Meter generation is modeled as a generation resource. MISO models each behind-the-meter generator as any other thermal generating unit with a monthly capacity and a forced outage rate.

Direct Control Load Management and Interruptible Demand type of demand-response were explicitly included in the MARS model created for this assessment as energy-limited resources. These demand resources are implemented in the MARS simulation before accumulating LOLE or shedding of firm load. The LTRA utilizes these resources as a load modifier.

The LTRA deterministic reserve margins decrement the capacity constrained within MISO south due to the 2,500 MW limit which reflects a decrease in reserve margin. The constraint was explicitly modeled for the probabilistic analysis and determined if sufficient capacity was available to transfer from south to north and vice versa. The modeling of this limitation produces an increase for the ProbA Forecast Planning Reserve Margin.

Previous results in the 2014 Probabilistic Assessment resulted in 182.2 MWh EUE and 0.09 Hours/year LOLH. The results from this year's analysis resulted in a slight decrease for 2018 when compared to the analysis completed in the 2014 Probabilistic Assessment.

Base Case Study

- The bulk of the EUE and LOLH are accumulated in the summer peaking months with some off peak risk.
- Increasing loss of load statistics expected with decreasing reserve margins.

Sensitivity Case Study

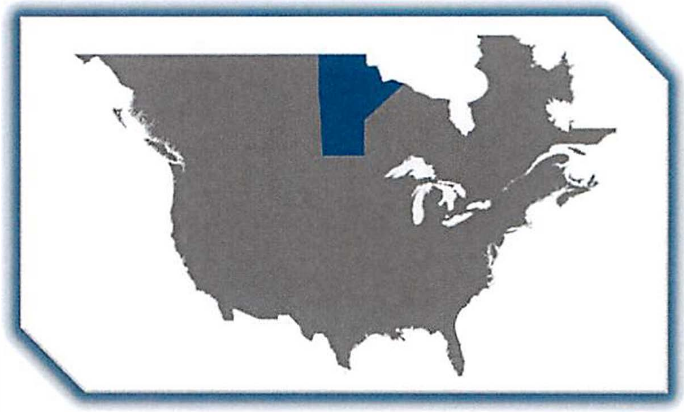
The sensitivity was modeled as a demand increase, for MISO it is more representable to think of it as a good proxy for increased retirement risk along with risk of increased load forecasts. The 2018 2 percent increase is equal to 2,565 MW increase and the 2020 4 percent increase is equal to a 5,203 MW increase. i.e. the 2018 sensitivity case could be a good proxy for increased retirement and load forecast increases that would lower our reserve margin by 2,565 MW.

Monthly Reliability Measures

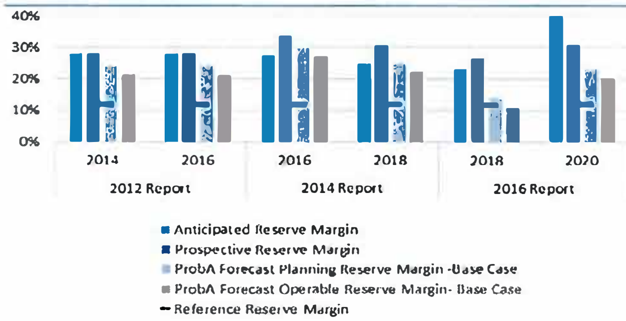
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar	0.000	0	0.000	0	0.000	0	0.000	0
Apr	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.001	0	0.000	0	0.012	4
Jun	0.000	0	0.016	5	0.001	0	0.024	9
Jul	0.027	14	0.065	39	0.082	66	0.704	815
Aug	0.006	4	0.041	51	0.036	48	0.727	1736
Sep	0.000	0	0.000	0	0.000	0	0.003	1
Oct	0.000	0	0.002	0	0.000	0	0.004	1
Nov	0.000	0	0.000	0	0.000	0	0.000	0
Dec	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.033**	**18**	**0.125**	**96**	**0.119**	**114**	**1.474**	**2566**

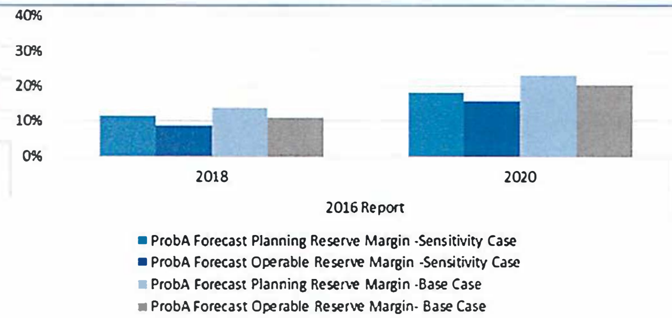
MRO –Manitoba Hydro

Manitoba Hydro is a Provincial Crown Corporation providing electricity to 561,869 customers throughout Manitoba and natural gas service to 274,817 customers in various communities throughout southern Manitoba. The province of Manitoba is 250,946 square miles. Manitoba Hydro is winter peaking. No change in the footprint area is expected during the assessment period. Manitoba Hydro is its own Planning coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of the MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

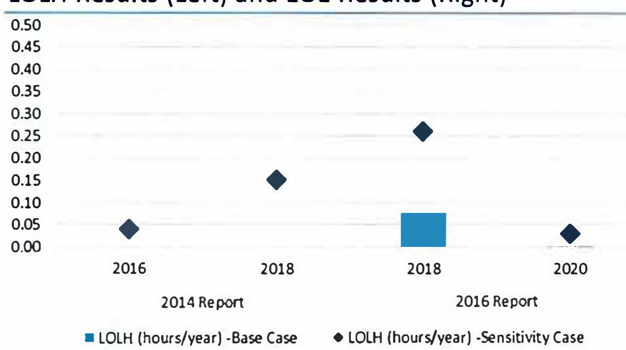


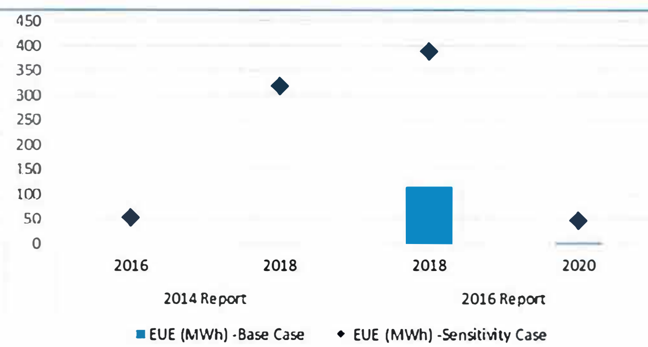
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)





The probabilistic assessment was conducted using the Multi-Area Reliability Simulation (MARS) program developed by the General Electric Company (GE). The reliability indices of the annual loss of load hours (LOLH) and the Expected Un-served Energy (EUE) for 2018 and 2020 were calculated considering different types of generating units (thermal, hydro and wind), firm capacity contractual sales and purchases, nonfirm external assistances, interface transmission constraints, peak load, load variations, load forecast uncertainty and demand side management programs.

The load model used in this assessment was obtained from the most recent Manitoba 50/50 peak load forecast for 2015/2016-2035/2036. The expected demand and the net energy forecast used in this assessment are the same as those numbers reported in the MH 2016 LTRA submittal to NERC. The 8760 point hourly load records of a typical year were used to model the annual load curve shape. The simulation software automatically modifies the input hourly load profile to meet the specified peak load and energy.

Manitoba is anticipating approximately 195 MW and 369 MW energy efficiency and conservation programs respectively for 2018 and 2020. These demand response programs were modeled as a simple load modifier with a flat profile on a weekly base.

The load forecast uncertainty (LFU) is considered in the assessment for both reporting years in both the base and scenario cases in order to capture uncertainties associated with weather, economic cycle, and forecast trend. It is assumed that the annual LFU is normally distributed with a 5 percent standard deviation in this assessment.

An expected hydraulic generation addition of 630 MW at Keeyask beginning in 2019 and the retirement of a 95 MW thermal capacity (Brandon Unit #5) in 2019 are modeled in this assessment. Because of the significance of hydro generation in Manitoba Hydro, Manitoba Hydro modeled multiple hydro conditions in the analysis representing average water condition, middle lower end of the flow and an extreme drought of water availability year.

Thermal units represent less than 10 percent of total installed capacity and they are assumed non-energy limited resource in this assessment. Outage statistics for the years of 2009-2013 inclusive was used to determine the forced outage rate and average forced outage duration of each thermal unit. Planned outages on thermal units are modeled by removing the unit from service for the specified periods of time. The simulation program schedules the planned outages for thermal units.

Two wind farms with 120 MW and 138 MW name plate capacity were modeled for both years of 2018 and 2020. In this study, wind generation at each site was modeled as an equivalent generating unit using a capacity credit or accredited capacity value determined based on the methodology proposed by Manitoba Hydro for long term capacity planning. The capacity credit of each wind farm is determined using actual historical data. Two seasonal accredited values for wind farms, one for the defined summer period and one for the defined winter period, are determined. The wind generation during the winter planning season (November-April) is accredited at 20 percent of the maximum wind generation capability, based on a peak period analysis of 2007-2015 data for top 8 daily coincident winter peak Manitoba load values per year utilizing the 70th percentile of hourly production values

Internal transmission for Manitoba is assumed to be 100 percent reliable. The transmission between Manitoba and MISO is modeled with interface transfer limits. The interface consists of two ties: one from Manitoba to MISO (export) and the other is from MISO to Manitoba (import). The interface limits for import (700 MW) and export (2175 MW) are determined based on steady-state and transient stability analyses.

The external system was modeled in the same detail as the Manitoba system rather than a simple equivalent model. It is assumed in this study that potential assistance from MISO is based on the MISO anticipated reserve margins for 2018 and 2020 planning years.

Two scenarios were also modeled by changing some of the parameters and the LOLH and EUE for these scenarios are reported.

The LOLH and EUE values obtained in the 2014 Probabilistic Assessment were zero. The nonzero LOLH and EUE values were obtained for both the base and scenario cases in 2016 probabilistic assessment. The slight increase in the reliability indices was mainly due to the changes in modeling assumptions. The following specific changes were made in 2016 assessment as compared to 2014 assessment:

(1) Multiple flow conditions including an extreme drought scenario are modeled and the indices calculated are weighted averages of the indices obtained for different water conditions.

(2) Increased standard deviation of the 7-step load forecast uncertainty from 4 percent to 5 percent.

Base Case Study

For 2018 base case, small values of EUE and LOLH are observed due to relatively less reserve margin. For 2020 base case, the reserve margin is increased significantly due to the expected addition of a new generating station and therefore the LOLH and EUE are virtually zero. Loss of load events occur during the winter season and the highest contribution to loss of load is from the winter month of November as Manitoba Hydro is a winter-peaking system. As expected the reliability indices are increased in the sensitivity cases for both 2018 and 2020 planning years and all loss of load events are in winter season. The minor changes in the LOLH and EUE indices for 2020 planning year is mainly due to the decrease in reserve margin for a 4 percent increase in peak load. The highest contribution to the loss of load event is still from the winter month of November for 2018 while it is from the winter month of March for 2020 planning year.

Sensitivity Case Study

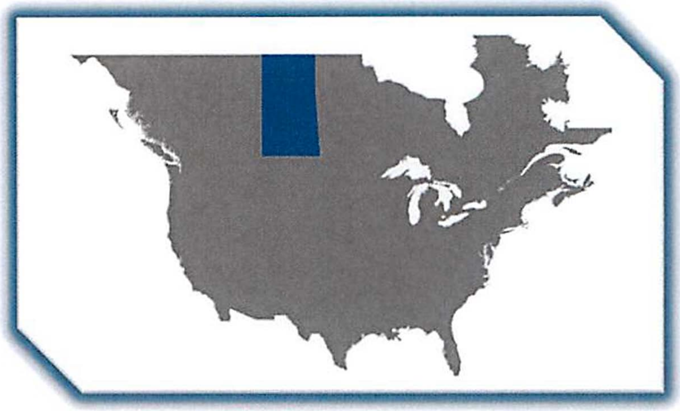
As expected the reliability indices are increased in the sensitivity cases for both 2018 and 2020 planning years and all loss of load events are in winter season. Although the planning reserve margin drops below the reference value of 12 percent for a 2 percent increase in peak load, the EUE and LOLE are still small for 2018 planning year. The minor changes in the LOLE and EUE indices for 2020 planning year is mainly due to the decrease in reserve margin for a 4 percent increase in peak load. The highest contribution to the loss of load event is still from the winter month of November for 2018 while it is from the winter month of March for 2020 planning year.

Monthly Reliability Measures

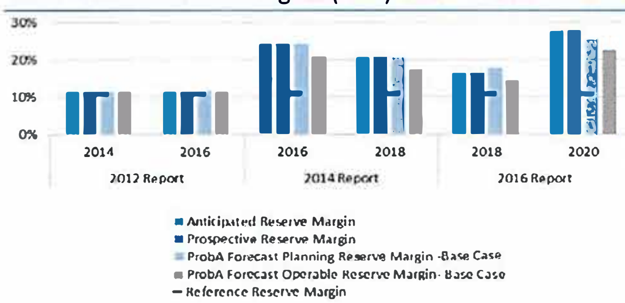
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.008	19	0.000	0	0.017	44	0.000	0
Feb	0.004	8	0.000	0	0.014	29	0.000	1
Mar	0.024	20	0.000	0	0.041	42	0.028	42
Apr	0.000	0	0.000	0	0.001	1	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun	0.000	0	0.000	0	0.000	0	0.000	0
Jul	0.000	0	0.000	0	0.000	0	0.000	0
Aug	0.000	0	0.000	0	0.000	0	0.000	0
Sep	0.000	0	0.000	0	0.000	0	0.000	0
Oct	0.000	0	0.000	0	0.000	0	0.000	0
Nov	0.027	44	0.000	0	0.157	218	0.002	4
Dec	0.016	27	0.000	0	0.031	55	0.000	0
Annual	**0.078**	**117**	**0.000**	**0**	**0.261**	**390**	**0.030**	**47**

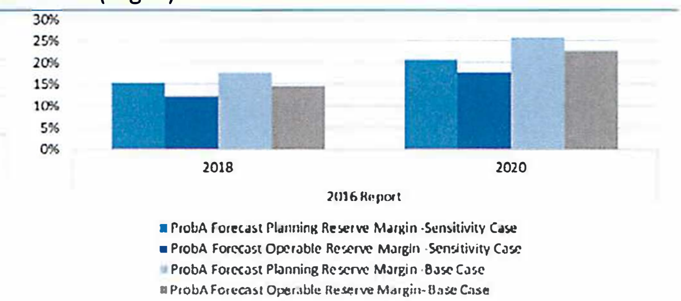
MRO –SaskPower

Saskatchewan is a province of Canada and comprises a geographic area of 651,900 square kilometers (251,700 square miles) with approximately 1.1 million people. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a Provincial Crown Corporation and under provincial legislation is responsible for the reliability oversight of the Saskatchewan bulk electric system and its interconnections.

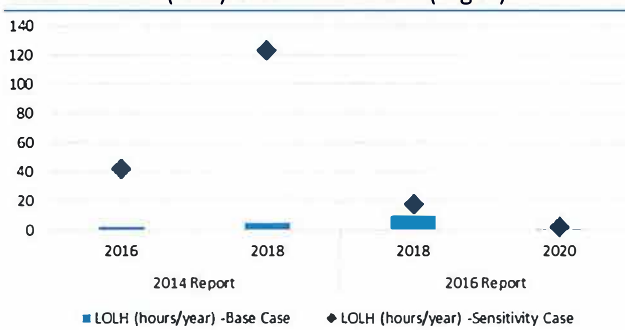


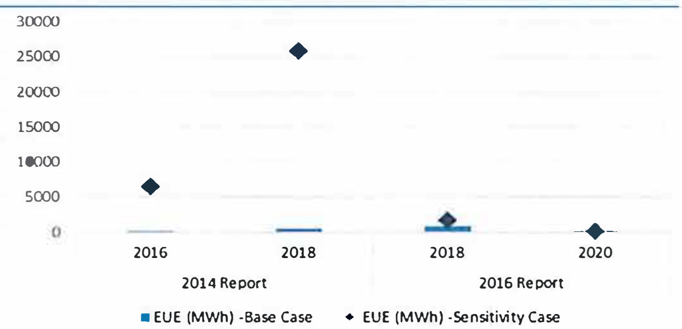
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)





Saskatchewan utilizes the Multi-Area Reliability Simulation (MARS) program for reliability planning with no transmission facility data used in this assessment, the model assumes that all firm capacity resources are deliverable within the assessment area. Weather has a significant impact on the amount of electricity consumed by nonindustrial customers. Due to this weather sensitivity, average daily weather conditions for the last thirty years are used in the weather normalization model to develop the energy forecast. Peak load is forecasted on a heating season basis and represents the highest level of demand placed on the supply system. One of the primary economic assumptions is that Saskatchewan's customer base will be maintained. The probability of the load falling within the bounds created by the high and low forecasts is expected to be 90 percent (confidence interval). Load Forecast Uncertainty is explicitly modeled utilizing a seven-step normal distribution with a standard deviation of 3 percent, 5 percent and 10 percent and takes into account weather and economic factors.

DR is modelled as an Emergency Operating Procedure by assigning a fixed capacity value and thus configured as a negative margin state for which MARS evaluates the required metrics. An Emergency Operating Procedure is initiated when the reserve conditions on a system approach critical levels.

Future planned generation that is included in the resource plan goes through a decision making process to get government approval as required. A thorough system economic risk evaluated analysis is completed on each project to determine the optimal solution to meet reliability requirements.

Saskatchewan plans for 10 percent of wind nameplate capacity to be available to meet summer peak and 20 percent of wind nameplate capacity to be available to meet winter peak demand.

Hydro generation is modeled as energy limited resource and utilized based on deterministic scheduling on a monthly basis. Annual hydro energy is calculated based on historical data that has been accumulated over the last 30 plus years.

Saskatchewan has contract in place for a firm import of 25 MW until March 2022 and also has a firm import of 100 MW starting July 2020 for a period of 20 years. There are no anticipated firm exports for the assessment period. Firm imports are modelled as load modifiers with hourly load modification for a typical week.

Operating procedures considered in the model are forgoing Operating Reserve, including Demand Response, and assumes that external emergency assistance is available to prevent a loss of load event.

Since the 2014 Probabilistic Assessment, the reported forecast reserve margin for year 2018 has slightly gone down from 20.6 percent to 17.8 percent mainly due to change in the expansion sequence. As expected, EUE and LOLH have increased when compared to analysis completed in 2014.

Most of the data is consistent with LTRA except the energy forecast and the expansion sequence, which has been updated to reflect the most recent projections.

Base Case Study

The major contribution to the 2018 LOLH and EUE is in the month of October (around 60 percent). There are maintenances scheduled to the largest coal and large natural gas units in that month. Most of the maintenance is scheduled during off-peak periods and can be rescheduled to mitigate short–term reliability issues. In the year of 2020, the LOLH and EUE are highest in January due to winter load.

Sensitivity Case Study

Similar monthly trend is observed in the sensitivity case. As compared to the base case, reserve margin has decreased from 17.8 percent to 15.4 percent and from 25.6 percent to 20.7 percent for year 2018 and 2020, respectively.

The effect of higher load growth is evident on the reliability metrics. EUE is almost doubled from the base case in both study years. EUE reported for sensitivity case is 1639.5 MWh/yr and 147 MWh/yr for the year 2018 and 2020, respectively.

Monthly Reliability Measures

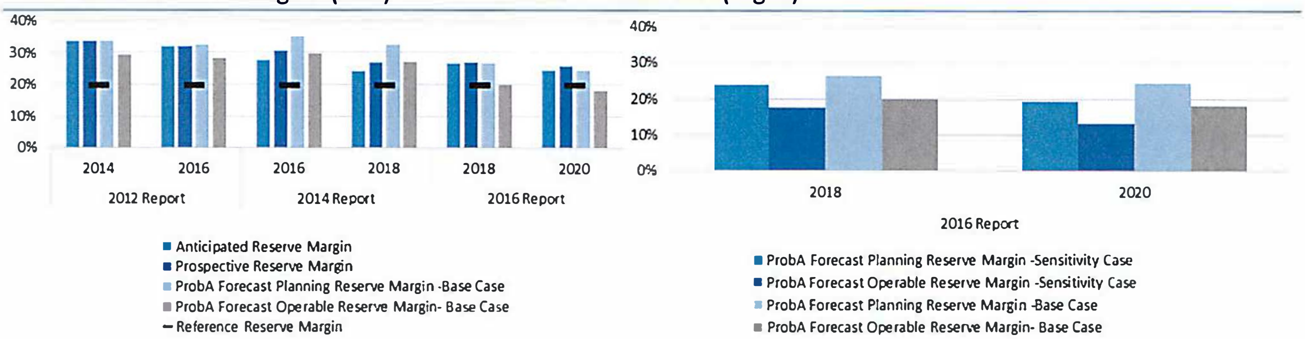
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.218	18	0.252	20	0.441	38	0.540	46
Feb	0.182	14	0.097	7	0.381	31	0.258	22
March	0.191	15	0.141	11	0.391	32	0.297	24
April	0.262	20	0.031	2	0.533	41	0.067	5
May	0.071	5	0.059	4	0.140	10	0.118	9
June	0.138	10	0.031	2	0.278	21	0.055	4
July	0.232	18	0.001	0	0.454	38	0.004	0
August	0.241	19	0.012	1	0.475	38	0.055	4
Sept	0.595	46	0.031	2	1.095	90	0.054	4
Oct	5.391	523	0.040	3	8.898	904	0.027	2
Nov	1.443	133	0.081	7	2.660	251	0.166	15
Dec	0.817	72	0.060	5	1.560	145	0.129	11
Annual	**9.781**	**894**	**0.836**	**66**	**17.306**	**1,640**	**1.770**	**147**

NPCC

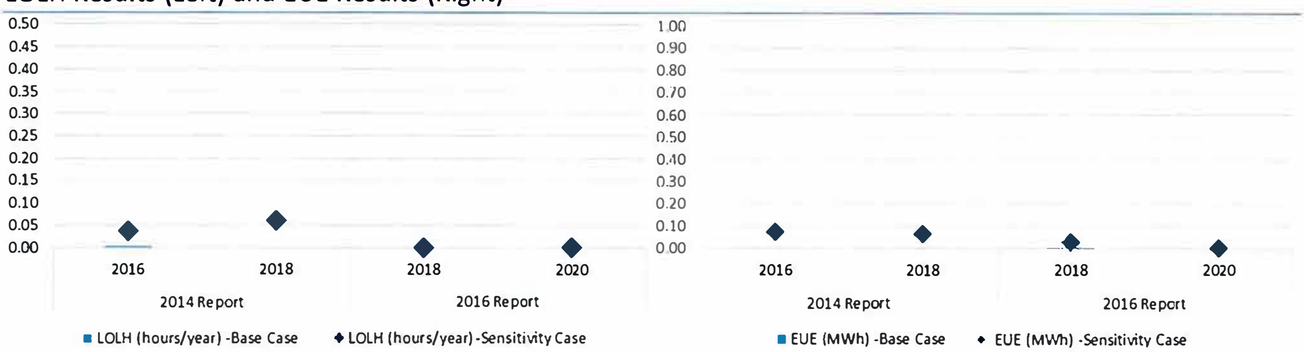
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC subregion that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles, with a total population of 1.9 million people.

Base Case Reserve Margins (Left) and Probabilistic Measures (Right)



LOLH Results (Left) and EUE Results (Right)



The Maritimes Area is a winter peaking area. The previous study, *"NERC RAS Probabilistic Assessment – NPCC Region"* [9] estimated an annual LOLH = 0.000 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 Forecast 50/50 Peak Demand Forecast is 262 MW greater in this assessment than reported in the previous assessment, reflecting increases in electric heating loads which were not quite offset by declines in industrial loads and demand shifting programs. Forecast Capacity Resources increased by 81 MW in the 2016 Probabilistic Assessment as compared to the previous assessment. No material difference in estimated LOLH and EUE is observed between the two assessments. Increased capacity resources, coupled with reliance on operating procedures and tie benefits contribute to this result.

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[9] See: https://www.npcc.org/Library/Resource%20Adequacy/2014%20NERC%20RAS%20Probabilistic%20Assessment%20NPCC%20Region%20(March%2031,%202015).pdf

Maritimes DR interruptible loads are forecast on a weekly basis and are available for use when corrective action is required within the Area.

The Maritimes Area employs a reserve criterion of 20 percent of firm load. To relate the Maritimes Area reserve criterion of 20 percent to the NPCC resource adequacy criterion, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20 percent. The results showed that a Maritimes Area reserve of 20 percent corresponds to an LOLE of approximately 0.086 days per year.

The Maritimes Area has a diversified mix of capacity resources fueled by nuclear, oil, coal, natural gas, dual fuel oil/natural gas, hydro, wind (de-rated), biomass, and tie benefits with no one type feeding more than about 26 percent of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. The Maritimes Area does not anticipate fuel disruptions that pose significant challenges to resource adequacy in the area during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues such as potential restrictions to greenhouse gas emissions.

Forced Outage Rates for existing generators are based on actual outage data as well as on data of similar sized generators as compiled by the Canadian Electricity Association (CEA). FORs for new generators are based upon the utilities' experience with similar generators in conjunction with averages compiled by the Canadian Electricity Association (CEA). Immature FORs were not used in this assessment.

The Maritimes Area has begun tracking ramp rate variability trend but does not yet have enough historical years of data for the Area as a whole to identify any trends. Given the essentially flat load growth and small degree of anticipated VER installations, little change in either ramp rates or the Area's resource mix is expected to occur for the duration of the LTRA assessment period. The maximum Net Demand Ramping Variability 1 hour up, 1 hour down, 3 hours up, and 3 hours down values for two historical years of 2014 and 2015 and a future year of 2020 were calculated along with the percentage contributions of Variable Energy Resources versus the loads. The majority of the maximums occurred during the late fall shoulder and winter peak seasons.

The Maritimes provides an hourly historical wind output for each sub-area. This profile is then scaled according to the wind online at the time of the regional peak. The LTRA reports de-rated nameplate values.

Transmission additions and retirements assumed in the modeling was consistent with the data provided for the *NERC 2016 Long-Term Reliability Assessment*.

Base Case Study

No significant LOLH is observed. EUE is 0.005 in 2018 and negligible in 2020. Anticipated Reserve Margins are well above 20 percent in both years. The greatest contribution to the LOLH and EUE occur during the peak (winter) monthly period.

Sensitivity Case Study

LOLH is also not significant in this case, the EUE values are negligible: 0.03 and 0.004 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above 20 percent in 2018 and near 20 percent in 2020.

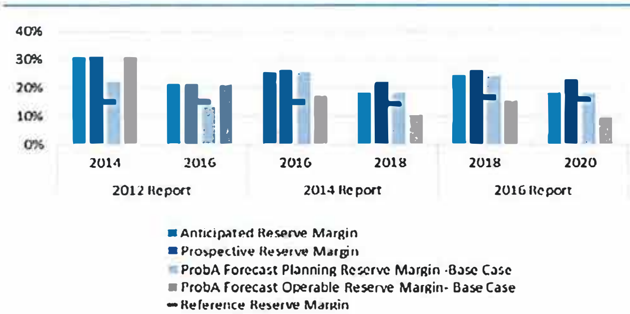
Monthly Reliability Measures

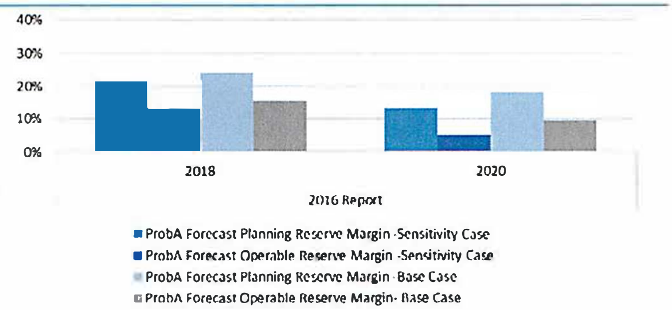
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
March	0.000	0	0.000	0	0.000	0	0.000	0
April	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
June	0.000	0	0.000	0	0.000	0	0.000	0
July	0.000	0	0.000	0	0.000	0	0.000	0
Aug	0.000	0	0.000	0	0.000	0	0.000	0
Sept	0.000	0	0.000	0	0.000	0	0.000	0
Oct	0.000	0	0.000	0	0.000	0	0.000	0
Nov	0.000	0	0.000	0	0.000	0	0.000	0
Dec	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**

NPCC-New England

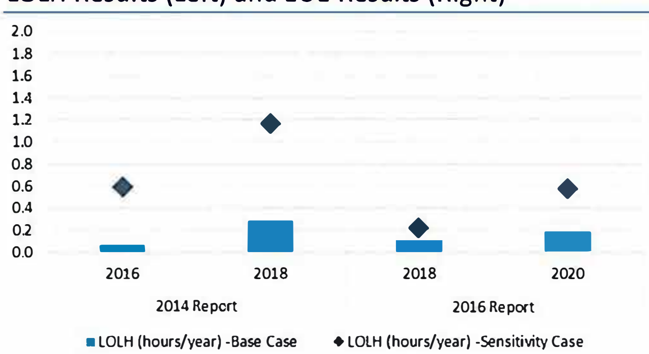
ISO New England (ISO-NE) Inc. is a regional transmission organization that serves Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the area's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

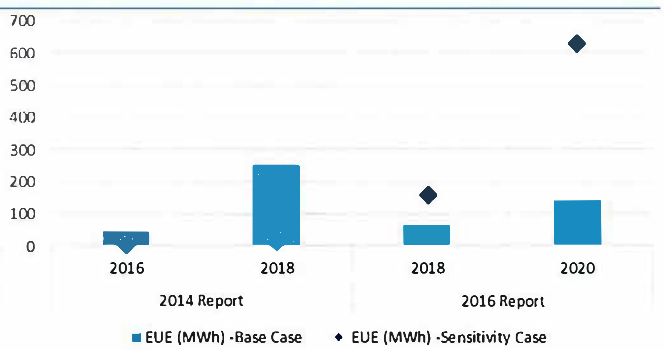
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)





The GE MARS simulation data model developed by the NPCC CP-8 Working Group was used; modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.

The previous study, *"NERC RAS Long-Term Reliability Assessment – NPCC Region"* [10] estimated an annual LOLH = 0.288 hours/year and a corresponding EUE equal to 253.8 MWh for the year 2018. The Forecast 50/50 Peak Demand for 2018 was lower than reported in the previous study; with higher estimated Forecast Planning and Forecast Operable Reserve Margins. As a result, both the LOLH and the EUE have improved for 2018.

[10] See: https://www.npcc.org/Library/Resource%20Adequacy/2014%20NERC%20RAS%20Probabilistic%20Assessment%20NPCC%20Region%20(March%2031,%202015).pdf

Demand Response: New England Passive and active demand resources participate in the New England Forward Capacity Market (FCM), and are represented as supply-side resources in this study. The Qualified Capacity of passive demand resources under the FCM are used for the years 2017 to 2019, and a forecast amount is used for 2020 and 2019. For the active demand resources, the study assumes the actual amount procured under the FCM.

This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon each unit's historical five-year average of scheduled maintenance. Individual generating unit forced outage assumptions were based on the unit's historical data and North American Reliability Corporation (NERC) average data for the same class of unit. Approximately 373 MW of Behind the Meter photovoltaic resources are assumed to reduce the internal demand.

New England utilizes wind units of a fixed capacity (that varies seasonally) representing the Seasonal Claimed Capability to represent their wind resources. In the LTRA, both nameplate ratings and Seasonal Claimed Capabilities for wind units are reported. The Seasonal Claimed Capabilities in the Probabilistic assessment are consistent with the LTRA.

New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance.

Base Case Study

In 2018, LOLH is 0.109 h/year and EUE is 65.2 MWh, while in 2020 those values are 0.189 h/year and 140.8 MWh, respectively. The increases are consistent with a decline in reserve margins. The metrics are primarily driven by the results in July and August.

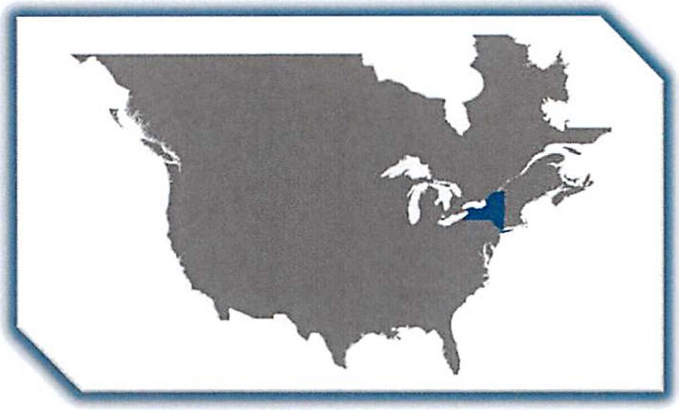
Sensitivity Case Study

LOLH and EUE increase exponentially with the decline in reserve margins. LOLH is 0.218 and 0.573 h/year for the 2018 and 2020, respectively. EUE is 157.7 and 528.6 MWh for those two years. As it was the case in the Base case, July and August have the biggest share of the annual metrics.

Monthly Reliability Measures

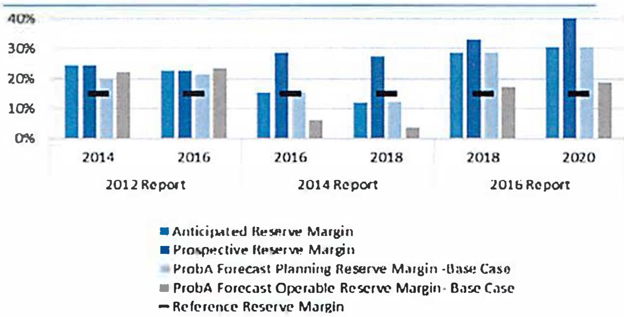
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0.005	2	0.001	1	0.035	25
July	0.036	20	0.067	44	0.078	51	0.226	227
Aug	0.073	45	0.117	94	0.139	106	0.31	376
Sept	0	0	0	0	0	0	0.002	1
Oct	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0
Annual	0.109	65	0.189	141	0.218	158	0.573	629

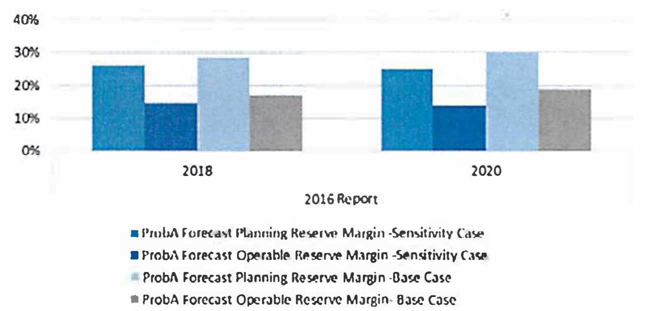
NPCC-New York



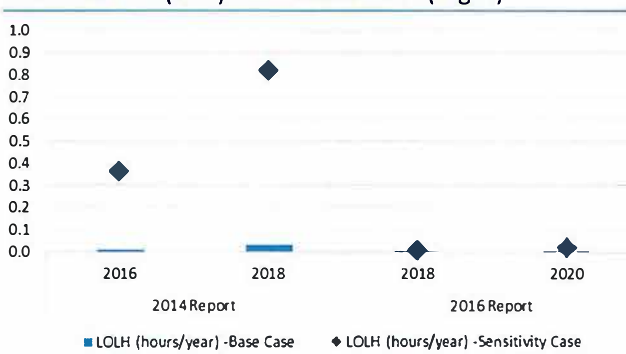
The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA). NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. NYISO manages the New York State transmission grid, encompassing approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

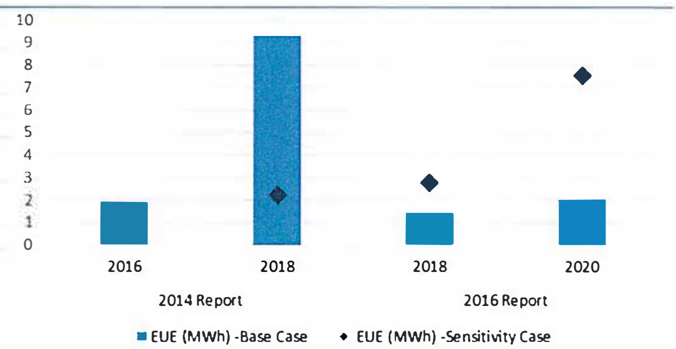
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)





The New York Area is a summer peaking area. The GE MARS simulation data model developed by the NPCC CP-8 Work Group was used, modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.

The previous study, "NERC RAS Long-Term Reliability Assessment – NPCC Region"[11] estimated an annual LOLH = 0.032 hours/year and a corresponding EUE equal to 9.3 MWh for the year 2018. The Forecast 50/50 Peak Demand

11 https://www.npcc.org/Library/Resource%20Adequacy/2014%20NERC%20RAS%20Probabilistic%20Assessment%20NPCC%20Region%20(March%2031,%202015).pdf

for 2018 was lower than reported in the previous study; with higher estimated Forecast Planning and Forecast Operable Reserve Margins. As a result, both the LOLH and the EUE have improved for 2018.

The New York Installed Reserve Margin (IRM) of 17.5 percent applies to the period May 2016 to April 2017; [12] New York's IRM is set annually. New York does not have a future Reference Reserve Margin beyond the current capability period; the NERC Reference Reserve Margin is shown.

Solar generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate MW value based on 2013 production data. Characteristics of this data indicate an overall 47 percent capacity factor during the summer peak hours. A total of 31.5 MW of solar capacity was included in this study.

Wind capacity is assumed to operate at a 14 percent capacity factor during the summer peak period. This assumed capacity factor is based on an analysis of actual hourly wind generation data collected for wind facilities in New York State during the June through August 2013 period between the hours of 2:00 p.m. and 5:00 p.m. This test period was chosen because it covers the time during which virtually all of the annual New York Area LOLE occurrences are distributed. For the probabilistic assessment, the wind generators are modeled as hourly load modifiers, where the output of each unit can vary between 0 MW and the Capacity Resource Interconnection Service value based on 2013 production data.

All generator values for New York reported in the 2016 LTRA based the current Load and Capacity Data Report issued by the New York Independent System Operator.

Base Case Study

LOLH for 2018 and 2020 are 0.004 (hours/year) with EUE values of 1.448 and 2.059 (MWh). The EUE are negligible. Results are similar driven by a comparable planning reserve margin in both years. The summer months (June-August) have the greatest contribution to these metrics.

Sensitivity Case Study

LOLH values are 0.007 and 0.021 for 2018 and 2020, respectively. EUE results are 2.8 and 7.6 MWh for those same two years. The monthly contribution is similar to that observed in the Base Case.

Monthly Reliability Measures

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0.001	1	0	0	0.002	2
July	0.002	1	0.002	0	0.004	1	0.014	4
Aug	0.002	1	0.001	1	0.003	1	0.005	2
Sept	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0

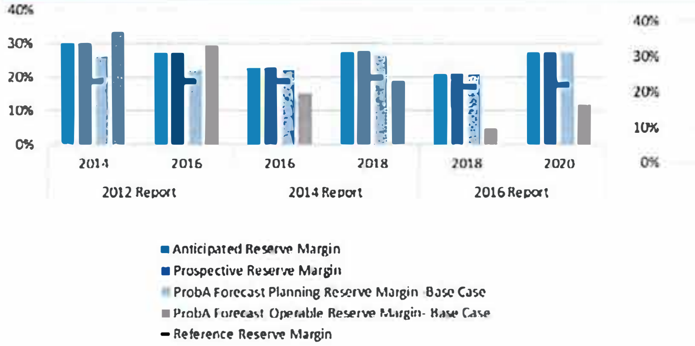
[12] See: http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html

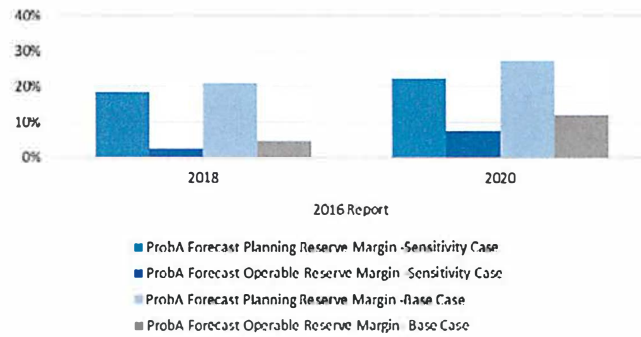
Dec	0	0	0	0	0	0	0	0
Annual	**0.004**	**1**	**0.004**	**2**	**0.007**	**3**	**0.021**	**8**

NPCC-Ontario

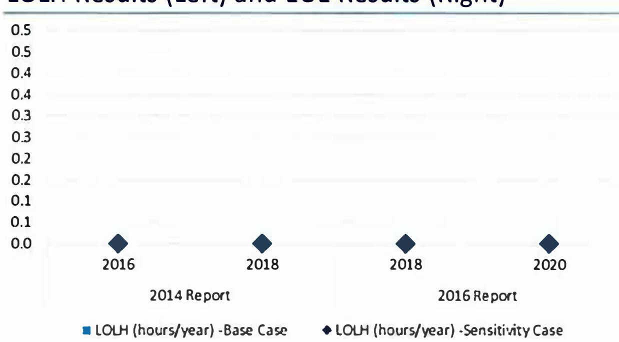
The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)



The Ontario Area is a summer peaking area. The GE MARS simulation data model developed by the NPCC CP-8 Working Group was used, modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.

The previous study, "NERC RAS Long-Term Reliability Assessment – NPCC Region" 13 estimated an annual LOLH = 0.0 hours/year and a corresponding EUE equal to 0.0 (ppm) for the year 2018. The 2018 Forecast 50/50 Peak Demand Forecast is 218 MW greater in this assessment than reported in the previous assessment, reflecting the interplay of economic expansion, population growth and increased penetration of electrically powered devices act to increase the need for electricity, and conservation programs, increasing embedded generation output and

[13] See: NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015

prices that act to reduce the amount of grid-supplied electricity needed. There is no change in the estimated LOLH and EUE between the two assessments, mainly due to the contributions various demand response programs, operating procedures and tie benefits.

The Ontario IESO, in its own assessments, treats Demand Response as a resource instead of a load modifier. As a consequence, reserve margin calculations are lower in IESO reports when compared to NERC assessments.

The loads for each area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies. The majority of the NPCC Areas provide only the annual peak for the 2016 Summer Assessment, except for Ontario.
Ontario's Demand Response (D) is comprised of the following programs: DR auction, DR pilot, peaksaver, dispatchable loads, Capacity Based Demand Response (CBDR), time-of-use (TOU) tariffs, and the Industrial Conservation Initiative (ICI). Dispatchable loads and CBDR resources can be dispatched in the same way that generators are, whereas TOU, ICI, conservation impacts, and embedded generation output are factored into the demand forecast as load modifiers.

The capacity values and planned outage schedules for thermal units are based on monthly maximum continuous ratings and planned outage information contained in market participant submissions. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data.

Hydroelectric resources are modelled in MARS as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity and monthly energy values are determined on an aggregated basis for each zone based on historical data since market opening (2002).
Solar generation is aggregated on a zonal basis and is modelled as load modifiers. The contribution of solar resources is modelled as fixed hourly profiles that vary by month and season.

Wind generation is aggregated on a zonal basis and modelled as an energy limited resource with a cumulative probability density function (CPDF) which represents the likelihood of zonal wind contribution being at or below various capacity levels during peak demand hours. The CPDFs vary by month and season.

Base Case Study

There was no significant LOLH or EUE observed for the base case study for either 2018 or 2020. Anticipated Reserve Margins are above 17.31 percent and 17.76 percent in 2018 and 2020, respectively.

Sensitivity Case Study

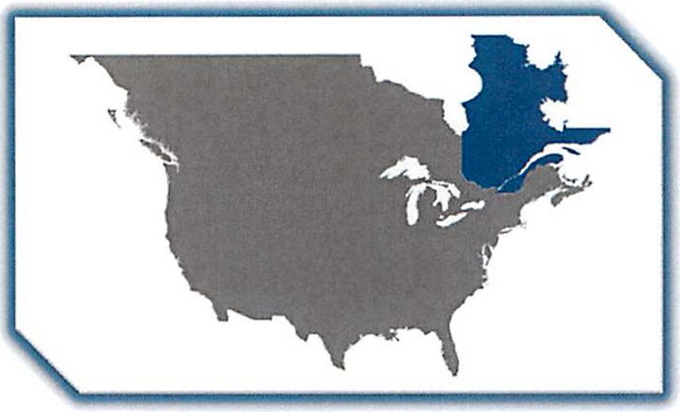
LOLH values are not significant in this case; the EUE are negligible: .004 and .074 MWh for 2018 and 2020, respectively. Anticipated Reserve Margins remain above the Base Case Reference Reserve Margin in both years. The greatest contribution to EUE occurs during the peak (summer) monthly period.

Monthly Reliability Measures

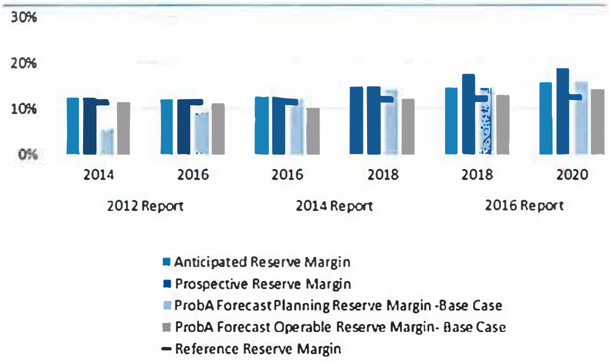
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0
Sept	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0
Annual	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

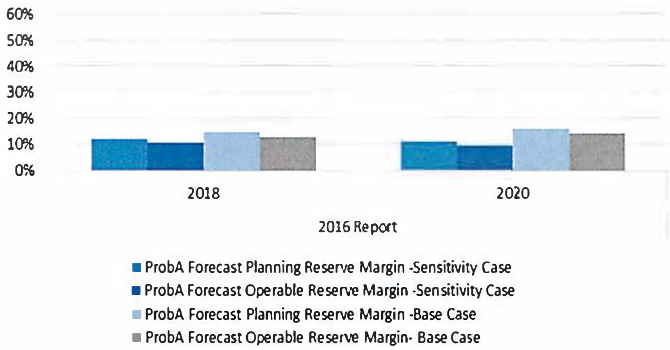
NPCC- Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

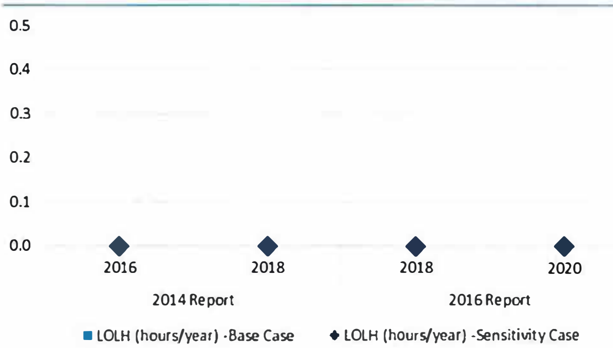


Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)



Québec is a winter peaking area. The GE MARS simulation data model developed by the NPCC CP-8 Working Group was used, modeling demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures, as prescribed by the NPCC resource adequacy criterion.

The previous study, "NERC RAS Long-Term Reliability Assessment – NPCC Region" [14] estimated an annual LOLH = 0.0 hours/year and a corresponding EUE equal to 0.0 for the year 2018. The Forecast 50/50 Peak Demand for 2018 was lower than reported in the previous study; with slightly higher estimated Forecast Planning and Forecast Operable Reserve Margins. As a result, there is no change in the estimated LOLH and EUE in this year's study.

[14] See: NERC RAS Probabilistic Assessment: NPCC Region; March 31, 2015

Québec's Reference Reserve Margin is determined based on the NPCC resource adequacy criterion; results indicate a Reference Reserve Margin of 12.7 percent. [15]

The Québec Area demand forecast average annual growth is 0.7 percent during the 10-year period, similar to last year's forecast. Total Internal Demand is calculated for the Québec area as a single entity and the Area's peak demand forecast is coincident.

Demand Response (DR) programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs (for large industrial customers), totaling 1,748 MW for the 2017–2018 winter period. DR programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand.

The Québec Area will support firm capacity sales totalling 750 MW during the 2017–2018 winter peak period, declining to 145 MW for the 2020-2021 winter period and after.

Base Case Study

No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are above the Reference Reserve Margins for 2018 and 2020, respectively.

Sensitivity Case Study

No LOLH or EUE was estimated for 2018 or 2020. The Anticipated Reserve Margins are near the Reference Reserve Margins.

Monthly Reliability Measures

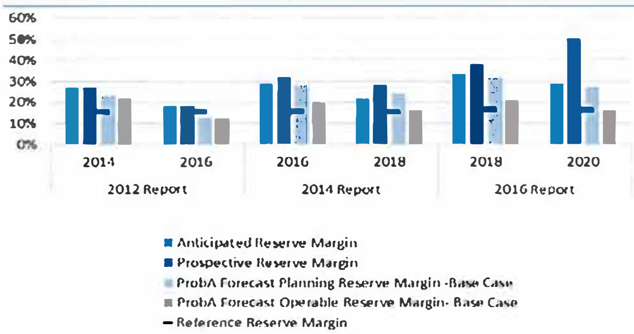
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0
Sept	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0
Annual	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

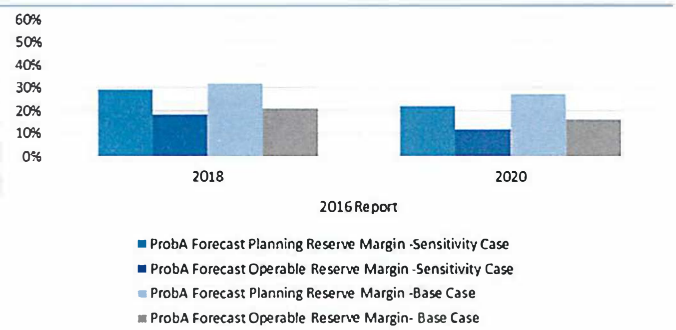
[15] See: NPCC 2015 Québec Balancing Authority Area Interim Review of Resource Adequacy; December 1 2015

PJM

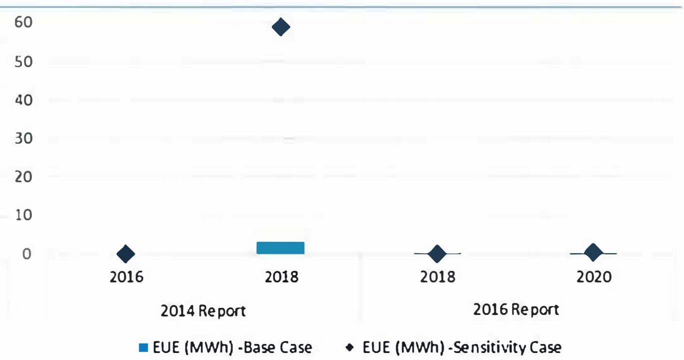
PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM companies serve 61 million people and covers 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)



The study was conducted by the NPCC CP-8 WG, with full participation of PJM Staff. PJM staff has participated in the CP-8 WG efforts since 2005. PJM supplied the modeling data for most of the CP-8 WG external region which includes the full PJM RTO footprint. NPCC collaborates with PJM on interregional assessments to allow sharing of model data, analysis methods, and assessment techniques.

The 2018 LOLH and EUE in the *2016 ProbA* are smaller than the corresponding values reported in the *2014 ProbA*:

- 2018 LOLH in 2016 ProbA = 0.000 hrs./year vs 2018 LOLH in 2014 ProbA = 0.009 hrs./year
- 2018 EUE in 2016 ProbA = 0.003 MWh/year vs 2018 EUE in 2014 ProbA = 9.300 MWh/year

This difference can be explained by the larger planning and operable reserves for 2018 in the 2016 ProbA compared to those in the 2014 ProbA. The increase in 2018 reserves is due to a reduction in Net Internal Demand and an increase in Forecast Capacity Resources. In particular, the increase in Forecast Capacity Resources is due to the fact that by the time the *2014 ProbA* was run none of the 2018 capacity market auctions had been cleared;

in contrast, the Forecast Capacity Resources for 2018 considered in the 2016 ProbA include capacity secured via capacity market auctions.

For Summer 2018 and Summer 2020, the Probabilistic Reserve Margin in slightly lower than the Deterministic value due to 2,500 MW of on-peak capacity derates as a result of above average summer ambient conditions.

Intermittent generators were modeled as a regular resource at their respective capacity values (average capacity value for wind is 13 percent while for solar is 38 percent).
Load Forecast Uncertainty was modeled on a monthly basis using a normal distribution discretized in 7 steps.

Demand Response (DR) resources were modeled as an emergency operating procedure triggered whenever the reserves in each of the 5 regions fall below a certain threshold (the sum of the threshold in the 5 PJM regions is 3,400 MW). DR resources are modeled as the first EOP (Curtail Load/Utility Surplus). Of the total DR available in 2018, 98 percent corresponds to DR available in the period June-September while 2 percent corresponds to DR available all year long. This difference in availability is reflected in the GE-MARS runs. In 2020, all DR resources are available all year long. DR resources (8,977 MW for 2018 and 3,416 MW for 2020) are subtracted from the Total Internal Demand yielding the Net Internal Demand value 146,936 MW in 2018 and 153,471 MW in 2020.

Imports and exports modeled for Summer 2020 are expected quantities (while those modeled for Winter 2018, Summer 2018, and Winter 2020 are firm quantities since capacity market auctions covering those periods have been run as of the time of running the 2016 Probabilistic Assessment).

There are minor discrepancies between the Total Internal Demand reported in the *2016 LTRA* for 2018 and 2020 and the corresponding values in the 2016 Probabilistic Assessment. These discrepancies arise from the fact that in the 2016 Probabilistic Assessment PJM is modeled using 5 different regions with their respective Summer 2002/Winter 2004 hourly load shapes. In order to match the PJM peak load reported in the LTRA, the noncoincident peaks of the 5 PJM regions were adjusted by suitable factors.

Behind the Meter Generation is not explicitly modeled in this study. The impact of Behind the Meter Generation is reflected in a lower load forecast[16].

In PJM's Installed Reserved Margin study, the portion of total import capability that is reserved for reliability purposes is only 3,500 MW. This restriction is not modeled in the Probabilistic Assessment study (in other words, in the Probabilistic Assessment, all of PJM's import capability can be used to reduce LOLH or EUE).

No transmission outages were considered in PJM probabilistic analysis.

Base Case Study

The Base Case results in LOLH equal to zero for both 2018 and 2020 due to large Forecast Planning reserve margins (significantly above the reference value of 16.5 percent). EUE is virtually zero (though technically nonzero) for both 2018 and 2020. The only month that contributes a rather minuscule but discernible amount of EUE in both years is April due to planned maintenance and large load uncertainty for some of the areas within PJM.

Sensitivity Case Study

The Sensitivity Case results in LOLH equal to zero for 2018. For year 2020, LOLH exhibits a very mild uptick (i.e. 0.001 hours/year) during April due to a large amount of planned maintenance and large load uncertainty for some

[16] PJM has developed a methodology to estimate the amount of solar BTM which can be found in the 2016 PJM Load Forecast Report

of the areas within PJM. EUE is slightly higher than under the Base Case for both 2018 and 2020 but still very close to zero. Months that contribute to the EUE in the Sensitivity Case are April (due to the reasons mentioned above explaining the LOLH uptick in 2020) and July (where the PJM annual peak occurs). As expected, LOLH and EUE increase under the Sensitivity Case. This increase is more pronounced in 2020 due to lower installed reserves in PJM (compared to the reserves in 2018).

Monthly Reliability Measures

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	1
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0
Sept	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0
Annual	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**

SERC

SERC is a summer-peaking assessment area that covers approximately 308,900 square miles and serves a population estimated at 39.4 million. SERC is divided into three assessment areas: SERC-E, SERC-N, and SERC-SE. The SERC Region includes 11 BAs: Alcoa Power Generating, Inc. – Yadkin Division (Yadkin), Associated Electric Cooperative, Inc. (AECI), Duke Energy Carolinas and Duke Energy Progress (Duke), Electric Energy, Inc. (EEI), LG&E and KU Services Company (as agent for Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU)), PowerSouth Energy Cooperative (PowerSouth), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (Santee Cooper, SCPSA), Southern Company Services, Inc. (Southern), and Tennessee Valley Authority (TVA).

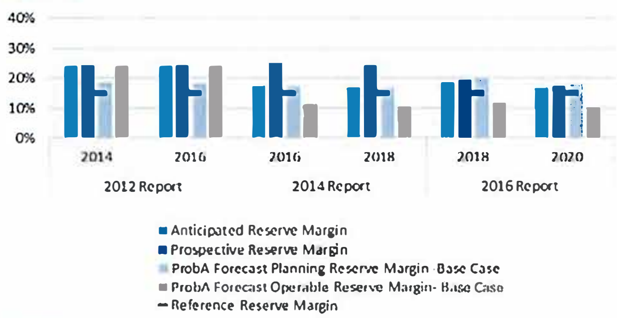
SERC-East Assessment Area Footprint

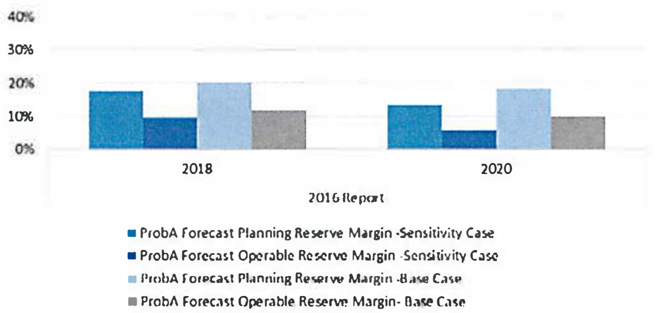
SERC-North Assessment Area Footprint

SERC-Southeast Assessment Area Footprint

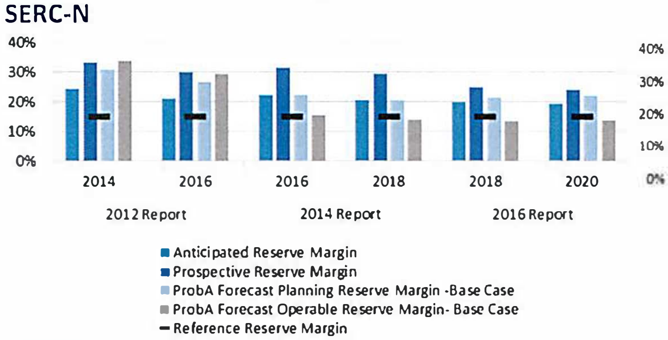
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)

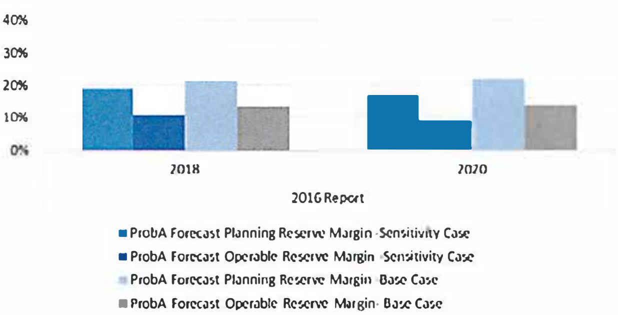
SERC-E



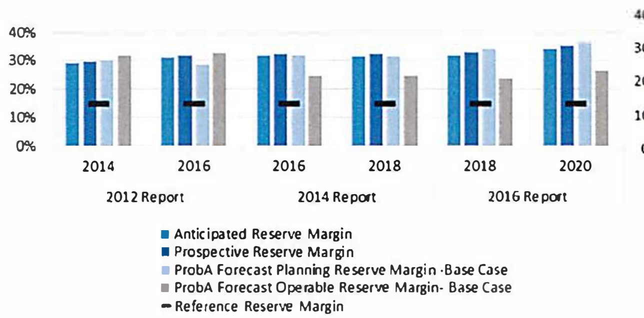


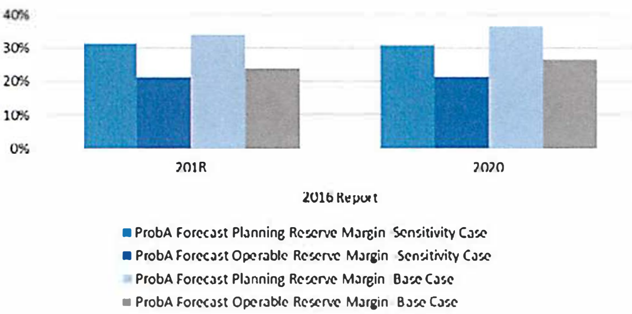
SERC-N





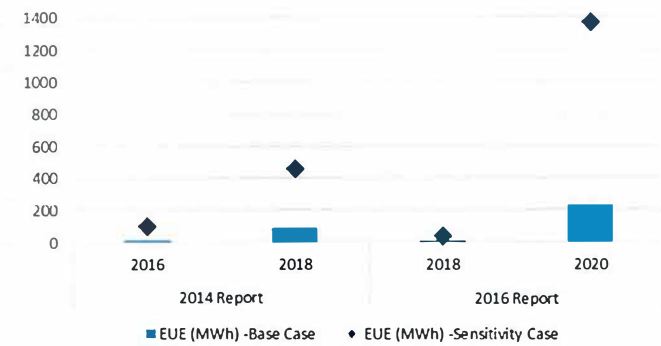
SERC-SE



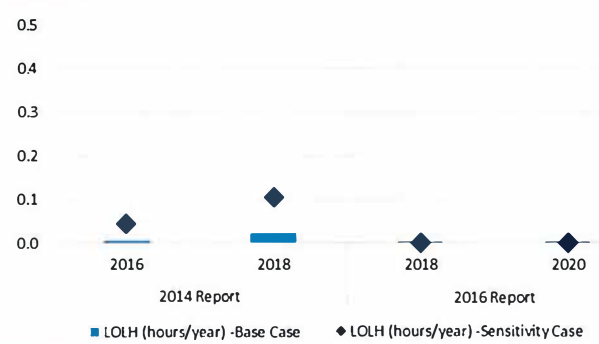


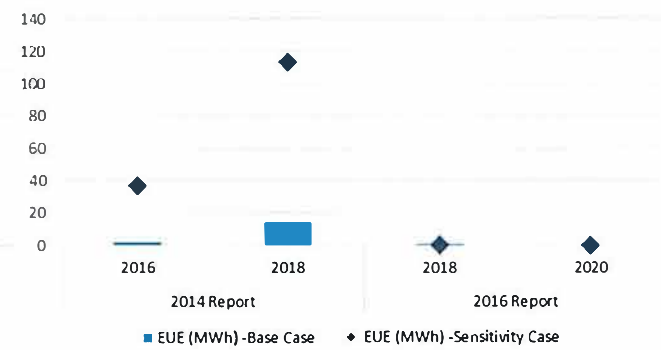
LOLH Results (Left) and EUE Results (Right)

SERC-E

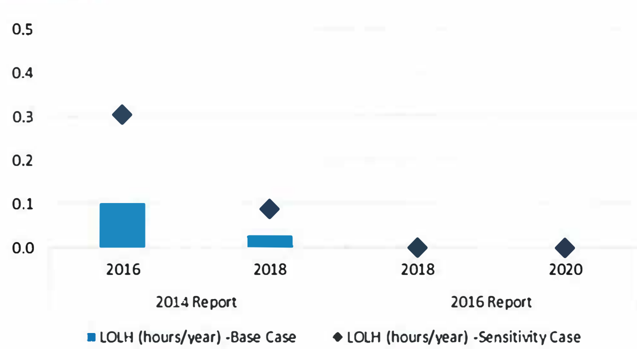


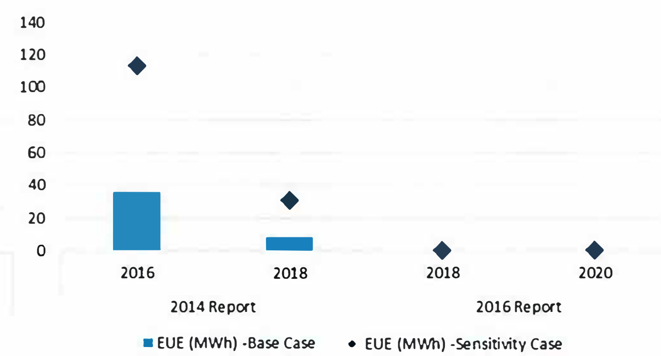
SERC-N





SERC-SE





SERC utilizes an 8760 hourly load, generation, and transmission simulation model consisting of 3 internal NERC assessment areas (SERC-E, SERC-N, and SERC-SE) and 7 connected external areas (10 total external areas). First Contingency Incremental Transfer Capability (FCITC) analysis sets limits for nonfirm support amongst internal and external areas, while positive and negative demand side resources represent net firm interchange schedules. Forecast assumptions for normal (50/50) coincident demand, net energy for load, and anticipated resources from the Long-term Reliability Assessment are input for the model, and further analysis determines uncertainty parameters such as load forecast uncertainty (LFU), generator forced outage rates, etc.

From 2014 Probabilistic Resource Assessment (PRA) to 2016 PRA, the SERC-E LOLH decreased by approximately 97 percent (0.085 to 0.002) for the same study year 2018. This is primarily driven by lower projected demand mentioned above, but also due to 2016 modeling corrections. The SERC PRA model now includes expected firm capacity transfers and improvements to winter historical load profiles. [17] After accounting for lower demand and modeling corrections, SERC-E base case 2018 results remain static from 2014.

[17] Approximations: 0.085 (2014 PRA- 2018 LOLH) minus 0.080 (decrease load forecasts from 2014 to 2016) minus 0.003 (modeling corrections) equals 0.002

The generation system reliability indices for the three SERC LTRA assessment areas being modeled were calculated for the current reserve level projections (base case) from the *2016 LTRA* filings, as well as for one increased demand and energy sensitivity case, for the purposes of the NERC probabilistic assessment effort. MARS was used to calculate the system reliability in terms of hourly LOLE (LOLH) and expected unserved energy (EUE).

This study assumes that there are no transmission limits within an area (with the exception of SERC-PJM, consequently, any generating units assigned to an area can serve any load associated with that area. This study models transfer limits between the areas, and so the areas are typically defined by the limiting interfaces that may exist throughout the transmission system.

The SERC Long-Term Study Group (LTSG) establish first contingency incremental transfer capability (FCITC) limits for the winter and summer seasons of each study year in each direction between pairs of interconnected areas (assessment areas and/or subareas). The study model holds these limits constant 24/7 for each study iteration. Transfer limits (FCITC) were calculated for each assessment area by simulating transfers with load-to-generation shifts into each area simultaneously from each adjacent area using linear transfer techniques. Incremental interface import capability was then allocated to each area participating in the transfer, including the areas external to SERC, based upon each area's participation factor.

For internal load modeling, SERC used annual load shapes for the several years between 2007 and 2013 with each year has its own weighted average value. For modeling the eternal areas, SERC used various typical years.

LFU was modeled independently for each of the three SERC areas.

The forecasted coincident annual peak demand for SERC-SE is 47,513 MW and 48,282 MW in 2018 and 2020 respectively. The average system diversity of the SERC LTRA area during the summer is 0.95 percent while during the winter it is 1.72 percent. SERC is typically a summer peaking LTRA area; however, areas in certain years did peak during winter months. On average though, the winter season peak is approximately 93 percent of the annual peak demand (SERC-E app. 96 percent; SERC-N app. 97 percent, and SERC-SE app. 90 percent).

For this study, statistical analysis of the SERC LTRA assessment area coincident historical hourly load data from the aggregation of entities' FERC 714 filings (1993-2014) establishes the load forecast uncertainty (LFU) for SERC-N, SERC-E, and SERC-SE. This study not only accounts for historical weather patterns, but also applies a probability weighting to each load shape based upon each shapes inherent risk to loss of load. In this study, the effects of such DSM are embedded in the 50/50 load forecasts.

Base Case Study

SERC-E LOLH and EUE increase from 0.002 hours/year and 1.4 MWh respectively in 2018 to 0.046 hours/year and 49.4 MWh respectively in 2020 due to an approximate 3 percent increase in peak demand and minimal increase in anticipated resources. However, the rise of the metrics in 2020 is not concerning considering the MW size of SERC-E. Measures not modeled in the 2016 PRA such as, but not limited to, voluntary and non-controllable demand response, operating procedures to cut nonfirm schedules or maintenance, public appeals, and other mechanisms should mitigate 49.4 MWh of annual expected unserved energy within SERC-E.

LOLH and EUE accrue relatively evenly across all months of the year in 2018; however, with increase in demand by 2020, the majority of LOLH and EUE accrues during the peak seasons of summer and winter. Actually, between 60 and 70 percent occurs during the winter months. This is contributable to a high per unit of annual 50/50 demand and higher winter load forecast uncertainty due to events like the 2014 Polar Vortex where annual peaks occurred for many entities within SERC-E during winter months.

SERC-N entities expect a 0.81 percent compound annual growth rate (CAGR). However, the model results for 2020 base summer yielded near 0 percent growth from 2018. However, since the expected growth is below 1 percent, the resulting impact on the indices is negligible.
SERC-SE Zero LOLH and EUE

Sensitivity Case Study

SERC-E entities expect a 1.44 percent compound annual growth rate (CAGR). The NERC sensitivity case doubles the SERC-E CAGR to 2.90 percent. In this load growth scenario, SERC-E LOLH and EUE increase to 0.009 hours/year and 7.6 MWh respectively in 2018 and to 0.373 hours/year and 467.7 MWh respectively in 2020.

SERC conducts its own independent resource adequacy assessment with supplementary sensitivity analysis on load growth and load forecast uncertainty. These cases will further demonstrate the influence a decline in expected energy efficiency gains and changes in other demand factors may pose to SERC-E resource adequacy and will be published quarter one of 2017.

SERC-N the NERC sensitivity case doubles the SERC-N CAGR to 1.74 percent. In this load growth scenario, SERC-N LOLH and EUE increase, but of minimal consequence to resource adequacy, to 0.003 hours/year and 1.8 MWh respectively in 2018 and to 0.001 hours/year and 0.8 MWh respectively in 2020. The resulting metrics for 2020 are lower than 2018 due to gas-fired generation additions to SERC-N mid-year 2018. Subsequently, the winter months in 2020 reflect lower accrual of LOLH and EUE than in 2018.

SERC-SE the NERC sensitivity case doubles the SERC-SE CAGR to 2.52 percent. In this load growth scenario, SERC-SE LOLH and EUE still remain zero.

Monthly Reliability Measures

SERC-E

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.008	10	0.078	117	0.018	24	0.268	486
Feb	0.001	1	0.022	32	0.002	2	0.074	130
Mar.	0.000	0	0.001	0	0.000	0	0.005	5
Apr.	0.000	0	0.000	0	0.000	0	0.001	1
May	0.000	0	0.004	5	0.000	0	0.027	39
Jun.	0.000	0	0.003	3	0.001	0	0.057	58
July	0.000	0	0.012	12	0.006	5	0.177	219
Aug.	0.001	1	0.015	14	0.006	6	0.191	233
Sept.	0.000	0	0.000	0	0.000	0	0.004	4
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.001	1
Dec.	0.001	1	0.035	47	0.003	3	0.119	194
Annual	**0.012**	**13**	**0.171**	**231**	**0.038**	**41**	**0.925**	**1,370**

SERC-N

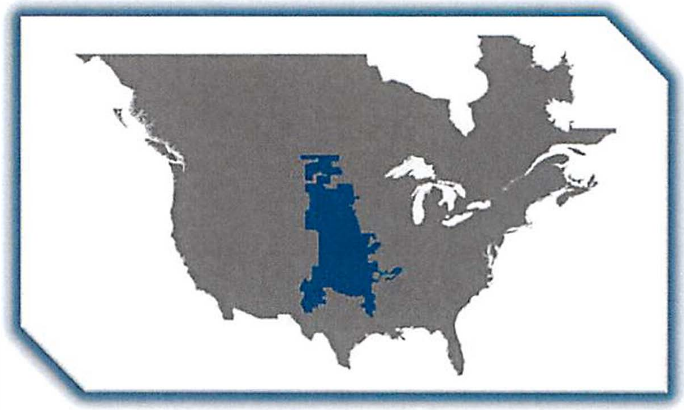
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar.	0.000	0	0.000	0	0.000	0	0.000	0
Apr.	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun.	0.000	0	0.000	0	0.000	0	0.000	0
July	0.000	0	0.000	0	0.000	0	0.000	0
Aug.	0.000	0	0.000	0	0.000	0	0.000	0
Sept.	0.000	0	0.000	0	0.000	0	0.000	0
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.000	0
Dec.	0.000	0	0.000	0	0.000	0	0.000	0
Annual	0.000	0	0.000	0	0.000	0	0.000	0

SERC-SE

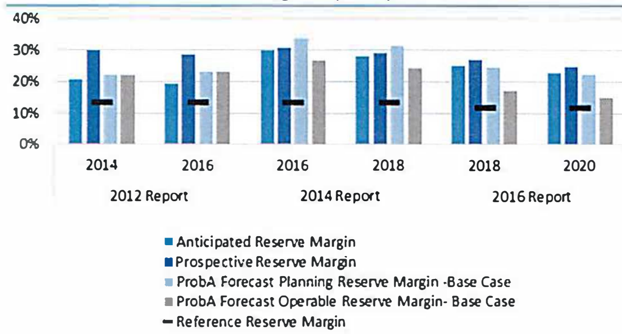
Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0.000	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar.	0.000	0	0.000	0	0.000	0	0.000	0
Apr.	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun.	0.000	0	0.000	0	0.000	0	0.000	0
July	0.000	0	0.000	0	0.000	0	0.000	0
Aug.	0.000	0	0.000	0	0.000	0	0.000	0
Sept.	0.000	0	0.000	0	0.000	0	0.000	0
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.000	0
Dec.	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**	**0.000**	**0**

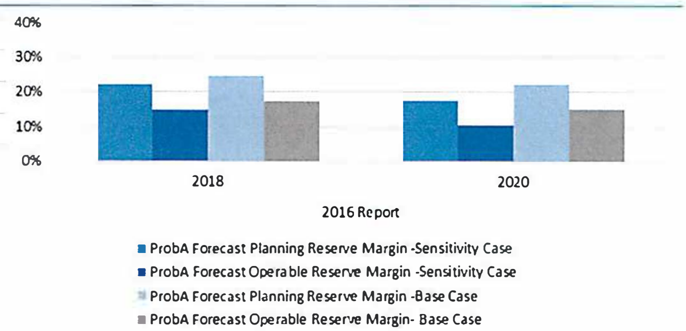
SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 575,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. The SPP Long-Term Assessment is reported based on the Planning Coordinator footprint, which touches parts of the Southwest Power Pool Regional Entity, Midwest Reliability Organization Regional Entity, and Western Electricity Coordinating Council. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of 18 million people.

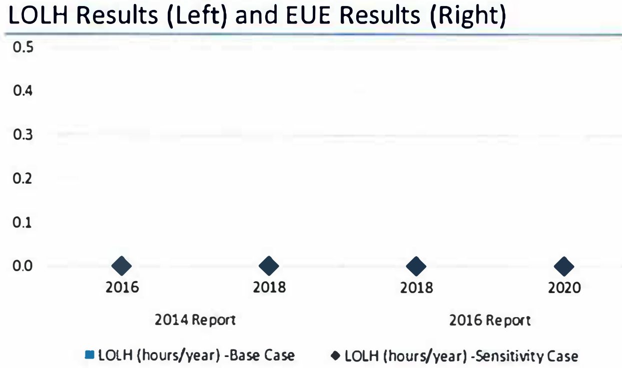


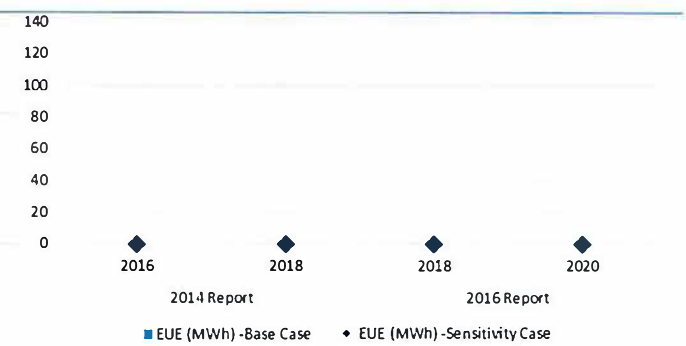
Base Case Reserve Margins (Left) and Probabilistic Measures (Right)





LOLH Results (Left) and EUE Results (Right)





SPP used GridView 9.2 software to perform the analysis including transmission model which allows for realistic power delivery based on actual modeled limits on transmission lines imported from powerflow models. Some other features available in this program include contingency constraints, nomograms, and emergency imports. A sequential Monte Carlo simulation was used to perform the analysis of the SPP reliability assessment. Annual results reflect zero loss of load events, the monthly LOLH, LOLE, and EUE values for 2018 and 2020 were zero as well. The sensitivity case for both study years resulted in no loss of load events.

The 2014 Probabilistic Assessment results for SPP indicated 0.0 EUE and 0.0 Hours/year LOLH for years 2016 and 2018. The 2014 Probabilistic Assessment Base Case results for 2018 were the same for the 2016 Base Case results. Also, the ProbA Forecast Planning reserve margin for the 2018 study year was 3 percent lower in 2014 compared to 2016.

GridView allows external areas to be modeled in the same fashion as internal areas. The key difference between the two is that external generation is ignored when selecting random outages and external load is not increased by load uncertainty factors during the Monte-Carlo simulations. External transmission, however, was considered for calculating flow on lines. SPP assumes zero nonfirm support from external regions. The external capacity modelled was provided as firm capacity which is reflective of the values provided in the 2016 LTRA.

There are three reasons the reported 2016 LTRA and simulation demand values are different. For the simulation, total internal demand, which excluded the projected available demand response, was used with demand response being explicitly modeled as generation, as described in section 4f. Secondly, GridView only allows for the adjustment of the annual peak demand, which occurs during the summer for SPP. When the annual peak is adjusted, the winter peak and every other hour will be adjusted by a proportional amount, based on the hourly load profile. This functionality prevents the winter peak value from aligning with what is provided in the LTRA. Lastly, the total internal demand reported in the LTRA is the aggregation of multiple peaks from entities within SPP. To produce an SPP coincident peak, a 96.6 percent peak demand ratio was applied to the noncoincidental peak demand. This diversity factor was derived from six years of historical hourly load data. The difference between the net energy and the LTRA is also attributable to the proportional adjustment of the hourly load profile.

A 96.6 percent peak demand ratio was applied to the forecasted total internal demand for 2018 and 2020 provided in the LTRA to produce a SPP coincident peak. The 96.6 percent peak demand ratio was derived from 2007-2012 historical hourly load profiles. Each year's noncoincident peak was divided into the coincident peak demand to produce demand ratios. The averaged ratio was applied to the SPP peak load hour for simulation. The total internal demand for 2018 and 2020 is based on a 50/50 forecast and no out-of-region load was modeled in this assessment.

Behind-the-meter generation is generally netted and modeled with customer load. If the behind-the-meter generation is not netted, then it was modeled as regular generation. If the behind the meter generation was not tied to its own bus, then the capacity was divided between its associable generation units within the power flow model.

For this Probabilistic Assessment, it was assumed that SPP does not rely on nonfirm assistance from resources outside of the SPP assessment area footprint, consistent with the LTRA report's values. SPP assumes zero nonfirm support from external regions. The external capacity modelled was provided as firm capacity which is reflective of the values provided in the 2016 LTRA.

Base Case Study

Base-case simulations included foregoing any operating reserves within SPP. No additional operating procedures were included in the analysis. No loss of load events were indicated for the base case study due to a surplus of capacity in the SPP assessment area. Reserve margins are well above 20 percent in both study years and no major impacts were observed related to resource retirements.

Sensitivity Case Study

The sensitivity case for both study years resulted in no loss of load events. Since the annual results for the sensitivity case reflect zero loss of load events, the monthly LOLH, LOLE, and EUE values for 2018 and 2020 were zero as well.

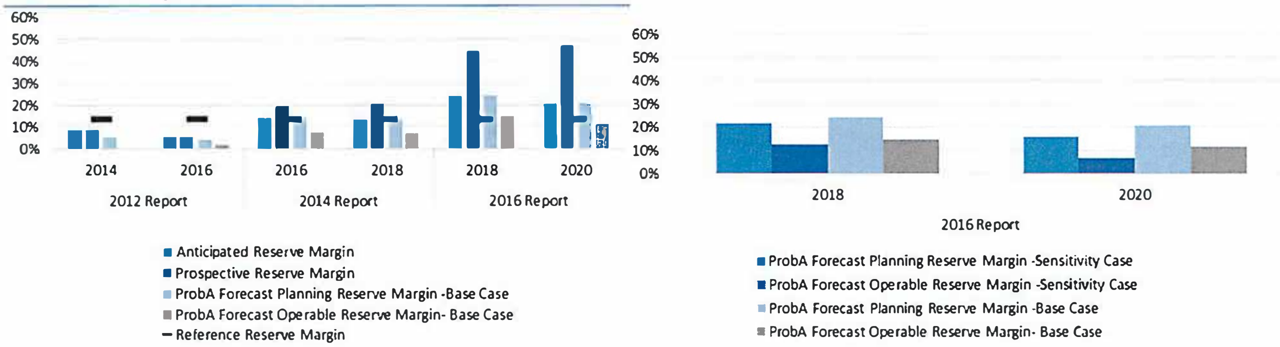
Monthly Reliability Measures

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0
Annual	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0

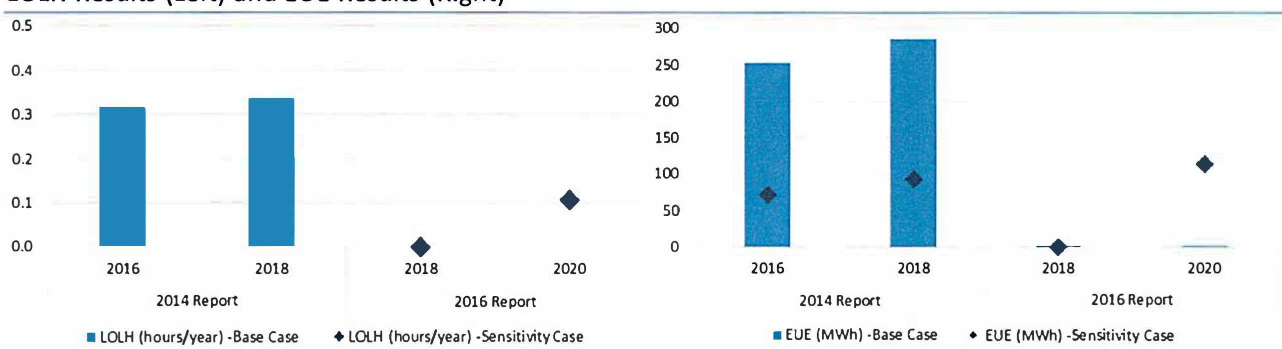
TEXAS-RE –ERCOT

The Electric Reliability Council of Texas (ERCOT) is the Independent System Operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. ERCOT is a summer-peaking Region that covers approximately 200,000 square miles, connects 40,530 miles of transmission lines and 566 generation units, and serves 23 million customers. The Texas Reliability Entity (Texas RE) is responsible for the RE functions described in the Energy Policy Act of 2005 for the ERCOT Region.

Base Case Reserve Margins (Left) and Probabilistic Measures (Right)



LOLH Results (Left) and EUE Results (Right)



This study used Astrapé Consulting's probabilistic resource adequacy assessment model called SERVM (Strategic Energy and Risk Valuation Model), which captures the uncertainty of weather, economic growth, unit availability, and external assistance from neighboring regions as stochastic variables.

The reserve margins for 2018 and 2020 are 24.35 percent and 21.77 percent, respectively. As a result, 2018 has fewer loss of load events compared to 2020. Compared to the 2018 results for the 2014 PRA Assessment, LOLH decreased from 0.338 to 0.000004 while EUE decreased from 285.59 MWh to 0.005 MWh. These reductions are due to an increase in the anticipated reserve margin from 13.6 percent to 24.35 percent for the 2018 forecast year. This reserve margin increase is attributable to both a lower peak load forecast as well as an increase in anticipated resources relative to those included in the 2014 PRA.

To capture weather-related load uncertainty within the ERCOT Region, thirteen historical weather years were utilized. 2011 had an extreme amount of EUE relative to other years due to anomalous weather; as a result, the 2011 weather year was only given a 1 percent probability of occurrence for the simulations.

ERCOT Region is a summer peaking system, the winter forecast is substantially lower than the summer forecast. To capture load uncertainty within the ERCOT Region, thirteen historical weather years were simulated with five different economic load forecast multipliers resulting in 65 full-year load scenarios.

Interruptible load and demand response resources are captured as resources with specific price thresholds at which each resource is dispatched. These resources are also modeled with call limits and priority.

The winter and summer capacity ratings are based on ERCOT's *2016 LTRA* data submission. The summer capacity credit for coastal wind is 55 percent and 12 percent for noncoastal wind. (Coastal wind covers resources located in eleven contiguous counties that border the Gulf Coast.) The winter capacity credit for coastal wind is 35 percent and 20 percent for noncoastal wind. All solar is given an 80 percent capacity credit in the summer and 5 percent in the winter. ERCOT developed these capacity credit values using a multi-year average of historical unit output during the highest peak load hours for each applicable season. Conventional resources are not discounted for expected forced outages.
For hydro resources, 13 years of historical monthly hydro energies and capacities are modeled. A relationship determined from a comparison of total monthly hydro energy and daily hydro dispatch parameters is used to define monthly inputs in SERVM.

As noted above, SERVM captures the transmission system using a transportation/pipeline representation allowing energy to be shared among all zones. ERCOT was treated as a single zone for the 2016 assessment since the 2014 results showed virtually no difference in reliability metrics between multi-zone and single zone analyses. (The 2014 probabilistic study used three internal zones defined using power transfer capability analysis for 2016 and 2018.) An external region was modeled with no load and 1,250 MW of generation to reflect the aggregate net import capability of the five DC ties connected to the SPP and Mexican grids. These resources were given a probabilistic distribution to reflect a range of purchase availability that calibrated with historical purchase activity.

The external region consisted of five generators totaling 1,250 MW of generation capacity and no load assumptions, these resources were each given a 63 percent EFOR. The 1,250 MW is the transfer capability of the DC ties between ERCOT and external regions. The 63 percent EFOR is intended to represent the expected flows across the ties, with the ties being represented in the model as a pseudo resource.

Base Case Study

For the Base Case study, EUE and LOLH values were insignificant due to Planning Reserve Margins exceeding 20 percent for both forecast years. Loss of load occurred only during the summer season, with the majority in August. For example, in 2018, 78 percent of the EUE occurred in that month. Relatively high values in June are driven by the 2012 weather year used to produce the load forecast. The second highest annual peak load from 2002 through 2014 occurred in June 2012.

Sensitivity Case Study

The results show that as the reserve margin falls below 20 percent (which remains well above the target reserve margin used for the *2016 LTRA*), EUE remains low but begins to increase exponentially.

Monthly Reliability Measures

Month	2018 Base		2020 Base		2018 Sensitivity		2020 Sensitivity	
	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)	LOLH (hrs./month)	EUE (MWh/month)
Jan	0.000	0	0.000	0	0.000	0	0	0
Feb	0.000	0	0.000	0	0.000	0	0.000	0
Mar.	0.000	0	0.000	0	0.000	0	0.000	0
Apr.	0.000	0	0.000	0	0.000	0	0.000	0
May	0.000	0	0.000	0	0.000	0	0.000	0
Jun.	0.000	0	0.000	0	0.000	0	0.042	44
July	0.000	0	0.000	0	0.000	0	0.008	8
Aug.	0.000	0	0.000	0	0.000	0	0.057	61
Sept.	0.000	0	0.000	0	0.000	0	0.001	1
Oct.	0.000	0	0.000	0	0.000	0	0.000	0
Nov.	0.000	0	0.000	0	0.000	0	0.000	0
Dec.	0.000	0	0.000	0	0.000	0	0.000	0
Annual	**0.000**	**0**	**0.001**	**0**	**0.000**	**0**	**0.107**	**114**

WECC

The Western Electricity Coordinating Council (WECC) is responsible for coordinating and promoting BPS reliability in the Western Interconnection. WECC's 329 members, which include 38 BAs, represent a wide spectrum of organizations with an interest in the BPS. Serving an area of nearly 1.8 million square miles and approximately 82.2 million people, it is geographically the largest and most diverse of the NERC regional reliability organizations. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico, and all or portions of the 14 western states in between. The WECC assessment area is divided into five subregions: Rocky Mountain Reserve Group (RMRG), Southwest Reserve Sharing Group (SRSG), California/Mexico (CA/MX), and the Northwest Power Pool (NWPP), which is further divided into the BC, AB, and NW-US areas. These subregional divisions are used for this study as they are structured around Reserve Sharing groups that have similar annual demand patterns and similar operating practices.

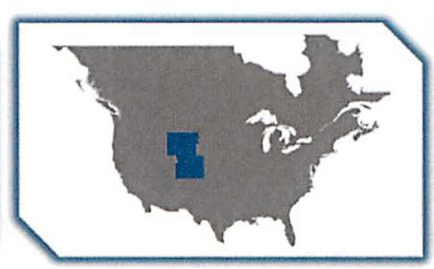
WECC-BC

WECC-CA/MX

WECC-AB

WECC-NWPP-US

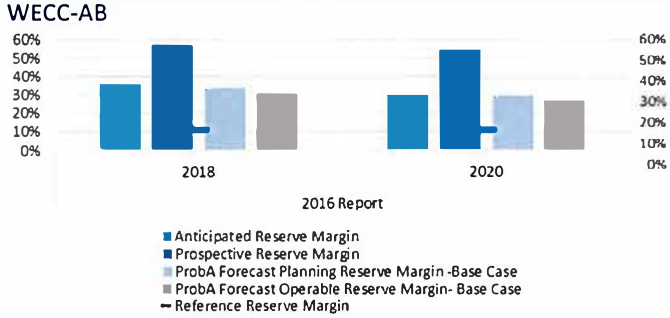
WECC-RMRG

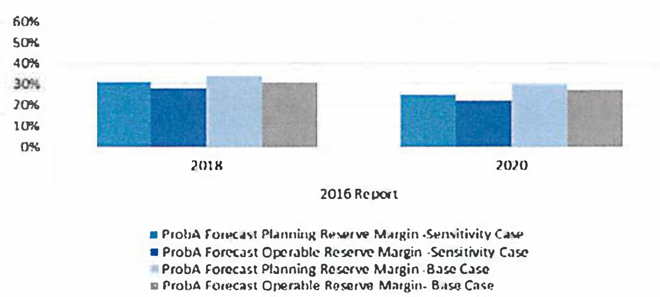


WECC-SRSG

Base Case Reserve Margins (Left) and Probabilistic Sensitivity Measures (Right)

WECC-AB





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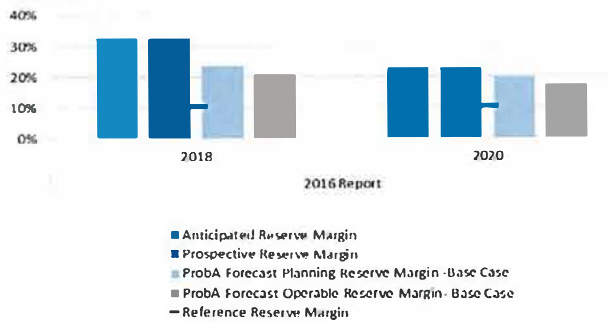
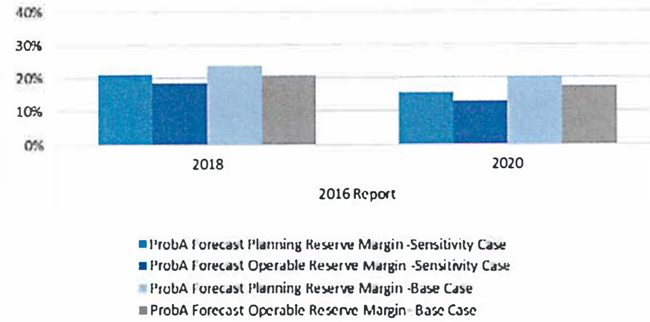
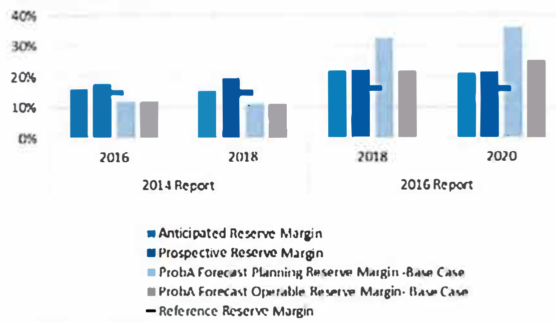
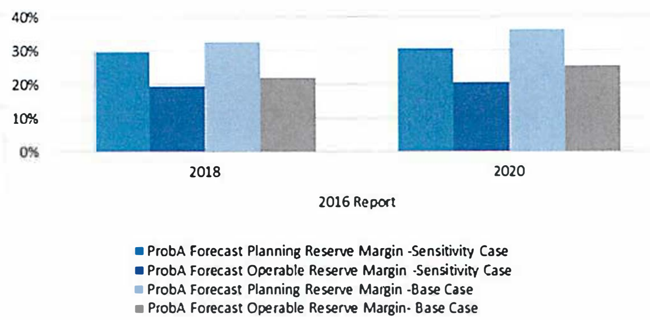


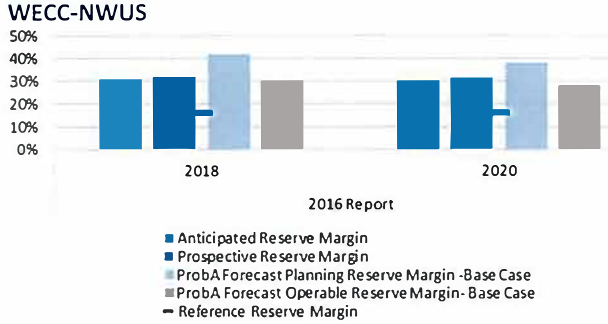


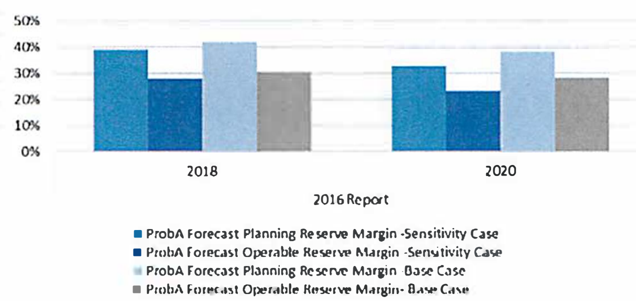
WECC-CAMX





WECC-NWUS





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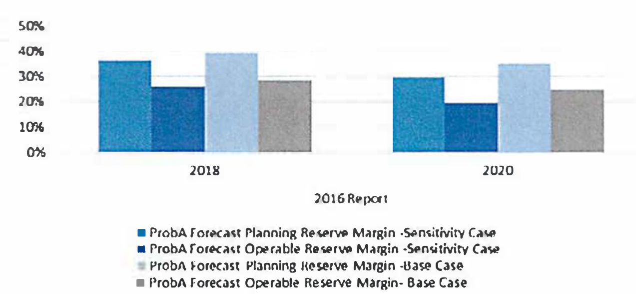
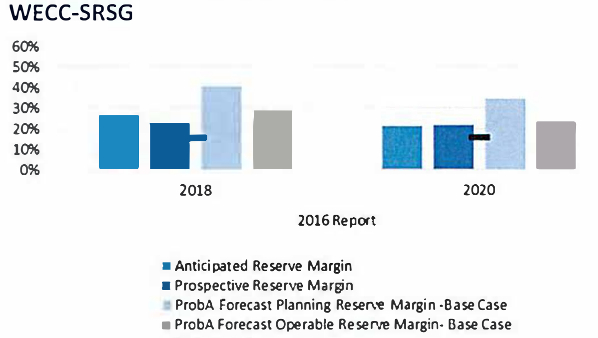
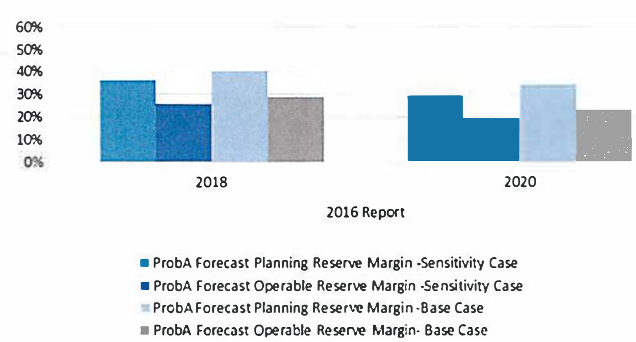


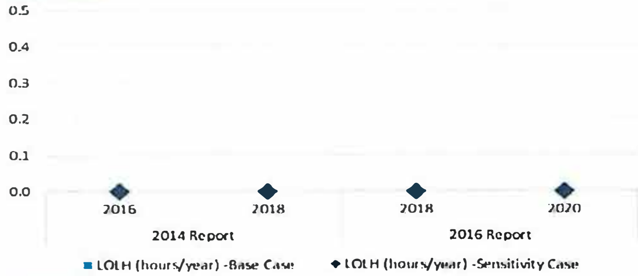
WECC-SRSG



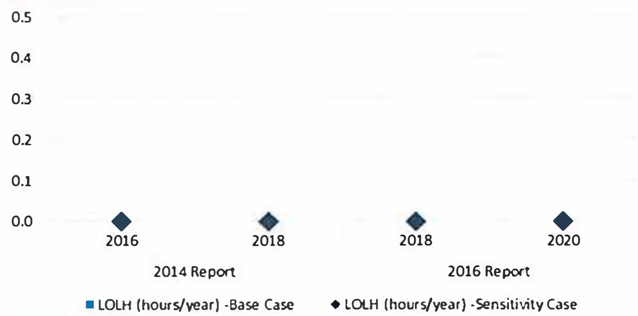


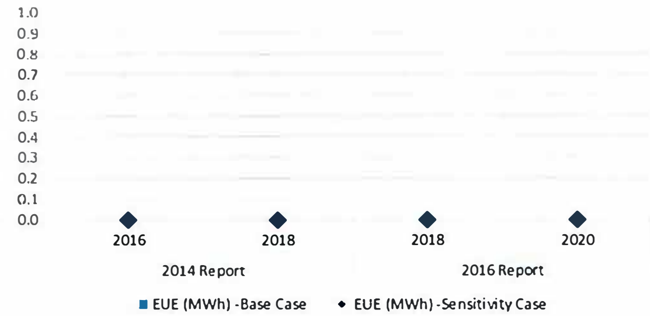
LOLH Results (Left) and EUE Results (Right)

WECC-AB

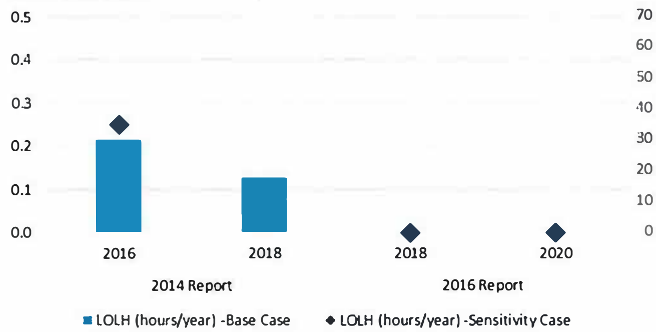


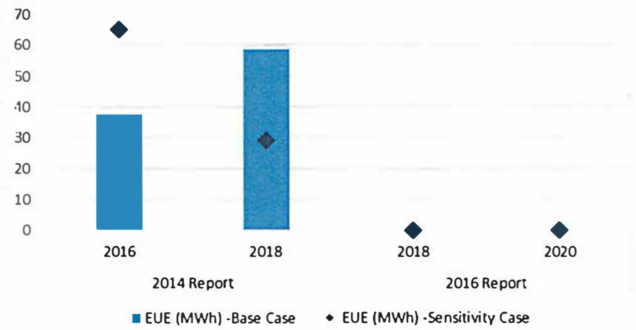
WECC-BC



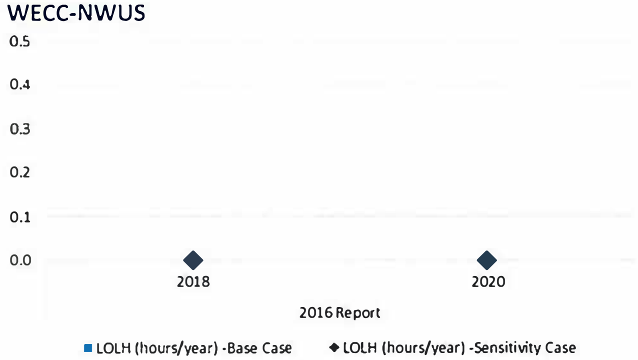


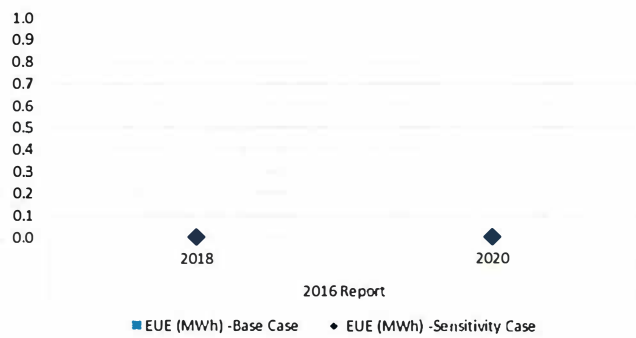
WECC-CAMX



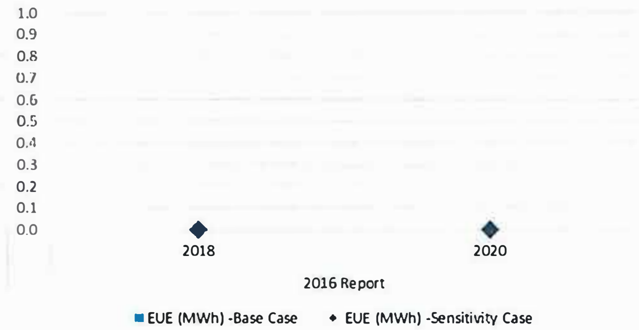


WECC-NWUS

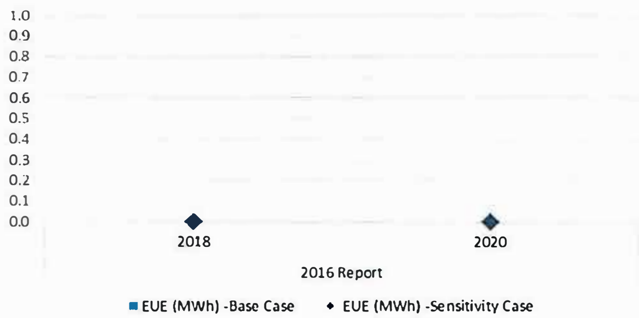




WECC-RMRG



WECC-SRSG



WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) Model, an in-house probabilistic application, to perform the probabilistic analysis for study years 3 and 5, 2018 and 2020, respectively. MAVRIC is designed as a convolution model that examines the probability distributions of the input variables in the model and balance the system instead of running the model to produce frequency distributions of the output by randomly drawing values from the input distributions. The model allows for the loss-of-load probability of the system to be measured on an hourly basis without the need for iterations and computational run time.

Based upon the given LTRA values, no loss of load was shown in the WECC footprint for 2018 and 2020. Since the annual results reflect zero loss of load events, the monthly LOLH, LOLE, and EUE values for 2018 and 2020 were zero as well. The sensitivity case for both study years resulted in no loss of load events.

To determine the distributions for the load forecast uncertainty, seven years of historical data (from 2007 to 2013) were used. Starting with the first hour of the year, the same hours for each of the three weeks prior to the given hour and for each of the three weeks following the given hour, as well as the current hour itself were used to determine the variability around the mean of the sample.

Consistent with the LTRA, demand response was not included in the analysis as either a resource or load modifier as a conservative analysis.

Consistent with the LTRA, the expected transfer capability between demand areas was modeled. If, on a given hour, a demand area had excess energy, the availability and demand distributions did not overlap, then the excess energy was made available to neighboring areas.

Modeling of variable resources was determined by constructing separate hourly variability distributions for each of hydro, wind, solar-fueled resources using 5 years of historical data (from 2009 to 2013). The variable resource models where then applied to the capacity associate4d with the LTRA.

The Western Interconnection does not have import capability from other Interconnections.

The sensitivity case for both study years resulted in no loss of load events. Since the annual results for the sensitivity case reflect zero loss of load events, the monthly LOLH, LOLE, and EUE values for 2018 and 2020 were zero as well.

Appendix I: Assessment Preparation, Design, and Data Concepts

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Atlanta, GA 30326
404-446-2560

Washington, D.C.
1325 G Street NW, Suite 600
Washington, DC 20005
202-400-3000

Assessment Data Questions

Please direct all data inquiries to NERC staff (assessments@nerc.net). References to the data and/or findings of the assessment are welcome with appropriate attribution of the source to the NERC *2016 Probabilistic Assessment*. However, extensive reproduction of tables and/or charts will require permission from NERC staff.

NERC Reliability Assessment Staff

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Thomas H. Coleman	Director, Reliability Assessment
Amir Najafzadeh	Senior Engineer, System Analysis
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Elliott J. Nethercutt	Senior Technical Advisor, Reliability Assessment
Nicole U. Segal, PhD	Engineer of System Analysis
Noha Abdel-Karim, PhD	Senior Engineer, Reliability Assessment
Levetra Pitts	Administrative Assistant, Reliability Assessment and System Analysis

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Name	Representing	Name	Representing
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Alan Wahlstrom	Southwest Power Pool, Inc.	Michael Courchesne	ISO New England, Inc.
Binod Shrestha	SaskPower	Peter Warnken	ERCOT
Chris Haley	Southwest Power Pool, Inc.	Peter Wong	ISO New England, Inc.
Denise Lam	Florida Reliability Coordinating Council	Richard Becker	Florida Reliability Coordinating Council
Helve Saarela	ISO New England, Inc.	Richard Kinas	Orlando Utilities Commission
Hubert Young	South Carolina Electric & Gas Co.	Ryan Egerdahl	Bonneville Power Administration
James Leigh-Kendall	Sacramento Municipal Utility District	Salva Raja Andiappan	Midwest Reliability Organization
Jeffrey Harrison	Associated Electric Cooperative, Inc.	Sennoun Abdelhakim	Hydro-Québec
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Layne Brown	Western Electricity Coordinating Council	Teresa Glaze	SERC Reliability Corporation
Lewis De La Rosa	Texas Reliability Entity, Inc.	Vithy Vithyananthan	Independent Electricity System Operator

Appendix II Detailed Probabilistic Modeling Table

Link to Detailed Probabilistic Modeling Table www.nerc.com

Appendix III –Methods and Assumptions Table

		NPCC	PJM	SERC	FRCC	MISO	Manitoba	Sask.	SPP	ERCOT	WECC
Model Used	Name	GE MARS	GE MARS	GE MARS	TIGER	GE-MARS	GE MARS	MARS	GridView	SERVM	MAVRIC
	Model Type	Monte Carlo	Monte Carlo	Monte Carlo	Convolutio n	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Monte Carlo	Convolution
	# Trials	1,000*10*7	1,000*7	1,000*7*7	500	50000 * 7	10000	20000 x 7	4000	300 x 13 x 5 = 19,500	N/A
	Total Run Time	2 hours * 72 CPUs	2 hours * 72 CPUs	50 min * 50 CPUs*7*4	30 Minutes	3 Hours	35 min	0.5 hours	96 hours/study	2 hours on 65 CPUs	N/A
Load	Internal Load Shape	Typ. Yr. 2002 and 2004	Typ. Yr. S-2002; W-2004	07 yrs; 2007-2013; Risk-based weighted load shapes	Synthetic Year: from 10+ years	Typical Year 2005 for North/Central; 2006 for South	Typical year 2002	Peak(2008)	One year load shape; Highest energy and peak output for years 2007 - 2012, 2011	13 weather years 2002-2014	2004-2014
	External Load Shape	Typ. Yr. 2002 and 2004	Typ. Yr. S-2002; W-2004	MISO North-Typ. Yr. 2005; MISO South-Typ. Yr. 2006; PJM- Typ. Yr. 2002; FRCC-Typ. Yr. 2005; SPP- Typ. Yr. 2005	N/A	N/A	Typical year 2002	None	N/A	N/A	N/A
	Adjustment to Forecast	Monthly Peak & Energy	Monthly Peak	Monthly Peaks and Energy	Monthly Peaks and Energy for up to 2018; Seasonal Peak for 2018+	Monthly Peaks	Monthly Peak & Energy	Monthly Peaks and Energy	Annual Peak	The average summer peak of 13 load shapes was scaled to the summer forecast. Same for winter peak.	N/A

Load Forecast Uncertainty	**Modeling**	7-step Discrete Distribution	7-step Discrete Distribution	19 Historic Years (18 Y-1 data points); Assumed weather uncertainty; normal distribution; 7 multipliers (3 sigma either side mean) Seasonal-Summer, Winter, Spring, Fall-LFU modeled	Not Modeled	7 discrete steps normally distributed capturing weather and economic uncertainty	7-step Discrete Normal Distribution, weather	Normal Distribution	7 discrete steps	13 weather years x 5 load forecast uncertainty multipliers = 65 load scenarios	3%-97% probability distribution
	90th %ile (% above 50/50 peak)	Varies by Area; asymmetrical	2018-7.6%; 2020-7.8%	Summer: 5.13% at 90%ile (1.28 Standard Deviation); Winter: 10.25% at 90%ile (1.28 Standard Deviation);	2018 - 2.3% 2020 - 2.9%	5.11%	2018-3.9% 2020-5.2%	2020-2.6%; 2018-2.6%	6% at 90%ile	2018: 4.3% 2020: 4.5%	Varies by Region
	Uncertainties Considered	weather, economic, forecast	Weather, Economic, Forecast	Weather Forecast	Weather, economic, forecast	Weather and Economic	Weather, economic, forecast	Weather, Economic	weather, forecast	Weather and Economic Forecast Error	Weather and Economic Variability
Behind-the-Meter	Percentage of Peak Load at Peak	Unknown	2018-2%; 2020-3.5%	Minimal; ~1%	Unknown	N/A	N/A	0	Unknown	0.08	N/A
	Thermal Generation	Resource	Netted From Load	Within the load	Netted from Load	Resource	N/A	N/A	Within the load	Resource	N/A

	Variable Generation	Resource	Netted From Load	Within the load	Netted from Load	Resource	N/A	N/A	Within the load	Netted from Load	N/A
	Demand Manageme nt	N/A	Netted From Load	Within the load	N/A	Resource	NA	N/A	Within the load	N/A	N/A
Demand-Side Management	Modeling	Dispatchable resource, Operating procedure (varies by area)	Operating procedure	Energy-Limited Resources	Load Modifier	Energy-Limited Resource	Load Modifier	DSM adjusted Load Forecast	Dispatchable Resource	Dispatchabl e, Energy-Limited Resource	N/A
	Load shape / Derates /FOR	N/A	N/A	Monthly Probability Distribution Curves / FOR	Not derated for use	Count and Duration Limited	Reduction in Peak	None	Available for 6 hours on each daily peak	Hourly Limits Per Season and by Year	N/A
	Correlation to load	When modeled as EOP (varies by area)	Not modeled	Not Modeled	N/A	not explicitly modeled	NA	None	not modeled	Dispatched based on shadow price	N/A
Variable Generation - Wind	Modeling	Resource, Fixed resource	Resource	Load Modifier	None	Load Modifier	Resource	Load Modifier	Resource	Energy-Limited Resource	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Hourly Shape	N/A	Modeled at capacity credit value	NA	Weekly	hourly shape	Hourly Shape for 13 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Consistent with load (time series)	N/A	Not Modeled	Consistent with load	Not Modeled	Match load	Consistent with load	N/A
	Capacity Value	0% to 35% (varies by area)	13%	Approx. 19% during peak	N/A	By wind farm. MISO System Capacity Credit is 15.6%	20% winter and 16% summer	20% Win 10% Sum	0% to 25% of nameplate, Area dependent	Sum: 55% coastal; 12% noncoastal Win: 35% coastal, 20% noncoastal	Varies by Region

Variable Generation - Solar	**Modeling**	Resource	Resource	Load Modifier	Dispatchable Resource	Load Modifier	None	None	Resource	Energy-Limited Resource	Energy Limited Resource
	Load shape / Derates /FOR	Hourly shape, Monthly	Modeled at Capacity Value	Hourly Shape	At minimum firm capacity	Modeled at capacity credit value	NA	N/A	hourly shape	Hourly Shape for 13 years matching load profile	Hourly Shape
	Correlation to load	Consistent with load, Not modeled	Not Modeled	Consistent with load (time series)	Not Modeled	Not Modeled	NA	N/A	2011 Solar Shape	Consistent with load	N/A
	Capacity Value	Not specified	0% Winter; 38% Summer	Approx. 36% during peak	N/A	MISO System Capacity Credit is 50%	NA	N/A	10% to 95% of nameplate, Area dependent	Summer: 80% ; Winter: 5%	Varies by Region
Hydro - Electric Generation	Modeling	Energy Limited Res., Dispatched after Thermal	Resource	Energy Limited Resource, 20% Dispatched and remainder available as emergency assistance	Dispatchable resource	Resource unless Run-Of-River. Run-of-River submit 3 years of historical data at peak	Energy Limited Resource	Energy Limited Resource, Peak Shaving	Energy Limited Resource	Energy Limited Peak Shaving Before Thermal and Emergency Component	Energy Limited Resource
	Energy Limits	Average	N/A	Average 10 years monthly output	N/A	Summer Months, Peak Hours 14 - 17 HE	Different below average water conditions including extreme drought	Median	Yearly Energy Limitation based on historical performances	13 years of historical hydro conditions were modeled 2002-2014	Hourly Shape
	Capacity Derates	Monthly	Monthly	Monthly	Firm Capacity	At Firm Capacity	Monthly	Monthly	Monthly	Monthly values	N/A
	Planned Outages	Model schedule, Within Capacity Derates	Model scheduled	Model scheduled	Not Modeled	Model Scheduled	Not modeled	First five years are scheduled maintenance. Remaining is scheduled by program.	Not modeled	Netted out based on modeling actual monthly hydro energies	Varies by Region

	Forced Outages	Monte Carlo, Not modeled (varies by area)	Monte Carlo	Not Modeled	GADS average	Monte Carlo, Run-of-River has none	N/A	Not Modeled	Not modeled	N/A	N/A
Thermal Generation	**Modeling**	MC; 2 state - some areas up to 7-state	MC; 2-state	MC; 2-state	Convolution	MC; 2-state	MC 2-state	MC up to 5 state	MC; 2-state	MC; Up to n-state	2-State 3%-97% Probability Distribution
Thermal Generation	**Energy Limits**	None	None	None	None	None explicitly	None	None	None	None	None
Thermal Generation	**Capacity Derates**	Monthly	Monthly	Equivalized Annual Average	Seasonal	Monthly	Monthly	Monthly, Monthly derates inputted into the model	Consideration of Capacity Derates in random forced outage variable during Simulation	Monthly	Seasonal
Thermal Generation	**Planned Outages**	By model, External Input	By Model	By Model (Planned Outage Rate-Optimized	External Input	By Model	By Model	By Model & Manual Input	by Model & Manual Input	By Model	By Model
Thermal Generation	**Forced Outages**	EFORd	5 yr EEFORd	EFORd	Forecasted FOR based on actuals applied to individual unit	5 yr unit specific EFORd	EFORd	5-year historical average	EFORd	5 year EFOR from ERCOT's Outage Scheduler Data; Units are economically dispatched in SERVM	Historical 12 year EFOR
Firm Capacity Transfers	Modeling	Explicitly Modeled	Explicitly Modeled	Explicitly Modeled-Modeled as perfect pseudo-tied units (neg (-) from seller and pos (+) for purchaser)	Imports treated as resource; Exports not modeled	Imports treated as Resource; Exports derated from monthly unit capacities	Imports treated as resource, Exports added as load	Import treated as load modifier	Explicitly Modeled	Not Modeled	Explicitly Modeled

	Hourly Shape Issues	None	None	N/A	N/A	None	Weekly capacities	Hourly Load modification for a typical week.	None	N/A	N/A
	Capacity Adjustments - Transmission Limitations	None	None	N/A	N/A	None	None	N/A	N/A	N/A	N/A
	Transmission Limit Impact of Firm Transfers	Impact derived within model	Endogenously modeled	Limits adjusted	N/A	None	Accounted for in interface limits	N/A	Accounted for in interface limits	N/A	N/A
	Forced Outages	N/A	No	By Contract	Yes	5 yr unit specific EFORd	No	No	No	N/A	N/A
Internal Representation	Assessment Areas	5	1	3	1	1	1	1	1	1	6
	Total Nodes	56	5	4	1	10	1	1	Detailed bus modeling; Approximately 650 generator buses and 4,500 load buses	1	49
	Node Definition	Determined by potentially limiting transmission interfaces	Market-Defined Regions	2 Assessment Areas = 2 Nodes; 1 Assessment Area = 2 nodes defined by Balancing Authority boundaries	N/A	Local Resource Zone	N/A	N/A	Load and Generation modeled at bus level from powerflow model	N/A	Balancing Authority
	Transmission Flow Modeling in ProbA Model	Transportation/Pipeline	Transportation/Pipeline	AC/DC in PSSE, Transportation/ Pipeline in MARS	N/A	Transfer Analysis Import/Export Limit for each Local	Transportation/ Pipeline	N/A	DC Load Flow	N/A	Transportation/Pipeline

						Resource Zone					
	Transmission Limit Ratings	NY and Maritimes - short-term emergency; all other - normal	Short-term Emergency	normal and short-term emergency ratings	N/A	N/A	Normal	N/A	Long-Term Emergency	N/A	Normal
	Transmission Uncertainty	Selected Lines	No	No	N/A	No	No	N/A	No	N/A	No
External Representation	**# Connected Areas**	3	4	7	1	7	1	3	2	3	0
External Representation	**# External Areas in Study**	8	4	10	0	7	1	0	5	3	0
External Representation	**Total External Nodes**	8	59	10	0	1	1	N/A	Detailed bus level powerflow modeling	1	0
External Representation	**Modeling**	Detailed	Detailed and At planning reserve margin	Detailed	N/A	Less Detailed	Detailed at their Planning Reserve Margin	N/A	Detailed; source/sink for transfers	Source for transfers	0
Other Demands	**Operating Reserve**	Yes	Yes	No	No	No	Not Considered	Yes	Yes	Yes	No
Operating Procedures (pre LOL)	**Forgo Operating Reserve**	OR to 0 in all Areas except Québec and New England.	Fully	Fully	N/A	N/A	N/A	Fully	Fully	Partially	Fully
Operating Procedures (pre LOL)	**Other**	DR, public appeals, voltage reductions	DR, 30-min reserves, voltage reduction, 10-min reserves, public appeals	Reduce OR; RSG Purchases	None	None	None	Demand Response, Emergency	DR	DR and Emergency Thermal Generation	None

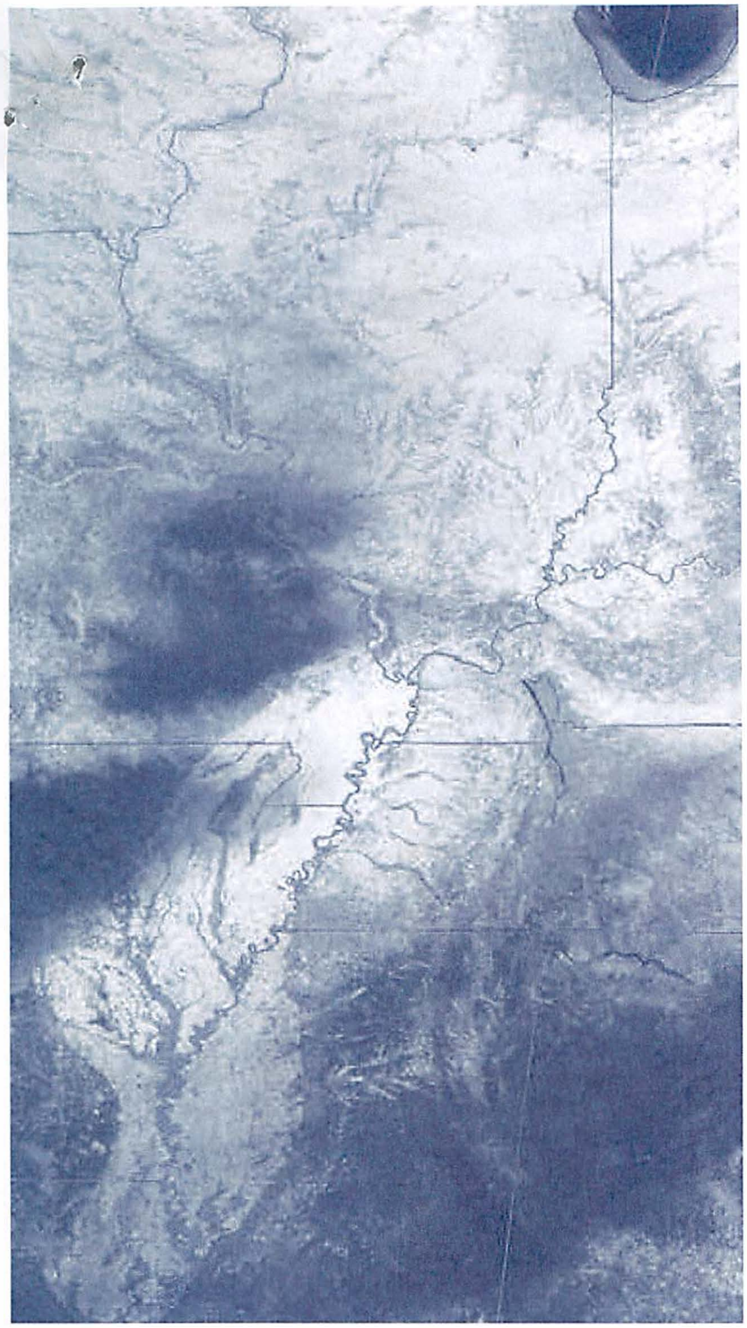
Appendix IV ProbA Data Forms

Link to annual and monthly reliability measures and statistics will be found at www.nerc.com

Appendix V Detailed Report by Region or Assessment Area

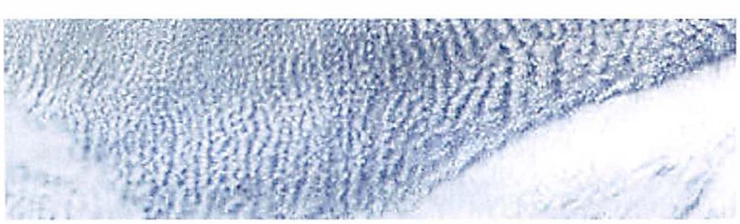
Link to Regions and Assessment Areas' full Probabilistic Assessment Reports

www.nerc.com



2019 FERC and NERC Staff Report

The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018



FERC and NERC Staff Report
July 2019

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

FERC and NERC Staff Report July 2019

This report was prepared by the staff of the Federal Energy Regulatory Commission in consultation with staff from the North American Electric Reliability Corporation and its Regional Entities.

This report does not necessarily reflect the views of the Commission.

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Acknowledgement

This report[1] results from the combined efforts of many dedicated individuals in multiple organizations. The team behind the report (the Team) consisted of individuals from the Federal Energy Regulatory Commission (FERC or the Commission), the North American Electric Reliability Corporation (NERC), Regional Reliability Entities Midwest Reliability Organization (MRO), SERC Corporation (SERC), ReliabilityFirst Corporation (RF), and Western Electricity Coordinating Council (WECC),[2] all of whom are named in Appendix A. They were assisted by other non-Team members within their respective organizations. The inquiry which led to the report arose out of two presentations describing the January, 2018 event to FERC Staff: one by Midcontinent Independent System Operator, Inc. (MISO), and the other a combined presentation by Southwest Power Pool, Inc. (SPP), Tennessee Valley Authority (TVA), and the Southeastern Reliability Coordinator (SeRC)/Southern Company (SoCo), as well as other Joint Parties to a settlement between MISO and SPP, namely Associated Electric Cooperative, Inc. (AECI), Louisville Gas and Electric/Kentucky Utilities (LG&E/KU),

[1] This report is written for a reader who is already familiar with principles of energy markets, transmission system operations and generation unit operations. For readers who are not as familiar, the Team has provided a variety of appendices which may be helpful. *See, e.g.*, Appendix B, Primer on Electric Markets and Reliable Operations of the Bulk Electric System (BES)(begins at page 104), Appendix C, Reliability Coordinator and Transmission Operator Tools and Actions to Operate the BES (begins at page 109), Appendix D, Glossary of Terms Used in the Report (begins at page 114), Appendix E, Categories of NERC Registered Entities (begins at page 123), and Appendix F, Acronyms Used in the Report (begins at page 124). In addition, the Reliability Primer prepared by Commission Staff (https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf) and appendices from the Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations (https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf) may be helpful. Helpful appendices in the 2011 report include: Electricity: How it is Generated and Distributed, Power Plant Design for Ambient Weather Conditions, Impact of Wind Chill [on generating units], Winterization for Generators, Natural Gas: Production and Distribution, Natural Gas Transportation Contracting Practices, and Impact of Cold Weather on Gas Production. Appendix G of this report, which begins at page 126, contains the 2011 report's Recommendations on Preparation for Cold-Weather Events.

[2] Although the Event did not occur in WECC's footprint, WECC was invited to participate due to its experience with issues relating to the "seams" or borders between two Reliability Coordinator footprints.

and PowerSouth. Following these presentations, the Commission and NERC announced a joint inquiry with the Regional Entities, citing, among other factors, "reports of multiple forced generation outages, voltage deviations and near-overloads during peak operations," and the need to "understand and underscore the importance of seamless RC-to-RC interactions."[3]

Without the excellent cooperation of these entities, the Team could never have produced a thorough analysis. In addition to the owners of generating units affected by the extreme weather conditions, the Team would especially like to thank the staffs of MISO, SPP, TVA, SeRC/Southern Company, AECI, LG&E/KU, and PowerSouth. All of these entities provided data, and the non-generator entities attended multi-day meetings to answer questions and share perspectives. Some answered multiple rounds of questions as the Team clarified its understanding of key concepts. All were generous with their data and time, and the Team is grateful.[4] The Team conducted outreach to share its preliminary findings and recommendations. Those invited to outreach sessions included MISO, SPP, TVA, Southern Company, and the Joint Parties, the Regional Entities not already participating in the Inquiry, market monitors for MISO and SPP, and industry groups including the ISO/RTO Council, Edison Electric Institute, the Electric Power Supply Association, the North American Transmission Forum, the North American Generator Forum, the National Rural Electric Cooperative Association, the American Public Power Association, the Electricity Consumers Resource Council, the Canadian Electricity Association, and the Transmission Access Policy Study Group. The Team thanks all who participated in the outreach for their insight.

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[3] https://www.ferc.gov/media/news-releases/2018/2018-3/09-12-18.pdf

[4] The entities provided data to the Team with the assurance that it would be kept confidential until the entities provided permission to release it publicly. The Team has obtained permission from the entities to share the data included in the report.

I. Executive Summary

On January 17, 2018, a large area of the south central region of the United States experienced unusually cold weather. The below-average temperatures in this area resulted in a total of 183 individual generating units within the Reliability Coordinator (RC)[5] footprints of SPP, MISO, TVA,[6] and SeRC experiencing either an outage, a derate,[7] or a failure to start between January 15 and January 19, 2018. Between Monday, January 15, and the morning peak hour (between 7 and 8 a.m. Central Standard Time (CST)) on Wednesday, January 17, approximately 14,000 MW of generation experienced an outage, derate or failure to start. Including generation already on planned or unplanned outages or derated before January 15, the four RCs had over 30,000 MW of generation unavailable in the south central portions of their footprints by the January 17 morning peak hour. MISO declared an Energy Emergency,[8] because it had insufficient reserves to balance generation and load in the MISO South portion of its footprint, while all four of the RCs experienced constrained bulk electrical system (BES)[9] transmission

[5] See Appendix E, "Categories of NERC Registered Entities."

[6] TVA is a Reliability Coordinator for its TVA Balancing Authority area as well as for the Balancing Authority areas of AECI and LG&E/KU. This report will clarify whether it is referring to TVA as the RC, including AECI and LG&E/KU, or only to TVA's own Balancing Authority area.

[7] Reductions in capacity of a generating unit short of a total outage.

[8] See Appendix C, "RC and TOP Tools and Actions to Operate the BES in Real Time."

[9] The Commission's jurisdiction extends to the Bulk-Power System, defined by Section 215(a) (1) of the Federal Power Act as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability." The mandatory Reliability Standards apply to owners and operators of the bulk electric system (BES). In Order No. 773, the Commission approved a definition of BES that generally covers all elements operated at 100 kV or higher, with a list of specific inclusions and exclusions. Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure, Order No. 773, 141 FERC ¶ 61,236 (2012); order on reh'g, Order No. 773-A, 143 FERC ¶ 61,053 (2013), order on reh'g and clarification, 144 FERC ¶ 61,174 (2013). This report will use BES because its primary audience is most familiar with that term.

conditions across portions of their footprints, spanning all or parts of nine states. While the system remained stable, this combination of an Energy Emergency and wide-area constrained transmission conditions on January 17 meant that had MISO's next single contingency generation outage in MISO South of 1,163 MW[10] occurred, continued reliable BES operations would have depended on system operators shedding firm load promptly to prevent further degradation of BES conditions.

The combination of an Energy Emergency and wide-area constrained conditions constitutes the South Central U.S. Cold Weather BES Event of January 17, 2018, hereafter referred to as "the Event," which occurred in an area (the "Event Area")[11] consisting of:

- MISO South (Arkansas, eastern Texas, Louisiana, and Mississippi)
- Southeastern portion of the SPP RC footprint (lower Kansas-Missouri border, the eastern half of Oklahoma, Arkansas, eastern Texas, and Louisiana)
- Western portion of the TVA RC footprint (western Tennessee, lower Missouri, northeastern Oklahoma, northern Mississippi and Alabama)
- Western portion of the SeRC footprint (southern Mississippi and Alabama).

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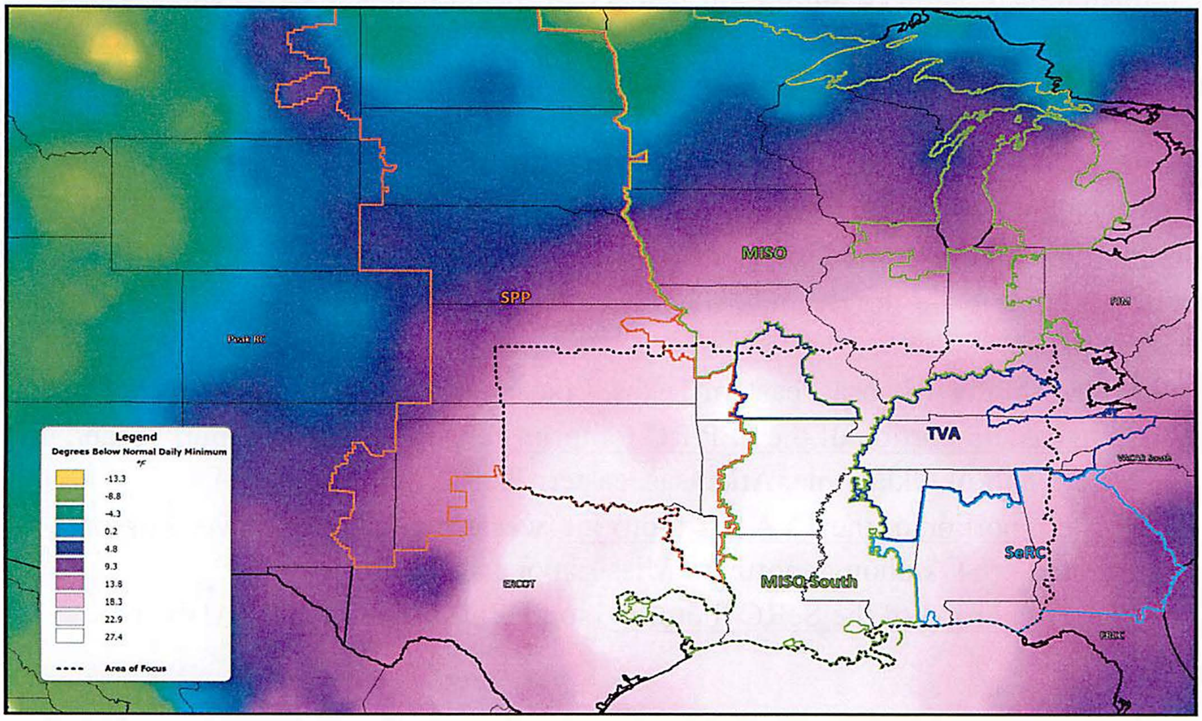
[10] The mandatory Reliability Standards set forth requirements that provide for the reliable operation of the BES. Federal Power Act (FPA) § 215(a)(3). In turn, "reliable operation" is defined in the FPA as "operating the elements of the [BES] within equipment and electric system thermal, voltage and stability limits, so that instability, uncontrolled separation or cascading will not occur as a result of a sudden disturbance, including a cybersecurity incident or unanticipated failure of system elements." *Id.*

[11] The sources or credits for all Figures are listed in Appendix H, "Source of Figures Used in the Report (begins at page 139)."

Figure 1: **January 17, 2018 Event Area – Low Temperature Deviation From the Normal Daily Minimum**



Below-average temperatures began to occur as early as Friday, January 12, from the Great Plains south through the Mississippi Valley. Going into the work week beginning Monday, January 15, MISO, SPP, and the other RCs, which are located within the MRO, SERC, and RF regions,[12] knew that Wednesday, January 17, was likely going to be the coldest day of an extremely cold week for much of their respective footprints. Because their footprints stretch further eastward than SPP's, MISO, TVA and SeRC also expected cold weather conditions for their respective areas on Thursday, January 18, as forecasts showed the cold weather moving eastward. With temperatures forecast by the National Oceanic and Atmospheric Administration to be "much below normal" for January 17, RCs in the Event Area expected very high system loads.

Planned and unplanned generation outages already existed going into the week of January 15, but as the colder weather conditions developed, MISO was projecting extremely tight reserve margins for MISO South in meeting its forecast peak load for the morning of January 17, beginning at 7 a.m. CST. Still, even with a high system load forecast and pre-existing generation outages, MISO did not expect to have a problem

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[12] These are among the Regional Entities to which NERC has delegated some of its duties as the Electric Reliability Organization, as part of the statutory scheme which gave rise to mandatory Reliability Standards.

meeting customer demand on January 17 in MISO South, based on anticipated generator availability and precautionary measures that MISO took to increase projected reserves. However, an extraordinary amount of continuing generation outages and derates increasingly tightened already tight reserves, requiring emergency measures. In addition, MISO's five-day, four-day and three-day-out MISO South load forecasts for January 17 were less accurate (underestimating load by approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW, respectively) than the other RCs' forecasts for the same period. Improved forecasting accuracy for future extreme weather conditions could increase MISO's ability to rely on long-lead-time resources and give it more time to prepare for severe weather events. The Team recommends that MISO work with its Local Balancing Authorities and adjacent RCs to improve the accuracy of its near-term load forecasts for MISO South.

In order to meet forecast load plus reserves for the morning peak hour (7 to 8 a.m.) on January 17, MISO instructed its local balancing authorities (LBAs) in MISO South to issue public appeals to reduce demand.[13] MISO estimated the total load reduction achieved from this effort was 700 MW. Some of the Load Modifying Resources (LMR)[14] participating in MISO's load reduction required more notice than MISO was able to provide at the time of this appeal..[15] MISO also needed to purchase emergency energy from suppliers in adjacent RCs to meet its peak load.

The MISO South footprint was severely stressed as the morning peak hour approached. During the peak hour, MISO system analysis showed that if it incurred the worst single contingency generation outage of 1,163 MW in MISO South (hereafter MISO South WSC),[16] it would need to rely on post-contingency manual firm load shed

[13] MISO attributed the need for public appeals to "forced generation outages and higher than forecast load."

[14] Load Modifying Resources are demand resources or behind-the-meter generation.

[15] On January 18, the day after the Event, when MISO was able to provide more notice, it achieved 930 MW of Load Modifying Resources.

[16] In addition to the Most Severe Single Contingency (MSSC) for its entire BA area (for the morning of January 17, 2018, MISO's MSSC was a 1,732 MW facility in the Midwest region of its BA), which MISO is required to cover under the Reliability Standards, MISO planned for sufficient reserves in MISO South to cover its worst single contingency in the MISO South portion of its footprint. It is this latter "worst single contingency" that the report will discuss and refer to as the MISO South WSC.

to maintain voltages within limits and shed additional firm load to maintain system balance and restore reserves for the MISO South region. MISO South's load peaked at 31,852 MW on January 17. At one point on January 17, MISO South had as much as 17,000 MW of generation unavailable, including 13,000 MW of it unplanned.[17]

MISO was not the only RC that lost generation in the Event Area. Going into Wednesday January 17, SPP, TVA RC and SeRC had 8,300 MW, 5,000 MW, and 1,400 MW of generation unavailable, respectively. The entire Event Area had as much as 33,500 MW of total unavailable generation (including planned outages) at one point on January 17, out of approximately 118,000 MW of capacity in the Event Area, and over 30,000 MW unavailable by the start of the morning peak load timeframe.[18]

The majority of the problems experienced by the many generators that experienced outages, derates, or failures to start during the Event were attributable, either directly or indirectly, to the cold weather itself. For the entire Event Area, from January 15 to January 19, Generator Owner/Operators (GO/GOPs) directly attributed 14 percent of the generator failures to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. Another 30 percent were indirectly attributable to the weather, occasioned by natural gas curtailments to gas-fired generators (16%) and mechanical causes known to be related to cold weather (14%).[19] The Team found that total outages from January 15 to 19 increased as temperatures decreased, with correlation coefficients of between -0.5 to -0.7, depending on the city. More than one-third of the GO/GOPs that lost generation during the Event did not have a winterization plan. Given the relationship between the cold and generator outages, the wealth of prior voluntary recommendations for generators to prepare for winter weather,[20] and that 70% of the unplanned outages occurred in gas-fired units, with 16% of those outages were directly attributed to gas supply issues, the Team recommends a three-pronged approach to address generator

[17] Substantial percentages of the MISO South generation fleet were unavailable in Louisiana (57.1%), Arkansas (23.5%), and Mississippi (16.8%).

[18] See Figure 22, Total Unavailable Generation. Peak non-coincident system loads for January 17 in the four BA footprints combined was 222,924 MW. See Figure 18, January 17, 2018 Peak Loads for Relevant Entities. The peak load figures cover the entire MISO, SPP, TVA and SeRC, footprints, whereas the capacity figure of 118,000 is an estimate of generating capacity just within the Event Area.

[19] All percentages in this and the preceding sentence are based on number of units.

[20] See discussion in Recommendation 1, in Section VIII below.

reliability during extreme cold weather. This approach includes NERC developing one or more mandatory Reliability Standards that require Generator Owner/Operators to prepare for the winter and to provide information regarding their preparations (or lack thereof) to their RCs and Balancing Authorities (BAs), as well as enhanced outreach to the GO/GOPs, and market incentives for those GO/GOPs in organized markets.

In addition to the primary cause of the Event, which was the significant unplanned loss of generators in the Event Area that correlated with the drop in ambient temperatures, several other factors contributed to the BES conditions faced by system operators, including:

- increased customer electricity demand across the Event Area due to extreme low temperatures;
- large power transfers:
  - MISO's Regional Directional Transfer (RDT)[21] from MISO Midwest to MISO South, which exceeded its contractual firm and non-firm limit (Regional Directional Transfer Limit (RDTL)) of 3,000 MW to provide replacement for MISO's generation outages and derates in MISO South; but also
  - remote generation power transfers, including MISO's and SPP's dispatch of wind generation output from distant locations; and
  - transfers between SPP and the ERCOT Interconnection via SPP's High Voltage Direct Current (HVDC) ties.

On January 17, MISO relied on its contractually-available transmission capacity under the RDT to schedule power to flow from generation in MISO Midwest into MISO South, to help cover the record winter electrical demand plus reserves. The RDT flow steadily increased in a north-to-south direction affecting the BES transmission system footprints of MISO, SPP, RC and SeRC, and it exceeded MISO's 3,000 MW RDTL during the early morning hours of January 17, reaching a maximum of 4,331 MW, as measured in real time, around 6:30 am CST. Although MISO exceeded the RDTL, and did not reduce the RDT below the 3,000 MW limit within 30 minutes as contemplated by the settlement agreement, MISO operators communicated with adjacent RCs (which are parties to the settlement agreement that established the RDT) that MISO would be exceeding the limit, and that if MISO's RDT flows caused a system emergency for the adjacent RCs, MISO would take appropriate actions. While the adjacent RCs did not determine that their systems were in an emergency state during the Event, they were made aware of the continuing generation outages and derates in MISO South, of MISO's

[21] See section II.B and Figure 32 for background on MISO's RDT.

Energy Emergency declaration, and of MISO's likely need to perform firm load shed if its next-worst contingency occurred.

Before the morning of January 17, none of the RCs had anticipated the multiple-wide-area[22] constrained transmission conditions that simultaneously occurred in the SPP, TVA, SeRC, and MISO South RC footprints. The Team recommends seasonal studies that consider more-severe conditions, modeling same-direction simultaneous transfers and other stressed but realistic conditions, and sharing the results with operations staff to aid in planning for more extreme days like January 17. These widespread constrained conditions caused reserves to be stranded from MISO South.[23] The Team also recommends that RCs consider deliverability of reserves, and that MISO notify the other RCs when it is counting on the as-available, non-firm portion of the RDT to meet its reserves for MISO South, so that the RCs can timely communicate if conditions on the other RCs' systems are projected to limit MISO's ability to rely on the RDT.

The RCs also did not expect the numerous mitigation measures they would need to take to maintain BES reliability on January 17, including Transmission Loading Relief, transmission reconfiguration, and the need to be prepared to shed firm load in the event of an outage of the MISO South WSC of 1,163 MW. Had this outage occurred, during the morning peak hour on January 17, MISO would have likely had to order firm load shed in MISO South for two reasons. First, MISO would not have had sufficient deliverable reserves to cover its MISO South region peak load, and second, it concurrently would have likely needed to shed firm load to alleviate low voltages at many locations that were calculated to be significantly below their limits. Normally, voltage stability is a greater risk during summer than winter, however, there can be an increased risk of voltage stability under extreme cold winter weather conditions, heavy imports, and facility outage conditions.[24] Although the system remained stable on

[22] The "wide area" each RC is responsible for includes its "entire RC Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits." (See NERC Glossary of Terms). The January 17 event involved critical flows experienced concurrently in four RC areas.

[23] By "stranded," the Team means reserves that cannot be delivered due to transmission constraints which cannot be alleviated.

[24] It has been studied that under high loads and heavy imports in a different winter-peaking area of the U.S., credible single and multiple contingencies could result in widespread post-contingency steady state voltage instability. The entity has identified these conditions as an Interconnection Reliability Operating Limit (IROL). In this

January 17, the Team recommends that MISO and other RCs perform voltage stability analysis when under similarly constrained conditions, benchmark planning and operations models against actual events which strained the system, perform periodic impact studies to identify which elements in the adjacent RCs' systems have the most impact on their own systems, and perform drills with entities involved in load shedding to prepare to execute load-shedding for maintaining reserves while at the same time alleviating severe transmission conditions.

Actions by operators to address real-time issues were effective and timely. The RC operators for SPP, MISO, TVA, and SeRC had situational awareness, communicating and coordinating their analyses and discussing mitigation actions necessary to maintain BES reliability, up to shedding firm load. RC operators also communicated as necessary with the Transmission Operators to verify that System Operating Limits (SOLs) took into account the extreme cold temperatures. Because some SOLs which operated as constraints on January 17 were based on summer temperatures or on static, year-round ratings, the Team recommends that SOLs and their associated equipment ratings be based on, at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively.

System conditions began to gradually improve after the morning peak ended at 8 a.m. CST and as the cold weather moved out of the Event Area. Warmer temperatures resulted in some generators returning to service, and decreased system loads. While MISO still sought emergency power for the evening peak on January 17, wide-area BES conditions were not as constrained as they were approaching the morning peak.

The affected RCs performed a post-Event analysis. Among the areas they identified for improvement was the joint Regional Transfer Operations Procedure (RTOP) used to govern MISO's use of the RDT, which was in effect at the time of the Event. The improvements they made to the RTOP, along with the Team's additional recommendations to add specificity and clarity during emergency situations, underscore the need for clear operating procedures for the system operators, to address similar multiple-wide-area constrained transmission conditions. The Team's recommended changes to the RTOP would clarify roles and timing, require affected entities to declare an emergency before MISO sheds firm load to reduce the RDT, and implement studies to

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instance, voltage stability analysis (VSA) is conducted daily for the next operating day to determine if the limit can be increased or decreased depending on system conditions (i.e., load, power flows, internal generation in the area, outages, etc.). The IROL is also monitored in real time using VSA to perform real-time calculations for the IROL limit based on real-time conditions.

be performed before temporarily changing the RDTL or making emergency energy purchases.

In addition to the Team's recommendations, the report discusses sound practices followed by the entities involved in the Event, and reaffirms recommendations from the 2011 Report..[25]

II. Background

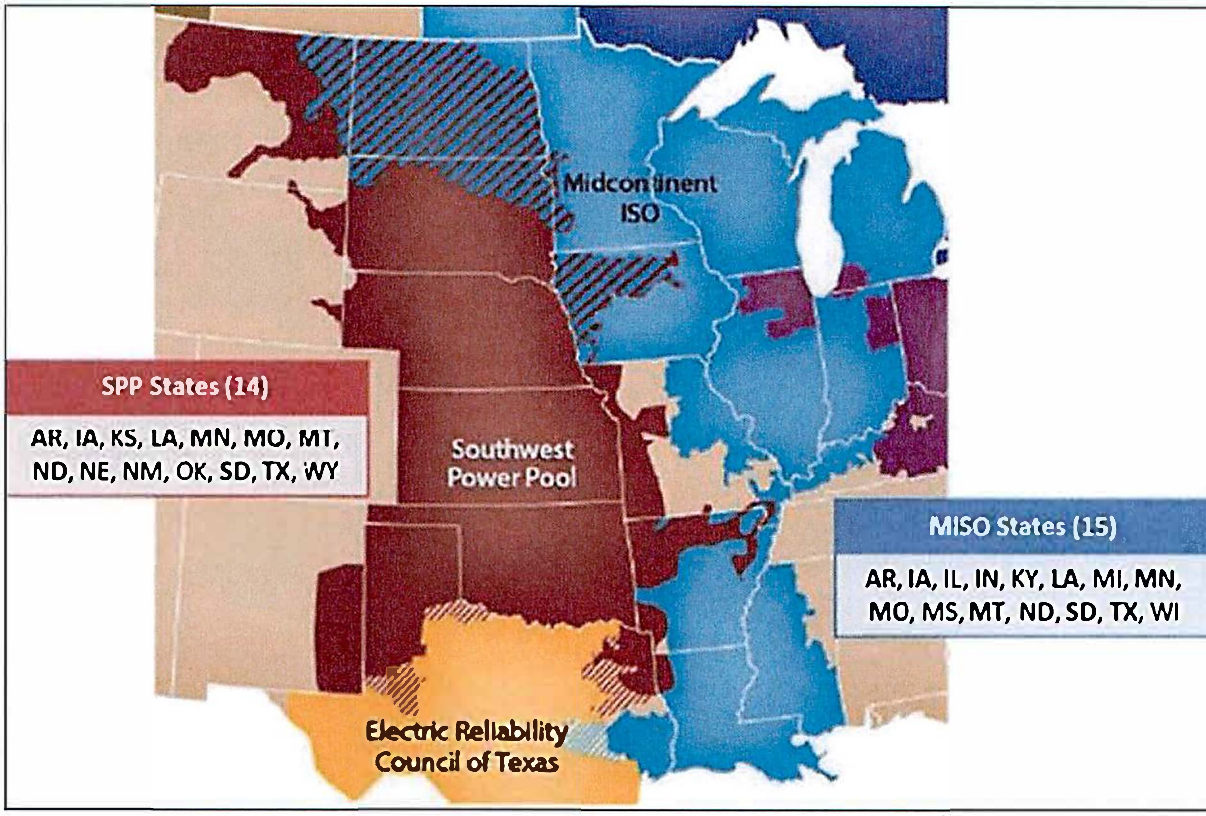
A. Affected System Overview

The Event Area is located within the Eastern Interconnection (which stretches from the East Coast to the Rocky Mountains, omitting the majority of Texas), and from eastern Canada to the Gulf Coast. Of the 15 NERC-approved RCs in North America which are responsible for having the wide-area view to oversee grid reliability, four were responsible for the reliable operations of the BES in the Event Area: MISO, SPP, TVA and SeRC.

The extra-high voltage (EHV) (345 kilovolts (kV) and above) portion of the Event Area comprises 500 kV transmission facilities spanning Arkansas, western Tennessee, Mississippi, Louisiana and Alabama. These 500 kV facilities are connected to the north and west within the Event Area via transformers to 345 kV transmission facilities located in lower Missouri and Kansas, and which run through Oklahoma and along the eastern border of Texas. There are two asynchronous HVDC connections between these 345 kV transmission facilities and ERCOT (to the west, in Texas), which operates as a functionally separate interconnection. These two HVDC ties to ERCOT (the North DC Intertie, and the East DC Intertie) allow power exchanges with the Eastern Interconnection through SPP. SPP also has several DC ties with the Western Interconnection. Other high-voltage BES transmission facilities within the Event Area include 230 kV, 161 kV, 138 kV and 115 kV facilities.

[25] See Appendix G, "2011 Recommendations on Preparation for Cold-Weather Events."

Figure 2: **MISO and SPP Regional Transmission Organization Footprints**

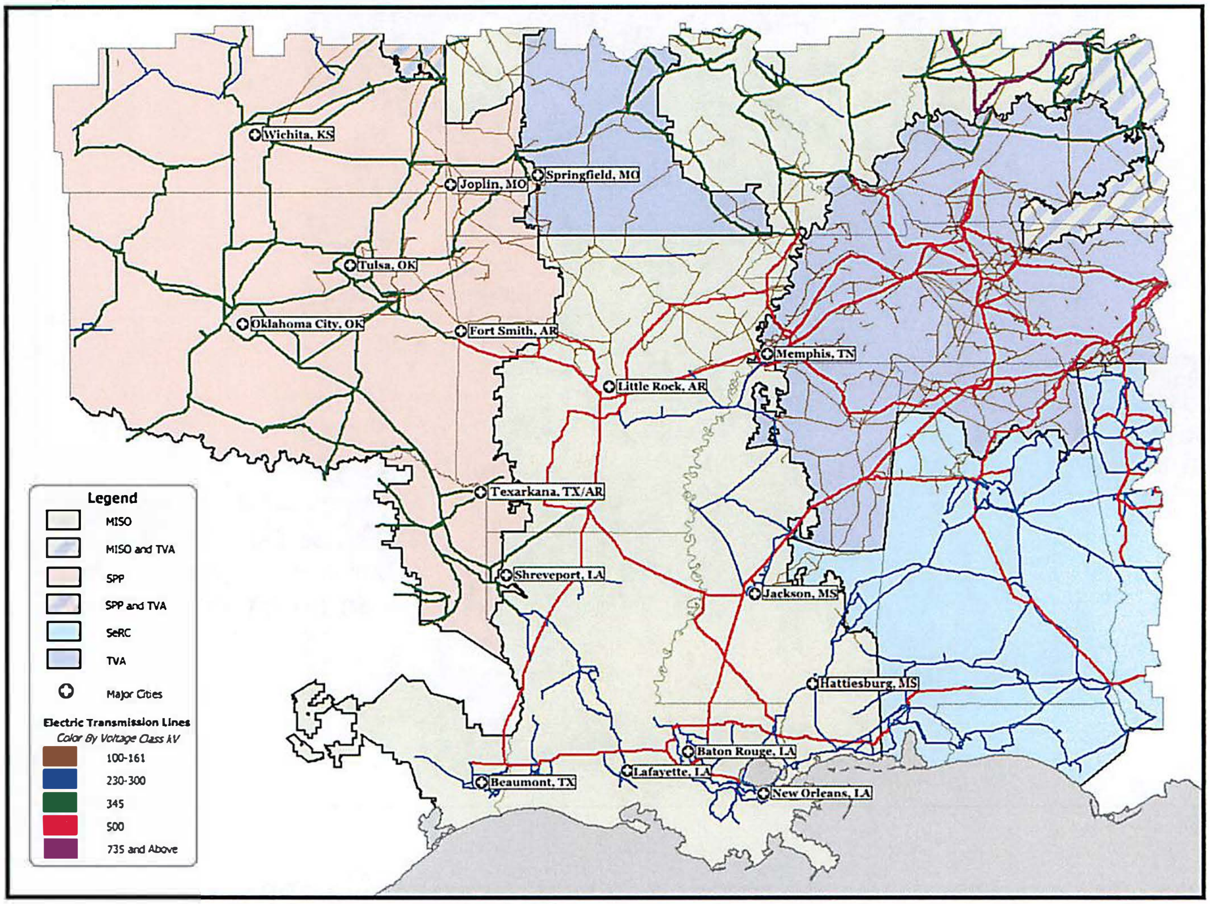


As the table below illustrates, the BES system between MISO and SPP is far more extensive than the limited number of ties between MISO Midwest and MISO South:

Figure 3: **Tie Lines Between MISO and SPP RC Versus Within MISO**

Voltage Level (kV)	Number of Tie-lines between MISO and SPP	Number of transmission lines between MISO Midwest and MISO South
69	85	0
115	30	0
138	5	0
161	41	0
230	13	0
345	16	0
500	3	1
Total	193	1

Figure 4: **Electric Transmission Lines and Cities Within the Event Area**



Transmission facilities within the Event Area serve load centers such as:

Oklahoma City, OK	Tulsa, OK	Joplin, MO	Springfield, MO
Ft. Smith, AR	Little Rock, AR	Memphis, TN	Texarkana, TX/AR
Shreveport, LA	Lafayette, LA	Jackson, MS	Hattiesburg, MS
Baton Rouge, LA	Beaumont, TX	New Orleans, LA	Wichita, KS

These BES transmission facilities also span many rural locations, serving thousands of smaller cities and towns, as well as large commercial, agricultural, and industrial loads located across portions of the south central U.S. This region of the country is normally not generation-capacity-limited. Under normal conditions MISO South has a substantial surplus of capacity, often leading to transmission flows in a southern-to-northern direction. This was not the case on January 17, 2018, due to the extensive generation outages experienced.

B. MISO Regional Directional Transfer and Related Agreements

MISO and SPP Regional Transmission Organizations (RTOs) share a border, or seam, and are parties to a Joint Operating Agreement designed to address power flows and improve operations along that seam. On December 19, 2013, MISO expanded its footprint by integrating the Entergy Operating Companies, among others, as transmission owning members (they now comprise the MISO South region). Since that date, MISO has two regions within its BA area, joined by a single firm transmission path: MISO Midwest, and MISO South. The addition of MISO South extended the seam between MISO and SPP to its current length: from the Canadian border in the north to the Gulf of Mexico in the South.

At the time the Entergy Operating Companies considered joining MISO, a dispute arose between MISO and SPP about interpreting provisions in the MISO-SPP Joint Operating Agreement about whether and/or how the two would share available transmission capacity on their respective transmission systems, particularly as to the amount of power flow, known under the Agreement as Regional Directional Transfer, or RDT, which MISO could use for intra-market flows between MISO Midwest and MISO South. The dispute was the subject of numerous filings and proceedings before the Commission and included parties in addition to MISO and SPP that were also affected by operations of the expanded MISO footprint.[26] The parties resolved the dispute by entering into a Settlement Agreement, which the Commission accepted on January 21, 2016.[27] Under the Settlement Agreement, MISO agreed to a Regional Directional Transfer Limit, or RDTL,[28] which limits MISO's north-to-south intra-market flows to 3,000 MW (1,000 MW being firm and 2,000 MW being non-firm, as-available) and

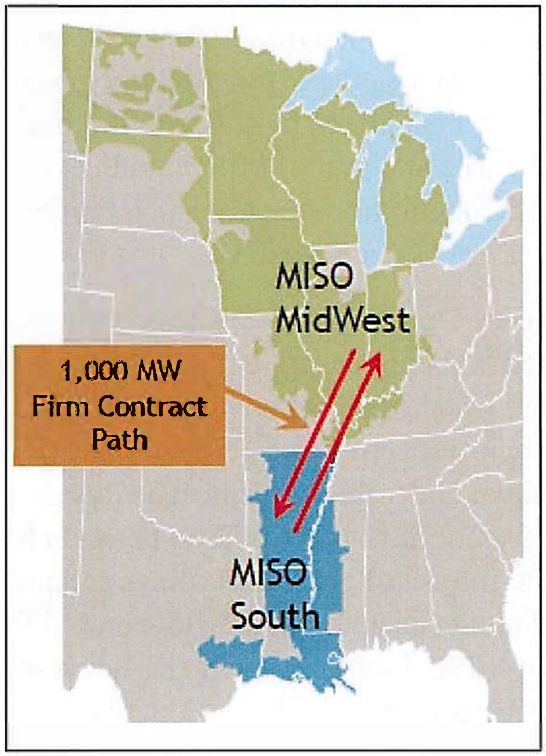
[26] *See, e.g.*, Sw. Power Pool, Inc., 146 FERC ¶ 61,231 (2014) (consolidating the proceedings in Docket Nos. EL11-34-002, EL14-21-000, EL14-30-000, and ER14-1174-000, and establishing hearing and settlement judge procedures).

[27] Sw. Power Pool, Inc., 154 FERC ¶ 61,021 (2016). The parties to the Settlement Agreement are SPP, MISO, AECI, Southern Company, TVA, LG&E/KU, PowerSouth, and NRG Energy, Inc.

[28] The Settlement Agreement between MISO and SPP refers to the flows between MISO Midwest and MISO South as Regional Directional Transfer ("RDT"). On the other hand, within MISO, the RDT-related constraint on flows is referred to as Sub-Regional Power Balance Constraint (SRPBC). In either case, the limit is contractual in nature, and is not an actual physical transmission constraint.

2,500 MW flowing south-to-north from MISO South (1,000 MW being firm and 1,500 MW being non-firm, as-available).

Figure 5: **MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT)**



Section 7.2.1 of the Settlement Agreement provided that the RDTL may be temporarily increased or decreased to avoid a transmission system emergency or during such an emergency, as long as the increased flow does not cause an emergency on the system of another party to the Settlement Agreement. Any party requesting an RDTL increase or decrease must contact the affected RCs and notify all other RCs via a posting to the Reliability Coordinator Information System (RCIS). The affected RC must assess the effects of an RDTL increase or decrease, and then notify the requesting RC whether it can accommodate such a change.

To implement the Settlement Agreement in real-time operations, the parties have a joint Regional Transfer Operations Procedure (RTOP), which addresses actions to be taken when the RDT is exceeded, requests to raise or lower the RDTL, congestion management, the effect of system emergencies and a procedure for conducting post-event reviews of events.

III. Review of Entities' Preparations for Winter 2017/2018

BES operations for any season begin well in advance, with planning and preparation based on certain historical data and assumptions. As real-time operations approach, this planning is refined with ever-more-accurate information. The Team reviewed how the relevant entities (RTOs, RCs, BAs and GO/GOPs) planned for the upcoming winter 2017/2018 season, and how those preparations assisted in, or could be improved for, ensuring reliable BES operations during the Event. The Team reviewed the relevant entities' 2017/2018 winter season:

- forecast peak loads,
- resource (generation) adequacy,
- transmission assessments, and
- generation winterization plans.

As part of its review, the Team asked the entities if they had considered relevant recommendations from similar events in their winter 2017/2018 planning.

A. Entities' Preparations for Winter 2017-2018 Operations

1. Projected Resource Adequacy for Winter 2017-2018

Historically, MISO and SPP are summer-peaking entities, TVA's BA has summer and winter peaks of similar magnitude, and SoCo BA (comprising the majority of the SeRC footprint) has more recently been a winter-peaking entity, with winter heating loads as a primary contributing factor. The table below shows the winter 2017-2018 peak forecast load, actual peak load, and actual peak load for January 17, 2018 for the entities' respective footprints.

Figure 6: **Forecast 2017/2018 Winter Peak Loads**

	MISO (Total)	MISO South Region	SPP	TVA BA	SoCo BA
Previous All-Time Winter Peak (GW)	109.3	31.1	41.5	33.4	45.9
2017/2018 50/50 Forecast Peak (GW)	103.4	28.4	41.1	31.9	41.0
2017/2018 Extreme Forecast Peak (GW)[29]	110.6	31.2	42.5	33.4	47.0
2017/2018 Actual Peak (GW) / Date	106.1 / 1/17/2018	32.1 / 1/17/2018	43.5 / 1/17/2018	32.5 / 1/18/2018	44.4 / 1/18/2018
January 17, 2018 Peak (GW)	106.1	32.1	43.5	31.6	41.6

Above 50/50 Forecast Peak/Above Extreme Forecast Peak

None of the affected RCs forecast having a shortage of generation to meet their winter peak loads. MISO, SPP, TVA BA and SeRC all provided resource adequacy projections for their entire footprints for winter 2017-2018 as part of NERC's 2017-2018 Winter Reliability Assessment, which ranged from 32% to 67% resource reserve margins (excluding planned and expected unplanned generation outages), well-above their required reserve margins of 12% to 17%.[30] The 29.6% reserve margin predicted for the MISO South region was also much higher than any of the required reserve margins.[31]

The above reserve margin values do not take into account planned or scheduled generation outages to perform maintenance, or refueling outages for nuclear generation. In portions of the south central U.S., where winter typically brings relatively mild temperatures, lower system loads, and adequate reserve margins (i.e., 30% or greater),

[29] SPP and SeRC calculated extreme scenario forecasts, while MISO and TVA used 90/10 scenarios.

[30] Data Source: NERC 2017/2018 Winter Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_11202017_%20Final.pdf

[31] The annual Weighted Equivalent Forced Outage Rate (wEFOR) for 2017 for MRO was 10.5%, and for SERC was 7.6%.

generation outages may be planned for the winter months. This allows maximum generation availability during summer, when much higher loads are experienced. MISO and SPP, both summer-peaking entities,[32] would have planned more generation outages for the winter season than the summer (as well as during the so-called "shoulder" seasons of spring and fall). While planned outages can be rescheduled at times if system operators have sufficient notice of narrowing reserve margins, eventually the outages must occur to allow required unit maintenance. For example, from September 21-25, 2017, temperatures were unseasonably high throughout the MISO footprint. High planned outage rates, typical of shoulder months, and 1,100 MW of forced outages contributed to tight system conditions, leading MISO to declare a Maximum Generation Event on September 22, 2017.[33] MISO coordinated with Generator Operators during the operations planning horizon, asking them to shift their outages if possible to another time of the year when system loads and planned generation outages were forecast to be lower than the September 2017 conditions. One of the Generator Operators agreed to shift its planned outage until January, 2018, and thus was not available during the January 17 Event.

Winter reliability assessments also do not attempt to quantify the risk of fuel supply interruptions, although the Winter 2017-2018 assessments did include the data below illustrating the capacity of generation resources by fuel type.[34]

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[32] The scheduling of significant generation outages during the winter months is less likely in other, winter-peaking areas of the country, where their typical winter temperatures are much lower - resulting in much higher system loads and therefore lower supply reserve margins.

[33] IMM Quarterly Report: Fall 2017, MISO Independent Market Monitor, Potomac Economics, available at https://www.potomaceconomics.com/wp-content/uploads/2017/12/IMM-Quarterly-Report_Fall-2017-Final.pdf.

[34] Data source for SPP and MISO: NERC Winter 2017/2018 Reliability Assessment. Data for SeRC/Southern and TVA BA was aggregated into SERC into the NERC Winter Reliability Assessment; therefore, the Team used publicly-available data for SeRC and TVA BA.

Figure 7: Generation Capacity Data by Fuel Type

	MISO		SPP		SeRC-SoCo BA		TVA BA	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Biomass	535	0.4%	39	0.1%	116	0.2%	---	---
Coal	61,452	42.7%	23,995	34.6%	16,890	36.0%	8,200	20.4%
Hydro	1,237	0.9%	4,771	6.9%	1,661	3.5%	5,149	12.8%
Natural Gas	**60,328**	**41.8%**	**33,873**	**48.8%**	**19,514**	**41.6%**	**15,371**	**38.2%**
Nuclear	12,866	8.9%	1,943	2.8%	3,680	7.8%	8,609	21.5%
Other	---	---	62	0.1%	3	0.0%	---	---
Petroleum	3,168	2.2%	1,717	2.5%	---	---	---	---
P. Storage	2,562	1.8%	482	0.7%	1,095	2.3%	1,615	4.0%
Solar	159	0.1%	197	0.3%	2,504	5.3%	1,100	2.7%
Wind	1,675	1.2%	2,247	3.2%	1,474	3.1%		

As the above table demonstrates, MISO, SPP, TVA and SeRC rely on a substantial amount of natural gas-fired generation. None of these RCs expected any gas pipeline issues for the winter 2017-2018 that would detrimentally impact electric generation availability, based on their communications with pipeline operators. For instance, MISO stated in its 2017-2018 Winter Readiness presentation[35] that lessons learned from the 2014 Polar Vortex helped it to plan for the coming winter, including monitoring of, and communications with gas pipelines; gas/electric market timeline changes; and gas usage profiles of generators. However, as discussed below in section VIII, gas pipeline issues did adversely affect electric generation during the Event.

2. Seasonal Transmission Assessments for Winter 2017-2018

MISO, SPP, and the other relevant Planning Coordinator entities generally perform seasonal transmission assessment studies several months before the winter and summer seasons, which are intended to test system performance under conditions anticipated that season, including expected transmission outages and realistic estimates of load, generation and transfers across the system. The affected entities performed their

[35] Data Source: MISO Winter Readiness Presentation, October 19, 2017.

winter 2017-2018 assessments in three separate, although somewhat coordinated, processes.

MISO: MISO performed its Coordinated Seasonal Transmission Assessment in the fall of 2017 to analyze transmission performance for north-to-south and south-to-north intra-market power transfers to determine power transfer limits for the 2017-18 Winter Peak season. MISO works with members and neighboring planning entities on the study scope, modeling and outage updates, and analysis review; the results then inform winter readiness efforts, such as MISO's annual Winter Readiness Workshop.

MISO's winter 2017-18 Coordinated Seasonal Transmission Assessment included five analyses: 1) Steady-State AC Contingency Analysis; 2) First Contingency Incremental Transfer Capacity Analysis; 3) Critical Interface Voltage Stability Analysis; 4) Wind Generation Sensitivity; and 5) Phase Angle Analysis. MISO modeled transfers by increasing generation in the study export area while reducing generation in the study import area and honoring maximum generation limits. MISO's First Contingency Incremental Transfer Capacity Analysis included transfers from MISO Midwest (MISO North and Central Regions) to MISO South, the same transfer path at issue in the Event, resulting in an inter-regional transfer capability of 4,650 MW. Since the agreed RDTL for real-time flows from MISO Midwest to MISO South Region is 3,000 MW, the study indicated that the 4,650 MW transfer capability was considered adequate for the upcoming winter season. To reach this conclusion, MISO adjusted transfers in its First Contingency Incremental Transfer Capacity analysis by increasing or decreasing generation in the desired area(s) on a sliding scale. The analysis did not model the outages of individual generators that would likely occur during actual system conditions.

MISO explained that power transfer distribution factors[36] are sensitive to, and vary substantially on, the generation dispatch modeling in the study. While the 2017-18 Coordinated Seasonal Transmission Assessment showed a winter season First Contingency Incremental Transfer Capacity of 4,650 MW, during the Event, SPP, TVA and other affected entities started experiencing constraints on their systems when MISO's Midwest to South transfers were much lower than 4,650 MW (e.g., at or below 3,000 MW).[37] MISO's First Contingency Incremental Transfer Capacity analysis was not used to inform lowering or raising of the RDTL, leaving the RDTL changes to be determined in the real-time operations horizon, without the benefit of any insights which could have been gleaned from the First Contingency Incremental Transfer Capacity Analysis. Even if the First Contingency Incremental Transfer Capacity analysis in MISO's Coordinated

[36] See Appendix D.

[37] See Section V, below.

Seasonal Transmission Assessment had indicated a lower transfer limit for a particular set of inputs (available generation, transfers, load, etc.), MISO did not use the Seasonal Transmission Assessment results to support MISO in its requests to raise or lower the RDTL for any particular days of that season.

SPP performed its winter assessment by creating two different snapshot cases for each week covering the study period of November 2017 through the end of March 2018, using Wednesday and Sunday cases to represent high-load and low-load periods for each week. SPP performed an initial contingency analysis to observe any transmission or voltage violations caused by loss of the contingency elements. To remedy any limit exceedances found in the contingency analysis, SPP applied a security constrained redispatch (SCRD) to each case as needed. The SCRD simulated iterative changes to SPP's generation dispatch in order to reduce or eliminate violations, while minimizing the creation of additional constraints. Once the redispatch was completed, a final contingency analysis was performed and any resulting violations were analyzed for further mitigations, overlapping outages that need rescheduling, or reported for further study. SPP's winter assessment revealed no expected issues and noted that extreme weather or fuel delivery issues could result in localized or brief capacity constraints, but that existing SPP congestion management procedures, documented mitigation strategies and operating guides appeared to be sufficient to manage any potential issues. SPP did not analyze intra-market transfers, such as those that might result from widespread generation outages.

TVA and SeRC participate in SERC's seasonal assessment. As a measure of projected transmission system performance for the 2017/18 winter season, the relevant study utilized assessments of incremental transfer capabilities among the SERC member systems. SERC's analysis to determine transfer capabilities was similar to MISO's in that transfers were simulated by increasing generation in an exporting area and decreasing generation in the associated importing area. However, in some instances, loads were reduced within subregions in SERC, to provide sufficient capacity to model desired levels of transfer. The studies did not identify any constraints relevant to the Event.

3. 2017-2018 Winterization Readiness Preparation

a) Reliability Coordinators and Balancing Authorities

RCs have the wide-area view of the BES (typically including multiple BAs and TOPs) and are responsible for its reliable operation, while the BAs' responsibilities within their BA footprint include integrating resource plans and maintaining generation-load balance.[38] The Team found that MISO, SPP, TVA and SeRC routinely take steps to verify that the BES Generator Owners/Operators on which they depend are prepared for winter weather and extreme cold events. To better understand the topic of generators preparing for winter in the Event Area, one must first understand common differences between generating facilities in northern areas versus those in southern or other warm weather areas.[39]

Geographic location and the corresponding ambient weather conditions, including expected temperatures and wind speed, have a direct impact on the preferred design for generating facilities. In the northern regions of the United States, most generating plants (especially steam-cycle plants) are designed and constructed with the boilers, turbines/generators, and certain ancillary equipment housed in one or more enclosed buildings. In the colder months, heat radiated from boilers, other generation equipment, and supplemental heaters maintain temperatures at a high enough level to prevent freezing. Enclosed areas are generally designed and constructed with fresh air inlets and roof-mounted exhaust ventilators for cooling purposes during the hot weather months.

Figure 8: **Enclosed Coal-fired Power Plant in the Northeastern United States**

In the southern and other warm weather regions of the U.S., generating plants are designed and constructed without enclosed building structures, with the boilers, turbine/generators, and other ancillary systems exposed to the weather, in order to

[38] NERC Glossary of Terms.

[39] The following two paragraphs, including the photographs, are drawn from the "Appendix: Power Plant Design for Ambient Weather Conditions" to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations, found at https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

avoid excessive heat build-up. For the colder months, when temperatures may fall below freezing, Generator Owners and Operators undertake specific freeze protection efforts, which typically involve a combination of heat tracing, insulation, temporary heating, and temporary wind breaks (to prevent heat loss from normal operations and from supplemental heating sources).

Figure 9: Non-Enclosed Coal-fired Power Plant in the Southern United States

Generally, the affected RCs and BAs had issued winter readiness guidelines to Generator Owners/Operators within their footprints for the winter 2017-2018 season. PowerSouth, TVA BA, and Southern Company included specific freeze protection plans for generating units, as well as other winter assessment processes, to be performed prior to the winter season, as early as October in some instances. Some of these assessment processes included identifying systems and equipment within generating plants requiring winterization; completing items on a winter preparation checklist; and engaging meteorologists to preview winter forecasts and assess risks for extreme temperatures.

Some of the RCs and BAs also checked on generating units prior to winter weather to confirm the units' winter readiness. For instance, LG&E/KU (within TVA RC) held calls with individual generating plants to verify the plants had prepared for winter. TVA BA conducted winter readiness inspections of its units. Several other entities including PowerSouth (within SeRC), which owns generating units, have winterization plans that include checking plant equipment to ensure it is properly winterized.

MISO issued surveys to its Generator Operators on fuel availability prior to the winter. Some of the surveys included guidelines from the NERC winterization checklist[40] and ERCOT's winterization process. MISO noted that prior to the 2014 polar

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[40] The NERC Winterization guidelines provide details on specific components that must be addressed in an effective winter weather readiness program, including: (I) Safety; (II) Management Roles and Expectations; (III) Processes and Procedures; (IV)

vortex event, it did not have a process for Generator Operators to report issues pertaining to winter readiness, such as fuel unavailability. However, following the 2014 event, MISO developed and implemented a process for generating units to update MISO about their readiness for the winter, including fuel availability. MISO implemented this process as part of the cold weather alert it issued prior to the January 17, 2018 event.

Most of the affected RCs and BAs educated their personnel and stakeholders on important generator winter readiness preparations through workshops in the fall of 2017. For instance, SPP and MISO held "Seasonal Preparedness" and "Winter Readiness" workshops, respectively. The workshops included discussions on high load and extreme outage scenarios, adequacy of generation resources to meet demand, and weather forecasts for the upcoming winter season. Southern Company, PowerSouth (in SeRC) and LG&E/KU (in TVA RC), which also own generating units, reported that they trained their operators to address freezing weather hazards to personnel and equipment. These entities also held post-winter meetings to review successes and setbacks from the previous winter season and get a head start on preparing for the next winter season.

RCs and BAs also prepared for winter by anticipating potential fuel supply issues. At least two large interstate pipelines in the affected regions declared force majeure[41] during the Cold Weather Event, and at least one intrastate pipeline in the affected regions issued a critical notice for its entire pipeline group warning of imminent extreme cold temperatures, which increase demand for gas used by generators as well as to heat homes and businesses. Some generating units in the affected RC areas reported that they did not have firm gas supply or transportation contracts for their generating units. However, Southern Company (in SeRC), with fuel tank storage at its generating facilities, was able to re-supply generating units in the Event Area when their main fuel supplies were interrupted as a result of gas pipeline issues. Gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 generating units, totaling approximately 2,200 MW, during January 15 to 19 in the Event Area.

Evaluation of Potential Problem Areas; (V) Testing; (VI) Training; and (VII) Communications.

[41] Force majeure clauses allow parties to excuse non-performance under a contract when some unavoidable event occurs (such as a hurricane). In the gas pipeline context, declaring force majeure can excuse a pipeline which fails to deliver to shippers which had firm transportation contracts. It can also potentially excuse a gas seller's failure to deliver.

When fuel supplies are interrupted, dual-fuel[42] units can help to protect reliability, but only if the unit can successfully switch to its backup fuel. From January 15 to 19, 2018, 40 out of 55 units operated by Southern Company (in SeRC) successfully switched to their secondary fuel sources and provided needed energy supply. Four of the seven BAs had procedures in place to test dual-fuel generating units prior to the 2017-2018 winter season, and TVA BA tests its dual-fuel units routinely during operations. For instance, LGE/KU (in TVA RC footprint) requires twice-yearly tests of dual-fuel units, whereas SeRC entities conducted annual tests to confirm that dual-fuel generating units can successfully switch to their alternate fuels. MISO noted that it does not currently have a program to ensure that generating units can switch fuels, however it would accommodate GO/GOPs that wish to test their fuel switching capabilities. SPP does not currently conduct any tests to confirm the fuel-switching capability of generating units within its service area.

Load Modifying Resources (LMR), and Demand Side Management (DSM) are tools used during capacity shortages to help maintain the energy balance. Entities took varying approaches to ensuring that these resources would be able to perform when needed. For instance, MISO implemented its LMR operational capabilities during the Event, even though those resources were not required to perform in the winter..[43] Other RCs reported that no penalties are assessed if their LMR is unavailable due to planned maintenance or force majeure.

b) Generator Owner/Operators

Twenty-one Generator Owner/Operator entities, many of which owned and/or operated multiple generating units, provided data regarding outages that occurred between January 15 and 19, 2018. Of those 21, **more than a third**[44] did not have winterization procedures at the time of the Event. Those that did have plans to prepare for the winter included one or more of the following elements:

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[42] Some generators have dual-fuel capability – that is, they allow for a unit to switch from its primary source of fuel (e.g., natural gas) to a secondary source of fuel (e.g., oil or coal) if needed. Fuel switching is one method that generators can use to alleviate the strain when a particular fuel source is in short supply. It can also be useful when seeking cheaper alternatives for fuel.

[43] Unless the resource had bid in and was dispatched in real time.

[44] Eight out of 21.

- freeze protection measures (discussed in more detail below);
- enhanced staffing measures, which could include the addition of a "freeze protection operator," responsible for inspecting critical equipment, ensuring appropriate protections are in place, and the addition of more staff during severe weather; and
- fuel supply and dual-fuel capability: These procedures include checking fuel tank levels at least every other day during seasonal cold weather to ensure sufficient fuel during a cold weather event, and pre-freeze test firing of dual-fuel units that have not fired on their secondary fuel source during the previous year.

The ambient temperature design rating of a generating unit is an important aspect of preparing for winter weather and severe cold weather events, because it specifies the temperature(s) at which the unit's full output can be achieved. Most of the units in the Event Area for which the ambient temperature design rating is known were rated between -10 and 10 degrees Fahrenheit,[45] with some exceptions. A handful of units had ambient temperature design ratings to -20 degrees, and four units were rated for use to -40 degrees. Some entities did not know their units' ambient temperature design ratings, or did not incorporate those ratings into their freeze protection measures.

Several affected entities did account for their units' ambient temperature design ratings in their operating procedures. For example, one entity set minimum freeze protection temperatures for each plant site, with specific guidance for physical assessment of existing critical freeze protection systems and the development of action plans if those systems do not meet the ambient temperature minimums.

Among the freeze protection measures contained in winterization plans were the following steps:

- Checking and maintaining adequate inventories of all commodities, equipment, and consumables that would aid in severe winter weather.
- Insulating exposed equipment and checking for missing or damaged insulation prior to cold weather.
- Checking heat tracing on all critical lines and piping to ensure that the circuits remain functional. Temperature guns can be used to check that heat tracing is working correctly.
- Closing doors on boiler enclosures to prevent cold air from entering.
- Confirming fuel heaters are in service and working properly prior to cold weather.

[45] All temperature references in this report will be to degrees Fahrenheit.

- Considering pre-warming scheduled units prior to a forecast cold weather event.
- Checking that all critical site-specific problem areas have adequate protection to ensure operability, and emphasizing the points in the plant where equipment freezing could cause a unit trip, derate or failure to start.
- Placing thermometers in areas containing equipment sensitive to extreme cold conditions and in freeze protection enclosures, ensuring that temperatures are monitored and maintained above freezing.
- Evaluating plant electrical circuits for adequate load capacity and ensuring that Ground Fault Circuit Interrupters are used properly.
- Reviewing work management systems for open corrective maintenance work orders that could affect the operation and reliability of the generating unit in cold weather, and ensuring that the work orders are prioritized correctly so that the work is completed prior to the winter season.
- Ensuring that all modifications and construction activities are performed such that the changes maintain cold weather readiness for the generating unit. (i.e., the changes do not degrade the generating unit's ability to withstand cold weather—for example, tearing pipe insulation).
- Disconnecting sensing lines on pressure transmitters to prevent freezing of these lines.
- Installing wind barriers, such as tarps or semi-permanent barriers constructed of wood or metal, to protect critical instruments, sensing lines, controllers and piping.
- Cleaning coal feed chutes as needed to keep coal supply flowing.
- Closing all building doors to prevent cold air from entering.
- Monitoring and removal of ice and snow.

Proper training of operators on winterization is critical to ensure they will be prepared to take the necessary actions before and during extreme cold weather events. Many of the affected entities employ preventative cold weather training, such as an annual review of site-specific winterization procedure for all operators, or requiring initial and recurring operator certification on procedures which include winterization plan procedures. Less experienced operators may be asked to perform a cold weather checklist with experienced operators.

With a few exceptions, the majority of the GO/GOPs that had winterization plans also conduct "lessons learned" following major weather events, including severe cold weather events. In these evaluations, the entities review their performance during the severe weather, determine root causes of any weather-related problems, and develop additional best practices for future similar events. In many cases, the entities incorporate the takeaways from those evaluations in their written guidance on winter weatherization procedures. Some entities consider best practices from neighboring generation or industry partners in keeping their winterization processes comprehensive and up-to-date. Some entities provided specific examples of differences between their current winterization procedures and previous ones as a result of lessons learned. Several of these are worth highlighting, such as the required "freeze protection" training for new hires and annual "refresher" trainings for appropriate personnel, and the addition of materials for extended stays of personnel in severe cold weather events (e.g., cots, food, camp stoves).

IV. Near-Term Forecasts and Preparations for the Week of January 15

A. Short Range Weather and Load Forecasts

1. Impending Weather Conditions

In general, average temperatures remained at or above-freezing for the deep south into Monday January 15; however, as arctic high pressure moved from the northern plains to the central and eastern U.S. on January 15-17,[46] it resulted in average temperatures well below freezing for areas including parts of the plains, the Mississippi Valley, and Tennessee.[47] This cold front was forecast several days in advance. On Friday, January 12, at 3 p.m., the National Weather Service issued its "US Hazards Outlook" covering the period that included January 15 to 19.[48] It predicted that an "arctic air mass" would reach the eastern half of the U.S. by January 17 and "last for several days," bringing "much below normal temperatures," with "maximum and minimum temperatures 12 -28 degrees [Fahrenheit] below normal."

2. Mid- and Short-Term Load Forecasts

MISO generates Mid-Term Load Forecasts and Short-Term Load Forecasts within the operating horizon (next four-six days prior to the operating day). MISO's Mid-Term

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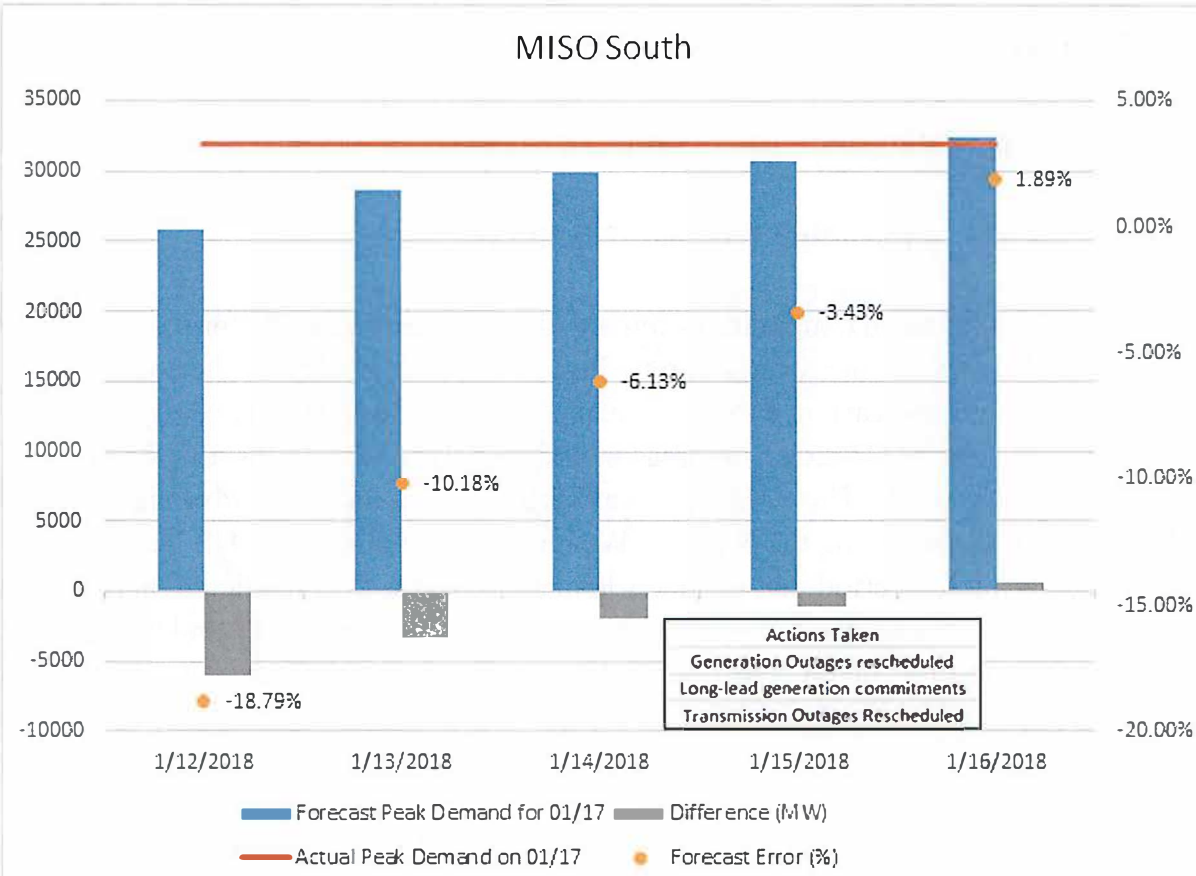
[46] Source: US HAZARDS OUTLOOK 300 PM EST JANUARY 10 2018, NWS Climate Prediction Center (http://www.cpc.ncep.noaa.gov/products/archives/hazards/data/2018/KWNCPMDTHR.20180110).

[47] https://www.timeanddate.com/weather/usa, based on NOAA historical weather observations.

[48] http://www.cpc.ncep.noaa.gov/products/archives/hazards/data/2018/KWNCPMDTHR.20180112 s

Load Forecasts were the primary load forecasts used as an input to its operational planning to make longer-lead-time resource commitment decisions. The table below compares load forecasts generated on January 12, 13, 14, 15 and 16 for January 17, 2018 for MISO South.

Figure 10: MISO's Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of January 17, 2018



MISO's five-day, four-day and three-day-ahead "mid-term" peak load forecast errors in forecasting the actual MISO South peak load for January 17, 2018 were larger (approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW lower than actual peak load, respectively) than forecast error rates for the same period for the other RCs involved in the event. SPP's, TVA's BA, and SeRC's (SoCo BA) load forecasts comparable to this timeframe were much more accurate (with error rates ranging from 5.6% lower to 3.0% higher than actual peak load for five-days-out, 4.6% lower to 4.8% higher than actual for four-days-out, and 2.8% lower to 4.0% higher than actual for three-days-out). Improved Mid-Term Load Forecast accuracy could have helped MISO plan for additional longer-lead-time actions to be better prepared for the operating day of January 17, 2018. MISO provided the high and low temperature forecasts for January 17 from January 12, 13, 14, and 15, which it incorporated into its load forecasts for January 17, as shown below:

Figure 11: MISO's High and Low Temperature Forecasts Used in MISO South Load Forecasts: 5-day, 4-day, 3-day, 2-day, 1-day ahead of January 17, 2018

City Name, State	1/12/18 for 1/17/18	1/13/18 for 1/17/18	1/14/18 for 1/17/18	1/15/18 for 1/17/18	Actual for 1/17/18
Little Rock, AR	33/19	30/15	28/12	32/12	29/9
Jackson, MS	41/21	35/16	32/14	33/15	31/10
Baton Rouge, LA	47/31	41/24	40/22	39/20	37/12
New Orleans, LA	51/34	42/27	41/25	38/24	36/19

The forecast temperatures MISO used in its MISO South load forecasts for January 17 on January 12 (five days ahead) were considerably higher than the actual highs and lows on January 17. The five-day-ahead forecast was in the normal range for mid-January, and was therefore not effective in providing a warning for the severity of the upcoming cold snap. The forecasts improved somewhat, but even the forecasts for January 15 (two days ahead) were 3 to 8 degrees higher than the minimum temperature observed on January 17.

B. Generation Unavailable for the Entire Event

Planned generator outages are typically scheduled months or even years in advance, to perform necessary maintenance, or in the case of nuclear power plants, refueling. While Reliability Coordinators like MISO can ask Generator Owners/Operators to reschedule their planned generation outages for system reliability, they cannot require the Generator Owners/Operators to do so. At some point, the maintenance or refueling must be accomplished, and there are only so many opportunities to schedule outages so as to avoid peak system conditions and ensure sufficient generation remains available.

MISO South's planned generation outages totaled 4,049 MW for the week of January 15, 2018, which included three generators larger than 500 MW and one over 1,000 MW. MISO was able to reschedule 1,700 MW of generation outages during the week of January 15, which would otherwise have added to the 4,049 MW. In addition to the planned generation outages, MISO South experienced a number of forced generation outages and derates, as shown in the table below. SPP RC, TVA RC, and SeRC's planned and unplanned outages within the Event Area from January 15 to the start of January 17 are also shown in the table below.

Figure 12: **Event Area Approximate Planned and Unplanned Generation Outages, at the Start of January 15, and January 17, 2018**

	Planned, at the start of:		Unplanned, at the start of:		Total Unavailable, at the start of:		Event Area Approx. Capacity
	Jan. 15	Jan. 17	Jan. 15	Jan. 17	Jan. 15	Jan. 17	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
MISO South	4,000	4000	5,700	7,600	**9,700**	**11,600**	**41,800**
SeRC	700	700	300	700	**1,000**	**1,400**	**24,400**
SPP	2,300	2,300	2,500	6,000	**4,800**	**8,300**	**34,500**
TVA RC	100	100	2,100	4,900	**2,200**	**5,000**	**17,400**
TOTAL	**7,100**	**7,100**	**10,600**	**19,200**	**17,700**	**26,300**	**118,100**

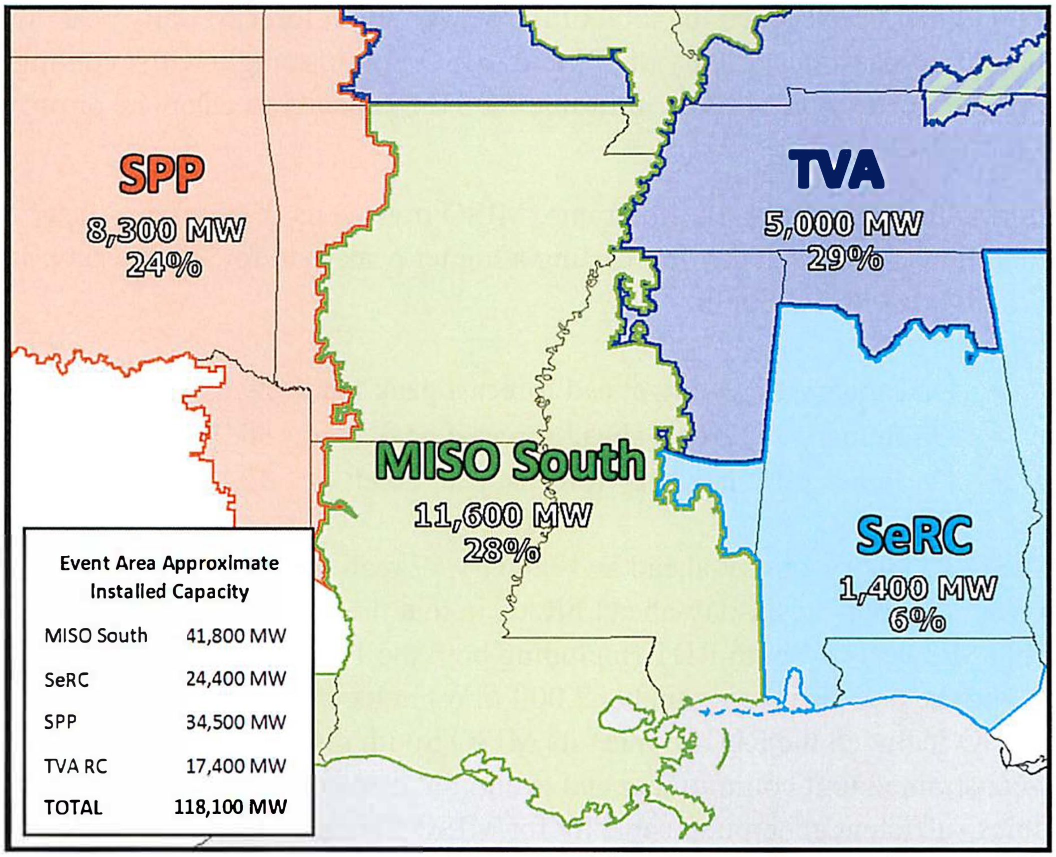
At the start of the week of January 15, MISO forecast the following conditions for its MISO South region:

Figure 13: **MISO South Region Forecast Peak Load for January 17, 2018 and Available Generation, at the Start of January 15, 2018**

	Approx. Capacity	Total Unavailable Generation	Available Generation	January 17, 2018 Forecast Peak Load
	(MW)	(MW)	(MW)	(MW)
MISO South	41,800	9,700	**32,100**	**30,761**

By the start of January 17, 2018, planned generation outages within the MISO South, SPP, TVA RC, and SeRC portions of the Event Area totaled approximately 7,100 MW, and forced generation outages and derates totaled approximately 19,200 MW, for a total of 26,300 MW, or approximately 22%, out of a total Event Area estimated generation capacity of approximately 118,000 MW.[49] By the start of January 17, outages and derates in MISO South reached 28% of its capacity, and SPP's southern footprint within the Event Area reached 24%. The areas in which generation outages and derates occurred by the start of January 17, and the Event Area generation capacity statistics for each RC, are shown below.

Figure 14: Total Generation Outages and Derates Within the Event Area, Beginning January 17, by RC Footprint



Event Area Approximate Installed Capacity	
MISO South	41,800 MW
SeRC	24,400 MW
SPP	34,500 MW
TVA RC	17,400 MW
TOTAL	**118,100 MW**

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[49] This total includes forced outaged and derated generation, with some that occurred prior to the week of January 15, as well as on January 15-16. The Event Area did not include the entire footprints of MISO, SeRC, SPP, and TVA. The Event Area generation capacity numbers cited are only a portion of the total generation capacity of MISO, SeRC, SPP, and TVA. The remaining areas of the MISO, SeRC, SPP, and TVA RC footprints were not affected by the Event.

C. Changes/Adjustments Made by RCs Due to Impending Conditions Forecast

1. Pre-real-time Resource Commitment Process

For the week of January 15, MISO performed a "forward reliability assessment commitment" (FRAC) in advance of the January 17 operating day. FRACs occur four- to six-days-ahead of the operating day, and commit longer-lead generation (i.e., units that require 20 hours or more advance notice to come online). MISO's FRAC projected for January 17 took into account available generation capacity located in MISO South, external interchange imports and exports scheduled for the MISO South region. MISO committed these resources on an hourly basis so that the total (generation capacity and net exchange) met or exceeded the total of the MISO South forecast daily peak loads, plus peak load forecast uncertainty of 5% and MISO South's single worst contingency.[50] The FRAC did not rely on MISO's intra-market RDT capacity to calculate or provide reserves for MISO South.

- During the January 14-16 timeframe, MISO revised its forecast peak load conditions, with each day forecasting a higher peak load for Wednesday, January 17, 2018 for MISO South:
  - On January 14, 3-day-ahead forecast peak load: 29,899 MW
  - On January 15, 2-day-ahead forecast peak load: 30,761 MW
  - On January 16, next-day forecast peak load: 32,455 MW

MISO's January 16 day-ahead and January 17 real-time unit commitments differed from the four- to six-day-ahead FRAC in that they relied upon the entire 3,000 MW MISO Midwest-to-South RDT (including both the 1,000 MW firm transmission capacity, and the non-firm, as-available 2,000 MW) in its calculation of reserves. Even though MISO included the RDT to meet its MISO South reserves for the next day, in its security-constrained unit commitment and economic dispatch, MISO normally commits or schedules sufficient generation capacity for MISO South, so that the RDT is generally held at a "zero" transfer level between MISO Midwest and MISO South.[51]

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[50] Normally MISO South's single worst contingency was 1,415 MW, but that unit was on forced outage, leaving the 1,163 MW unit as the single worst contingency for MISO South FRAC calculations for January 17.

[51] MISO's Enhanced Reserves Procurement Process filing, accepted by the Commission in August of 2018, reflected that MISO intends to rely upon the full 3,000

As of January 16, with a higher forecast MISO South peak load (32,455 MW) for the next day, and with MISO South available reserves now forecast to be 2,147 MW, MISO fell short of covering the next-day forecast load + MISO South single worst contingency + load forecast reserve/uncertainty, by 576 MW. The reserves shortfall would need to be in part supplied from MISO Midwest, using MISO's RDT, unless other actions were taken by MISO, such as scheduling imports directly into MISO South, via power transfers from directions other than the north-to-south RDT. MISO made the following declarations as January 17 approached and its projected reserves narrowed:

Figure 15: **Declarations Made by MISO in Preparation for January 17 and 18**

Declaration	**MISO Region**	**Issuance**	**Start Time**	**End Time**
		(CST)	(CST)	(CST)
Conservative Operations[52]	South	1/15/18 4:59	1/15/18 5:00	1/18/18 13:00
Cold Weather Alert[53]	South	1/15/18 15:00	1/16/18 5:00	1/16/18 13:00
Maximum Generation Alert[54]	South	1/16/18 21:50	1/17/18 4:00	1/17/18 11:00

MW of RDT, including the as-available, non-firm portion, in establishing reserves for MISO South. *Midcontinent Independent System Operator, Inc.*, 164 FERC ¶ 61,129 (2018).

[52] MISO's "Conservative System Operations" procedure identifies the actions resulting from this declaration. Actions include additional control center staffing and deferring or canceling maintenance or testing of BES generation and transmission equipment, and critical computer systems (e.g. energy management systems). SO-P-NOP-00-449 Rev 0 Conservative System Operations.pdf (#1981). The reasons given for the Conservative Operations declaration were record low temperatures and high loads forecast, forced generation outages and derates, as well as delayed outage returns.

[53] MISO's "Cold Weather Alert" procedure identifies the actions resulting from this declaration. Actions include communication to GOPs to implement plans to winterize units and plants to ensure availability during emergency conditions, coordinate personnel staffing to ensure all scheduled combustion turbines and diesel generators are available for loading during load pick up period, and review fuel supply/delivery schedules availability during emergency conditions. Reliability Coordinator Information System (RCIS) log.

[54] MISO attributed the Maximum Generation Alert to forced generation outages and higher than forecast load. Among other measures, the Maximum Generation Alert

SPP, TVA BA and SeRC had similar near-term processes for their generation/resource commitment, and they each predicted sufficient generation supplies across their respective footprints for the next day, January 17. In addition to meeting their respective footprint's electrical demand, as described further below in section V of the report, both TVA BA and SeRC/Southern Company were able to provide emergency energy to MISO South on January 17.

2. Next-Day Operational Planning Analysis (OPA) of Transmission Conditions (Performed on January 16, 2018 for the January 17 Operating Day)

In order to develop their Operational Planning Analyses (OPA),[55] MISO RC, SPP RC, TVA RC, and SeRC performed next-day contingency analyses, including both steady-state thermal and voltage stability analyses. The completed contingency analyses were compared against relevant limits, including SOLs and IROLs, as well as voltage limit criteria,[56] which are shown in Figure 16.

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declaration called for all available economic resources to be committed to meet load, firm transactions and reserve requirements, as well as verification of available LMRs that could help reduce system load if called upon. Note that at this point, MISO only verified the LMRs; i.e., the Maximum Generation Alert does mean that it issued scheduling instructions for the LMRs to modify their load by a certain time, for a given duration. Source: Reliability Coordinator Information System (RCIS) log.

[55] Under the mandatory Reliability Standards, each RC (e.g., MISO, SPP, TVA, SeRC) is required to "perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day [sic] will exceed SOLs and Interconnection Operating Reliability Limits (IROLs) within its Wide Area," as well as an Operating Plan to address any potential SOL and IROL exceedances revealed by the OPA. IRO-008-2 R1&R2. Transmission Operators have a similar requirement to perform daily OPAs, and prepare Operating Plans to address the OPA's findings, under TOP-002-4 R1&R2. See Appendix B, "Primer on Electric Markets and Reliable Operations of the BES," for more information on the RCs' OPA processes.

[56] Planning coordinators and transmission planners use voltage criteria in planning for future BES conditions for their respective footprints, which includes N-0 (no contingencies) and N-1 (outage of a single BES element or "single contingency"). However, the January 17, 2018 event was an "N-many" condition, due to the numerous generation outages during that timeframe. For more information on voltage criteria requirements applicable to transmission planners and planning coordinators, see NERC

Figure 16: Comparison of Transmission Planning Voltage Criteria (Percent) – Low Limits for Relevant RC Footprints in the Event Area

Nominal Voltage Level	SPP RC	MISO South Region	TVA RC	Southern/ SeRC
Normal (N-0) Low Limits:				
500 kV	---	97.5%[1] / 95%	98% / 95%[2]	98%
345 kV	95%		97%[3] / 95%[2] / 94%[4]	---
230, 161, 138, 115 kV	95%	95%		95%
N-1 Low Limits:				
500 kV	---	95%	98%	97%
345 kV	92%[5] / 90%		95%[3] / 90%	---
230, 161, 138, 115 kV	92%[5] / 90%	92%[6] / 90%		92%

[1] Entergy transmission planning criteria for EHV levels.
[2] AECI transmission planning criteria.
[3] For TVA load-serving buses. Criteria is 98% for non-load-serving buses.
[4] LGE-KU transmission planning criteria.
[5] AEP Central-Southwest transmission planning criteria.
[6] Entergy transmission planning criteria for HV levels.

The analyses and resulting next-day Operating Plans were completed by late afternoon on January 16, and thus could not reflect the significant amount of additional unplanned generation outages, derates and failures to start which occurred overnight, and the impacts of the higher power transfer levels and decreased system voltage levels resulting from those losses.

3. Alerts Issued Before January 17

Taking into account the extreme below average colder temperatures, elevated system loads, and unplanned outages that had already occurred, and the extreme temperatures and elevated system loads expected to continue, RC operators took the

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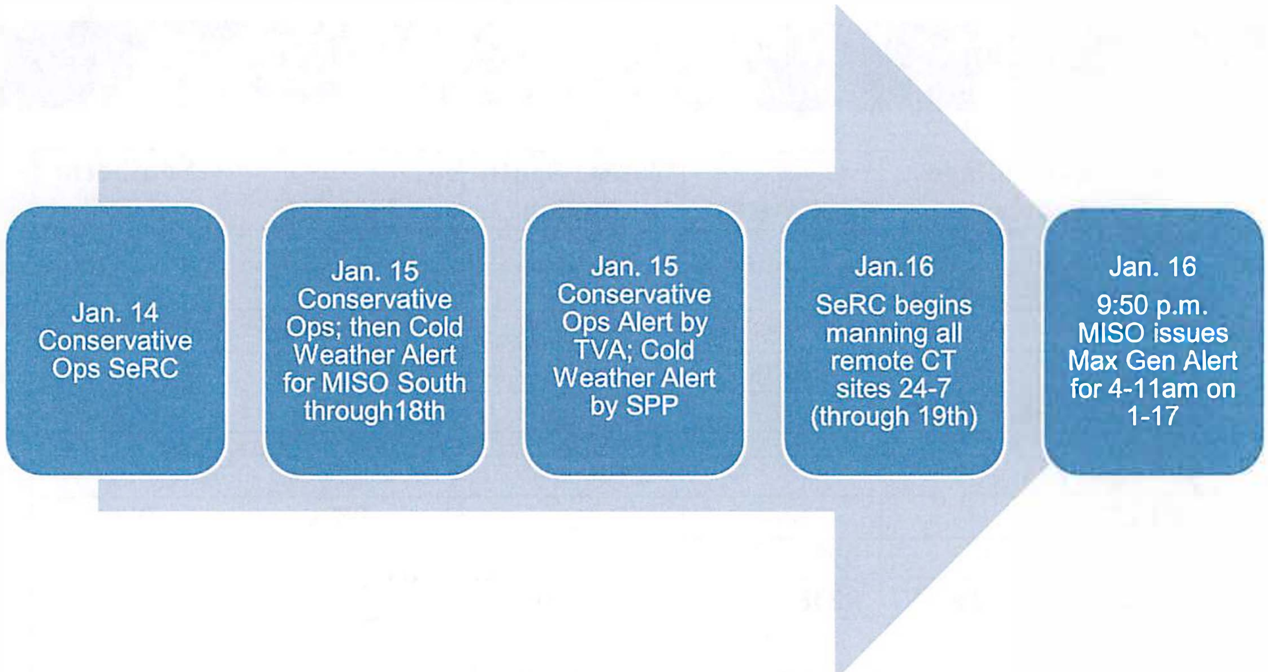
Reliability Standards, Transmission Planning (TPL), TPL-001-4 - Transmission System Planning Performance Requirements, Requirement R5 at 7, available at https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States following measures ahead of January 17, 2018:

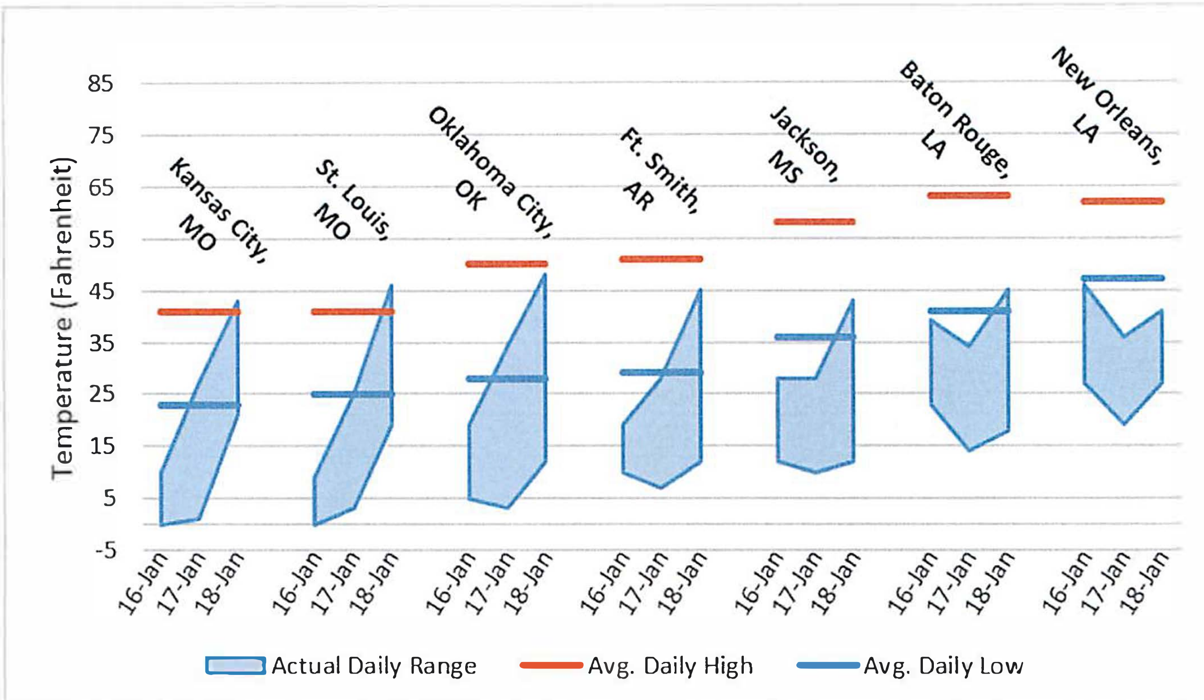


V. January 17, 2018 Event: Additional Generation Outages, Extreme Below-Normal Cold Weather Conditions, and Wide-Area Constrained Transmission System Conditions

A. Extreme Weather and Record Peak Loads

In addition to the arctic air, the weather front on January 14 to 17 brought snow and ice to parts of the Midwest, South and East. Temperatures in the Event Area dropped far below normal lows, as shown in the tables below. While not record lows, New Orleans recorded its lowest temperature in 29 years, while Little Rock, AR experienced the lowest temperature in 22 years.

Figure 17: Comparison of Actual Highs and Lows to Average Daily High and Low Temperatures, January 16 through January 18, 2018



By early January 17, every Mississippi county reported icy roads.[57] In addition to having the potential to freeze certain components of open-frame generating units, the icy conditions caused the loss of six (3-230 kV and 3-115 kV) transmission facilities, which occurred the evening of January 16 and during the early morning hours of January 17 in Southern Louisiana, and significantly degraded the transfer capability in that area.

As shown in Figure 18, most of the affected entities' peak loads on January 17 exceeded their forecast 2017-2018 winter peak loads. Further, the January 17, 2018 peak loads for both the SPP footprint, and for the MISO South region reached all-time highs for the winter season - breaking previous winter peak records, and nearing MISO South's all-time summer peak demand of 32,700 MW.

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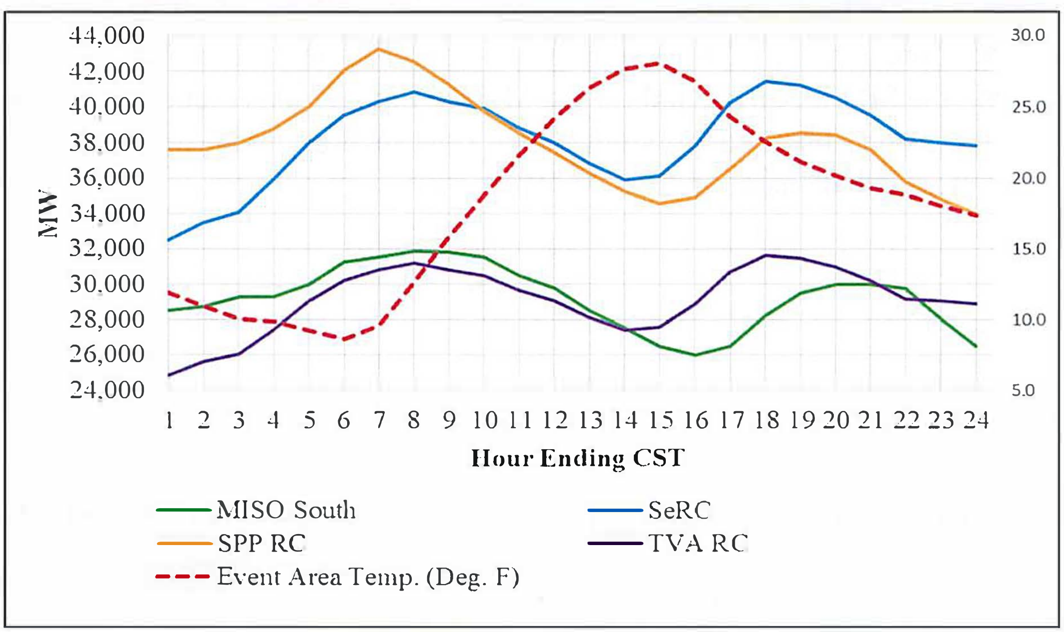
[57] Source: The Weather Channel (weather.com) January 17 2018 09:00 P.M. EDT (https://weather.com/storms/winter/news/2018-01-14-winter-storm-inga-midwest-northeast-south-snow-forecast-mid-january)

Figure 18: **January 17, 2018 Peak System Loads for Relevant Entities**

	All-Time Peak Winter Loads	Seasonal Forecast 2017-2018 Winter Peak Load	Actual January 17, 2018 Peak Load	Difference
	(MW)	(MW)	(MW)	(%)
MISO BA (total)	109,300	103,400	106,100	3%
MISO South footprint	31,100	28,400	31,582	11%
SoCo BA*	45,900	41,054	41,600	1%
SPP BA	41,500	41,129	43,584	6%
TVA BA**	33,352	31,925	31,640	-1%
* Actual peak occurred January 18, 2018:			44,400	8%
** Actual peak occurred January 18, 2018:			32,509	2%

As frigid air moved into the region, it increased system loads for each of the entities. While it is not abnormal for weather patterns to influence hour-by-hour electric use, the below-normal temperature pattern resulted in sharp increases in system loads due in part to electric heating demands throughout the early morning hours, as shown in the following illustration.

Figure 19: **January 17, 2018 System Loads and Average Event Area Temperature**



B. Growing BES Problems Due to Generation Outages and Derates

- *Unplanned generation outages and derates continued*
- *Throughout the night, MISO focused on meeting MISO South forecast load for morning peak (7-8 a.m. CST)*

At the time MISO issued the Maximum Generation Alert (as described in section IV.C above) for its MISO South region on January 16 at 9:50 p.m. CST, it forecast the following operating reserve conditions for the peak hour, from 7 to 8 a.m. CST:

- Forecast load plus operating reserve requirement:[58] 33,300 MW
- Economic maximum generation:[59] 32,891 MW
- Forecast imports into MISO South: 166 MW
- Projected energy **shortfall** for MISO South: **243 MW**

By the start of January 17, 2018, the Event Area, normally rich in generation capacity, had lost nearly 22 percent of its approximately 118,000 MW of generation by planned and forced outages and derates. MISO South was the hardest hit, with 11,600 MW outaged or derated, while SPP's southern footprint had approximately 8,300 MW outaged/derated. TVA RC had 5,000 MW outaged/derated in its RC footprint, while SeRC had only 1,400 MW outaged/derated.

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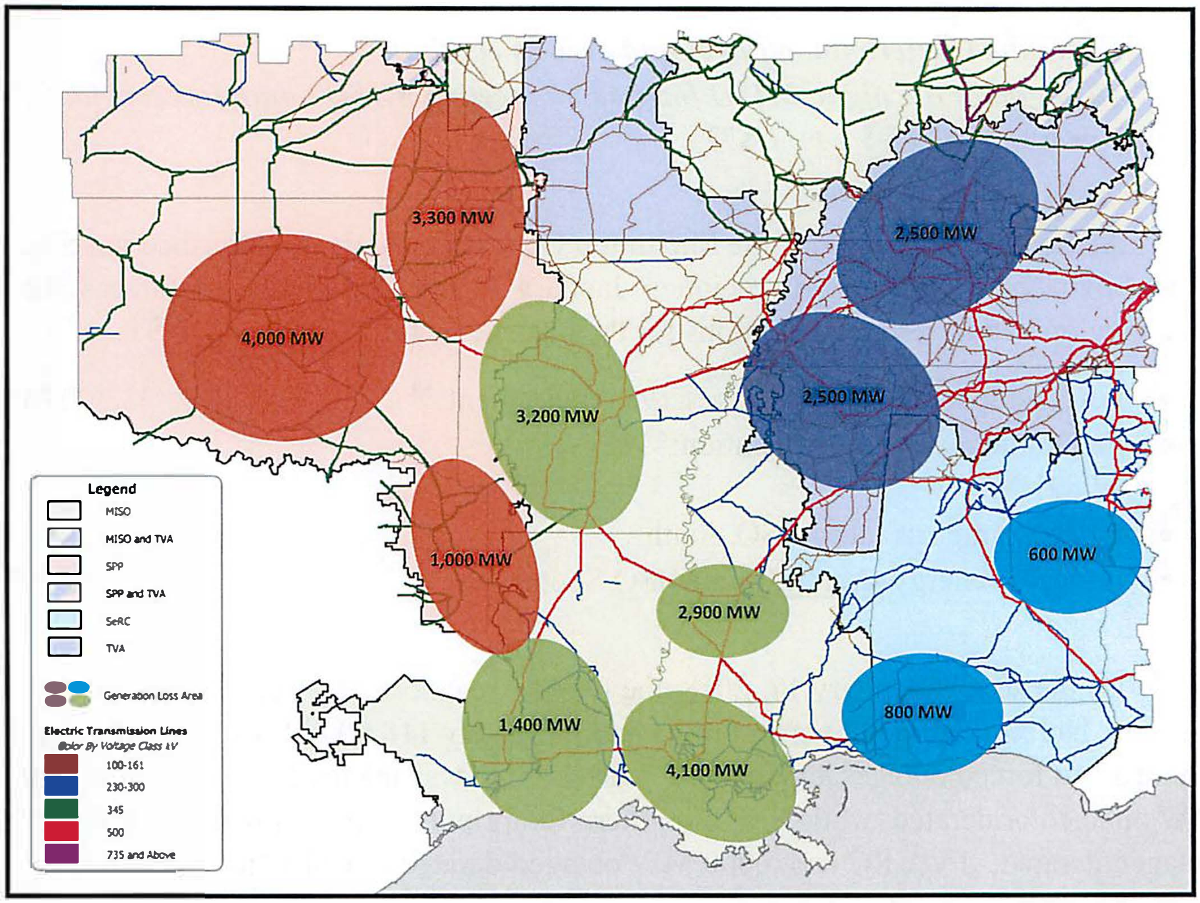
[58] MISO's operating reserve for its MISO South sub-area is defined in its FRAC as equaling the forecast load, plus the single worst contingency in MISO South (normally 1,415 MW but 1,163 MW on January 17), plus a load forecast uncertainty of 5%.

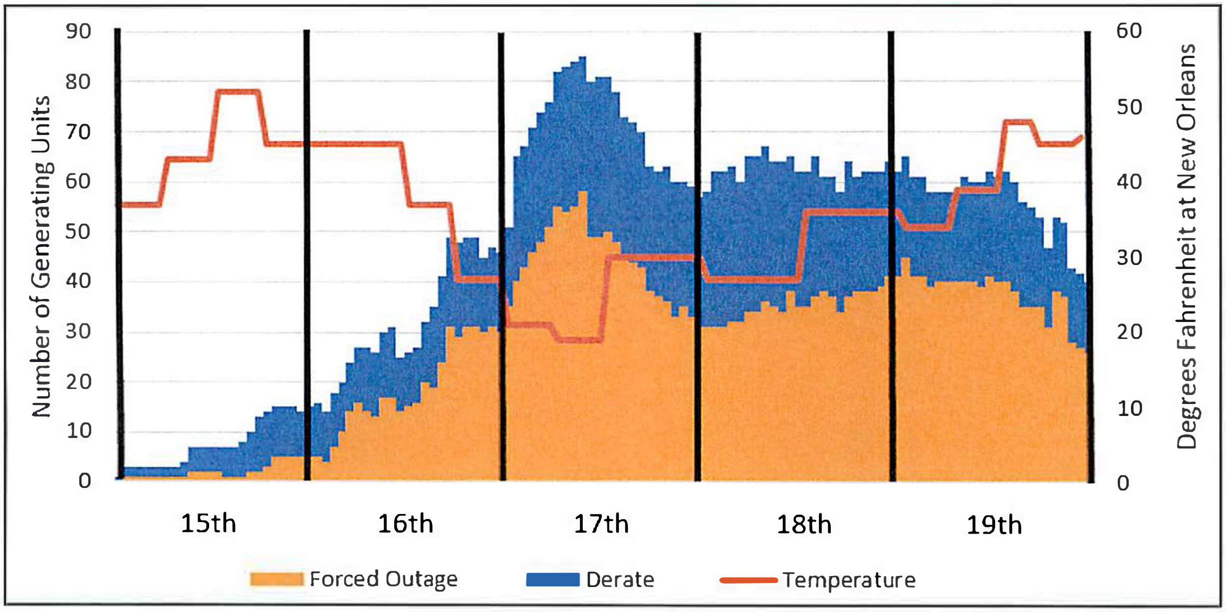
[59] Includes MISO north-to-south intra-market RDT schedule of 3,000 MW.

Figure 20: Total Generation Outages and Derates Within the Event Area, Beginning January 17, by Approximate Geographical Area



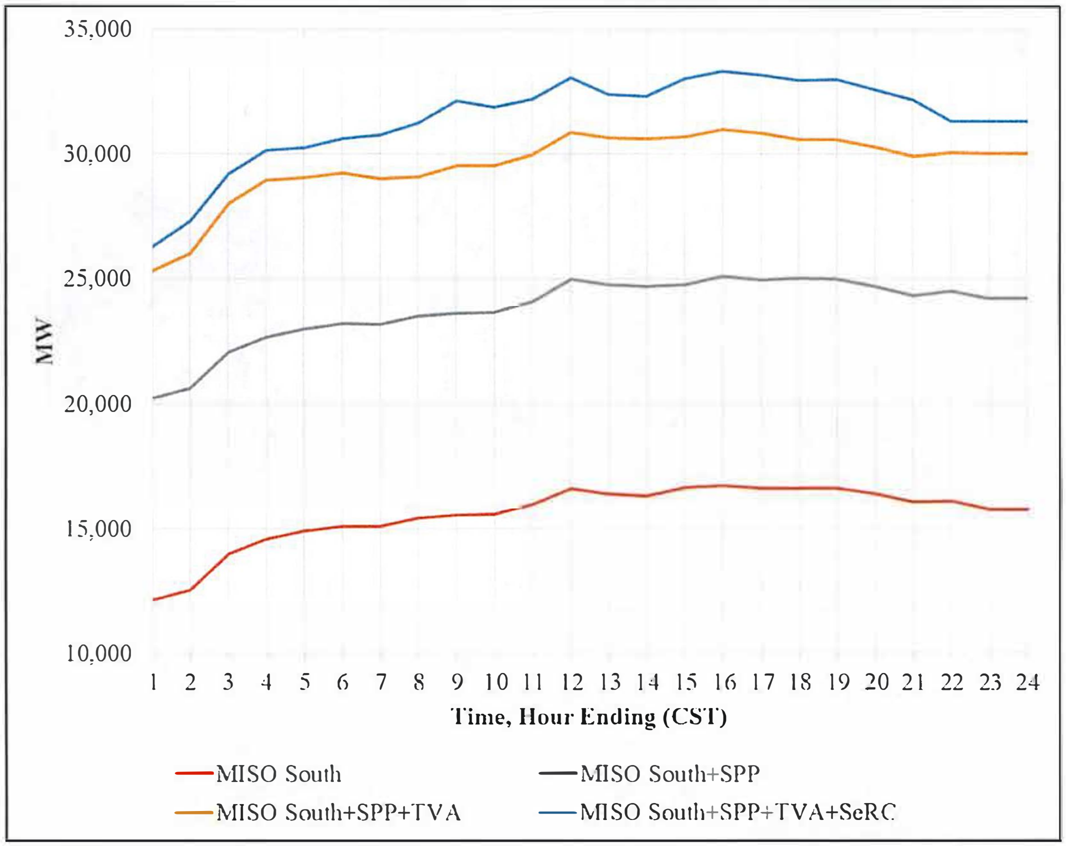
However, none of the RC/BA entities had anticipated what was to occur overnight—that the Event Area was about to lose a significant amount of additional generation at the same time that system loads would increase due to severe cold.

Figure 21: **January 15-19, 2018 – Number of Generation Unit Outages and Derates Versus Temperature, by Hour, for Event Area**



Through the early morning hours of January 17, as the winter storm and cold weather conditions moved across the region, additional unexpected generation outages and derates caused BES reserve margins to further decrease. The chart below illustrates the trend in total generation outages on January 17, 2018 for the Event Area, which peaked at approximately 33,500 MW.

Figure 22: Total Unavailable Generation over Time, for January 17, 2018, by RC Footprint



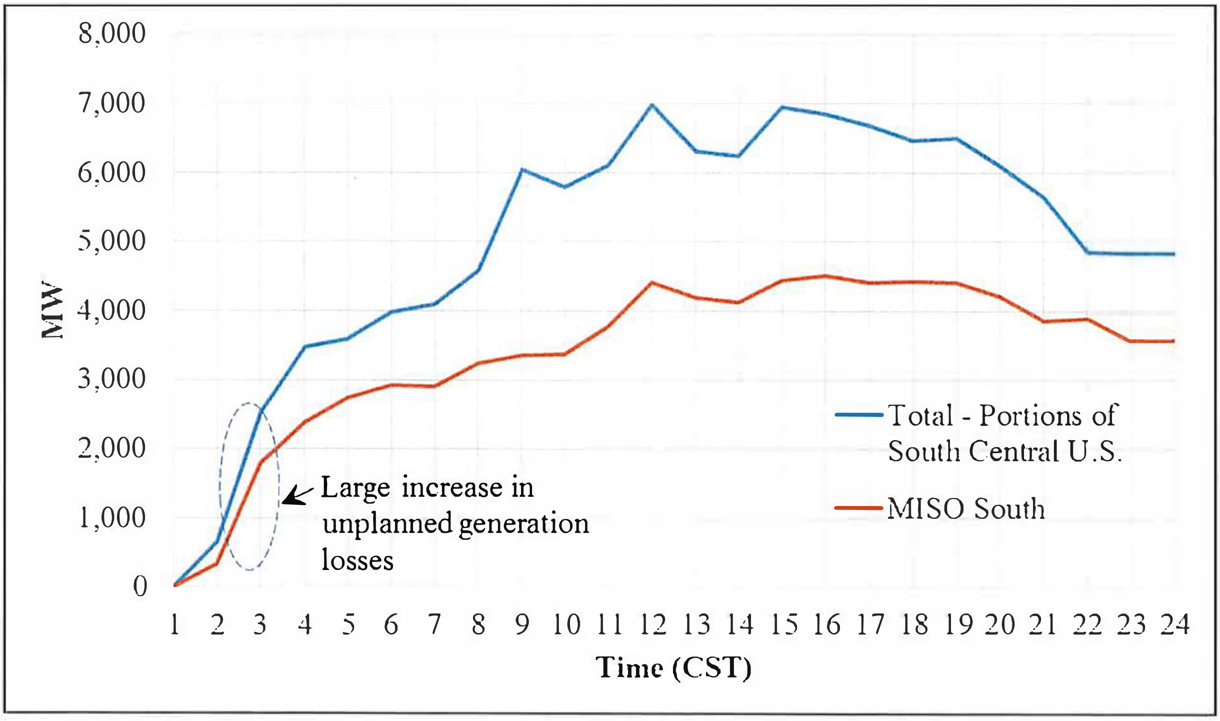
MISO South, especially, could ill afford these outages and derates as it already had lost generation output equivalent to approximately 40 percent of its seasonally-forecast winter peak load of 29,000 MW by the start of January 17. But by 8 a.m. that same day, MISO South would lose generation equivalent to nearly 50% of its forecast winter peak load.

Figure 23: MISO South Region Approximate Generation Outages and Derates at the Start of January 17, 2018, and by Hour Ending 8am Central Time

	Planned Outages	Pre-existing Unplanned Outages	By Hour Ending 8am, Additional Unplanned Outages	Total
	(MW)	(MW)	(MW)	(MW)
MISO South	4,000	7,600	3,400	**15,000**

As these additional unplanned generation outages and derates in MISO South unfolded in the early hours of January 17 (see Figure 24), MISO realized it had insufficient available generation capacity to meet its MISO South load (forecast to be at a morning peak load level between 7:00 and 8:00 a.m. CST) and would have to rely on emergency purchases and north-to-south RDT flows.

Figure 24: Total Incremental Unavailable Generation in the Event Area for January 17, 2018



Shortly after MISO's above-illustrated increase in unplanned generation outages and derates, it declared an Energy Emergency Alert (EEA) Level 2, and a Maximum Generation Event Step 2 a/b for the MISO South region, due to forced generation outages and higher than forecast load.[60] Under this declaration, MISO verified commitment of all available resources, and directed load serving entities within the MISO South footprint to initiate public appeals for voluntary load reductions, as well as other load management steps to reduce system load. At the time MISO issued the EEA Level 2, it forecast the following operating reserve conditions for the peak hour, ending at 8 a.m. CST:

[60] Reliability Coordinator Information System (RCIS) log. MISO has specified in its protocols certain triggering events that require taking action to prevent uncontrolled loss of firm load. In doing so, it has patterned its emergency protocols on the Reliability Standard EOP-011-1 – Emergency Operations, which prescribes EEAs to be declared for Energy Emergencies. EEA Level 2 declares that load management procedures are in effect.

- Forecast load plus operating reserve requirement:[61] 33,300 MW
- Emergency maximum generation: 29,593 MW
- Forecast imports into MISO South: 3,000 MW[62]
- Projected energy **shortfall** for MISO South: **707 MW**

As part of the EEA Level 2/Maximum Generation Event, MISO sent Load Modifying Resources scheduling instructions for 900 MW of load reduction for hour ending 7 a.m. through hour ending 10 a.m. Central.[63] At the same time, realizing that voluntary load reduction alone might not alleviate the shortfall, MISO contacted Southern Company to see if MISO could purchase emergency energy for MISO South to provide sufficient supply for the peak hour from 7 to 8 a.m. Emergency purchases from Southern Company for the MISO South capacity shortfall would also equally decrease their calculated north-to-south RDT.

1. By 2 a.m. CST: BES Transmission Conditions Become a Growing Concern

- ***System loads increasing***
- ***Transmission congestion first occurs***
- ***MISO issues Transmission Loading Relief (TLR)[64] for transfers sinking in TVA BA***

With increasing generation outages and derates in the Event Area continuing through the early hours of January 17, as part of their real-time monitoring of the BES, SPP's operators observed that their real-time contingency analysis (RTCA)[65] results began to show intermittent transmission congestion with flows into portions of the south central U.S.: simulated post-contingency limit exceedances for two transmission facilities in southeast Kansas bordering southwestern Missouri (as shown in the figure below by the orange circles).

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[61] See fn. 58.

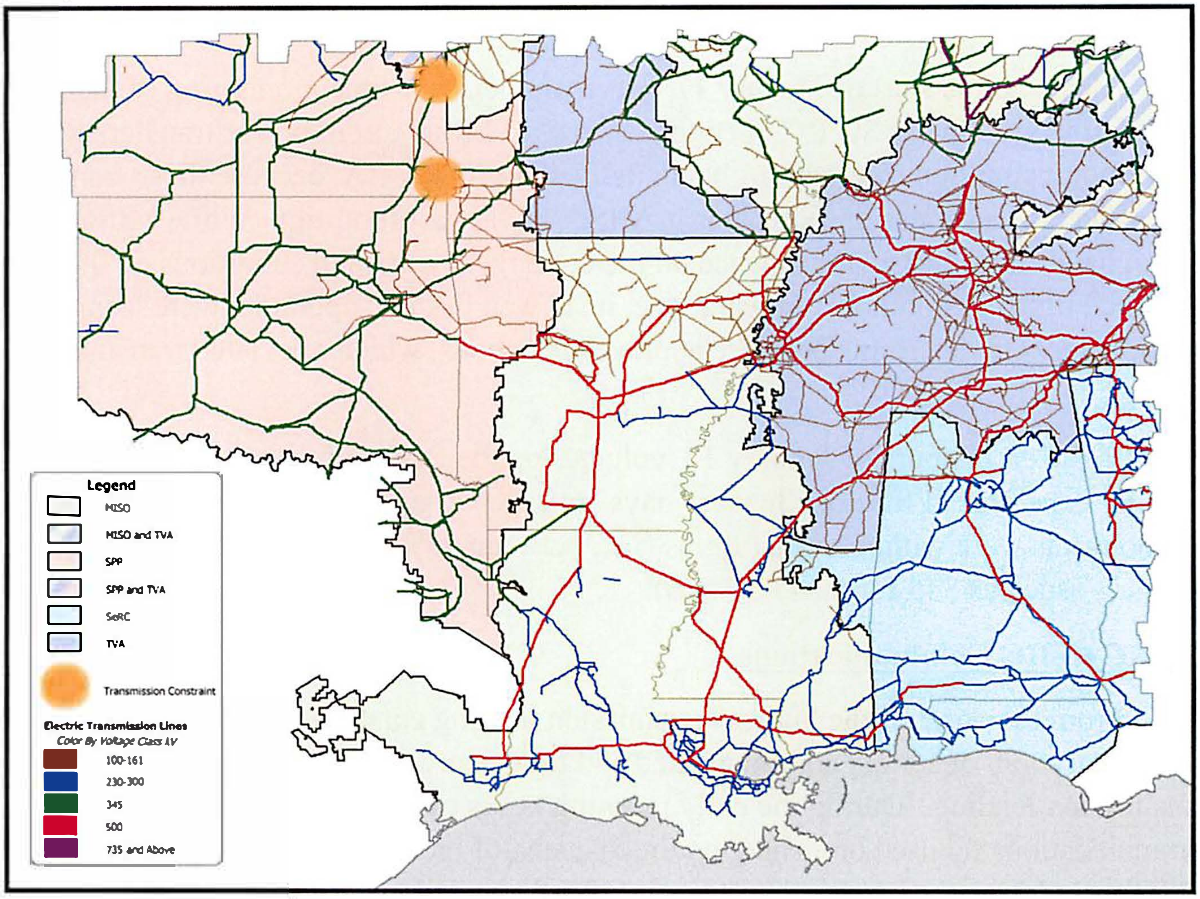
[62] MISO's north-to-south intra-market RDT schedule of 3,000 MW.

[63] Item 9_LMR Performance During January 2018 Maximum Generation Event.pdf

[64] See Appendix C, "RC and [Transmission Operator] Tools and Actions to Operate the BES in Real Time."

[65] See Appendix C.

Figure 25: By 2am CST – BES Transmission Congestion Began to Occur



Southerly Power Flows and Situational Awareness of Conditions

The effects of simultaneous southerly power transfers began to constrain the BES. These transfers included MISO's RDT, which by the start of January 17 was approaching 2,600 MW (1,000 MW firm transmission capacity and 1,600 as available non-firm transmission service). In addition to the RDT flow, the more-southern of the congested facilities illustrated above, in southeastern Kansas/southwestern Missouri, was also known to be impacted by flows from neighboring non-market areas, as well as SPP and MISO wind.[66] Further, the flows on SPP's transmission facilities in this congested area

[66] SPP Market Monitoring Unit, State of the Market Winter 2018 at page 32, available at https://spp.org/documents/56890/spp_mmu_qsom_winter_2018.pdf.

would have been increased by nearby unplanned generation outages and derates in SPP.[67] SPP's operators later performed generation redispatch and discussed the potential need to open the congested facilities.[68]

Also near the start of January 17, based on their real-time monitoring of the MISO transmission system, MISO RC operators issued a TLR to curtail power transfers with non-firm transmission reservations being delivered to TVA BA, because those transfers were affecting transmission flowgates in MISO's Midwest footprint. While MISO's TLR did not have any significant influence on the contingency loading conditions on the congested transmission lines shown above, it showed that RC operators were using their real-time tools to determine and take appropriate actions, which alleviated transmission loadings.[69]

In the early hours of January 17, voltages on the BES were close to what SPP typically experienced for prior January days, and prevailing BES voltages across the four RC footprints were within normal limits (i.e., between 95% and 105% of the "nominal voltage"—such as 345 for a 345 kV bus).

Key RC-to-RC Communications

From the onset of the higher transmission loading conditions, the SPP and MISO RC control room operators communicated and took coordinated actions to alleviate transmission loading. During the early morning hours of January 17, the operators' communications focused on managing the dispatch of increasing wind generation output. MISO's actual wind generation on January 17 substantially exceeded its forecast, as the following graphic shows.

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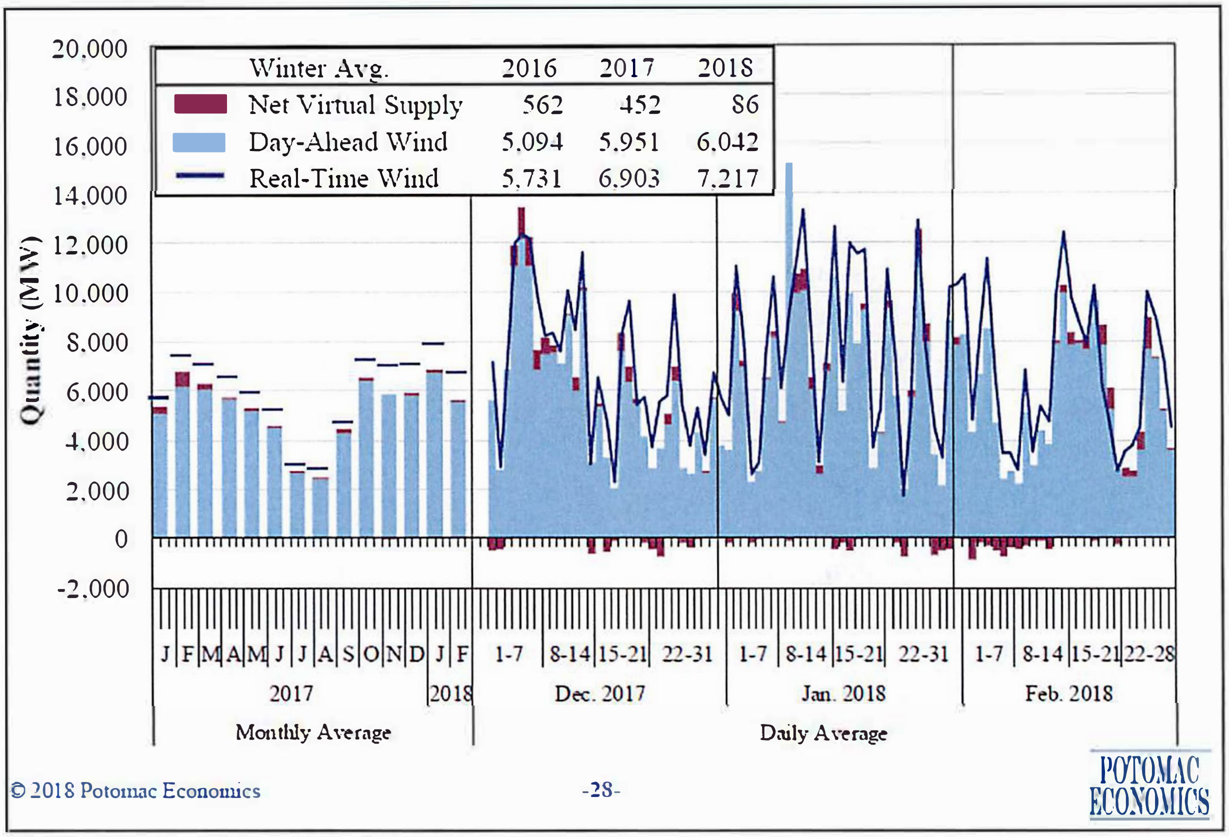
[67] Southwestern Missouri had over 750 MW of unavailable generation during the Event. Transmission flows to serve SPP's firm network transmission customer loads in that area would have contributed to the congested flows.

[68] 3:53 am call transcript.

[69] See Appendix C. Under the mandatory Reliability Standards, each RC (e.g., MISO, SPP, TVA, and SeRC) shall ensure that a real-time assessment is performed at least once every 30 minutes, for the purpose of prevent BES instability, uncontrolled separation, or cascading. IRO-008-2, Requirement R4. Transmission Operators have a similar requirement to perform real-time assessments, under TOP-001-4, Requirement R13.

Figure 26: **MISO Wind Forecast Versus Actual for Winter 2017-2018**



Beginning at 1:04 a.m. CST, in an effort to effectively dispatch increasing wind generation output while avoiding transmission overloads, MISO and SPP RC operators agreed to activate market-to-market binding constraints on several wind-affected flowgates. As the output of wind generation increased, the RC operators continued close coordination in managing these flows throughout the morning hours.

At 1:29 a.m. CST, MISO, SPP, TVA RC, and SeRC, among other RCs, held a normally-scheduled conference call to discuss daily outlook conditions. Both MISO and SPP predicted that their load for the January 17 morning peak (7 a.m. – 8 a.m. CST) would exceed their historic winter peak loads. The MISO South RC operator explained that MISO South was "at the point where we have no reserves" and that MISO would be asking to exceed the RDTL of 3,000 MW and seeking energy from its neighbors, especially Southern Company, because transfers from Southern Company provided one-for-one credit when calculating the RDT.[70] SeRC and TVA RC reported that they were in conservative operations. SPP reported its projected morning peak load of 42,500 MW

[70] 20180117 0229 Call transcript.

would exceed its all-time winter peak by five percent, and that it had sufficient reserves to cover its forecast peak.

MISO measured its RDT flow by two methods, in real time using load and generation telemetered values sourced from State Estimator (often referred to by MISO and SPP as "raw"), and through its Unit Dispatch System (UDS), which runs every five minutes for the upcoming five minute interval (looking 10 minutes out). According to the Regional Transfer Operations Procedure in effect during the Event (RTO-RTOA-OP1-r0 (effective date February 1, 2016)), MISO operators would track, and act on, the UDS rather than the real-time measurements. On January 17, MISO's real-time/raw and UDS RDT flow measurements diverged substantially at times. For example, at 2 a.m., the real-time RDT was approximately 2,700 MW in a north-to-south direction, but only 2,183 according to the UDS.

2. By 6 a.m. CST: BES Energy Emergency and Wide-Area Constrained Transmission Conditions

- ***Unplanned generation outages and derates continued, as temperatures reached their lowest levels***
- ***System loads increased as the forecast morning peak load approached***
- ***Stranded reserves in northern MISO, RDT flows increasing***
- ***MISO declared Energy Emergency, arranged emergency purchases***
- ***Increasing wide-area transmission congestion***
- ***Transmission reconfiguration steps taken to address some congested facilities***
- ***For other congested facilities, RC operators relied on post-contingency firm load shedding***
- ***BES voltages trending lower***

Figure 27: By 6 a.m. CST – Unavailable Generation, Total and as a Percentage of Event Sub-Area Capacity

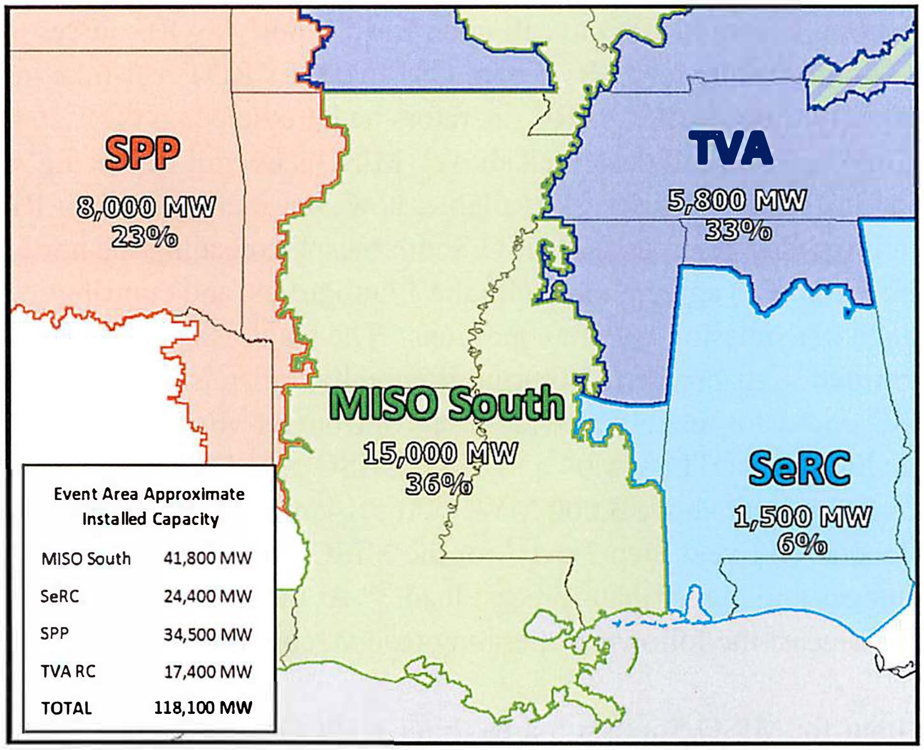
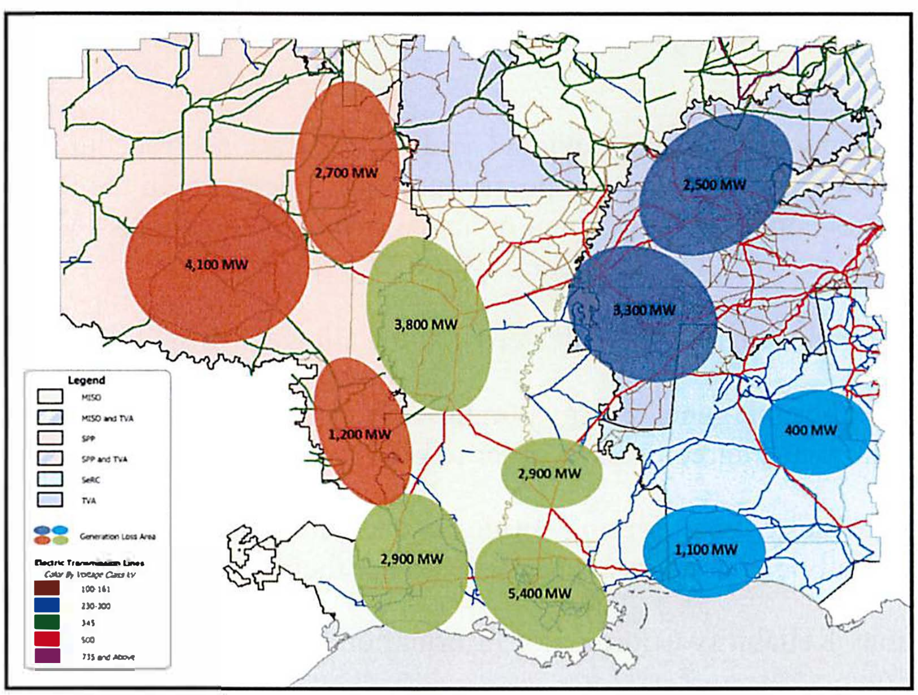


Figure 28: By 6am CST, Total Generation Outages and Derates Within the Event Area, by Approximate Geographical Area



Deliverability of MISO reserves

As described earlier, when MISO declared an EEA Level 2/Maximum Generation Event Step 2 a/b, it allowed MISO to call upon Load Modifying Resources to effectively reduce MISO South system load. By 5 a.m. CST, MISO's RDT real-time metered[71] flow reached 3,000 MW, just as MISO's RC operators had predicted on the 1:29 a.m. CST scheduled RC conference call described above. MISO's overall Balancing Authority Area footprint had sufficient reserves available; however, increasing their RDT scheduled flow to aid in providing reserves for MISO South meant exceeding the north-to-south scheduling limit (RDTL) agreed upon with the Joint Parties, and contributing to the wide-area constrained transmission system conditions. The result was that MISO had reserves that were **stranded** in its northern footprint, limited by transmission system constraints. Because MISO could not reliably provide reserves from its Midwest to its South region without exceeding the RDTL, at 5:04 a.m. CST, MISO asked SPP to agree to raise the RDT north-to-south limit above 3,000 MW.[72] At 5:14a.m. CST, MISO declared a Maximum Generation Event Step 2 c/d[73] for the MISO South region, justified by forced generation outages and higher than forecast load.[74] At the time MISO made this declaration, it forecast the following operating reserve conditions:

- Peak hour for MISO South sub-area (hour-ending): 08:00 CST

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[71] MISO's RDT flow is metered by using the net actual interchange flow for the MISO South footprint, as a means to track their performance in meeting their RDT scheduled flow.

[72]Under the version of the Regional Transfer Operations Procedure in effect during the Event, a party could request a temporary increase or decrease in the RDT to avoid a system emergency, or address emergent or actual system emergencies. Version RTO-RTOA-OP1-r0, section 3.3.1. See page 71 for SPP's response.

[73] Maximum Generation Event steps c and d allowed MISO to:

- Make emergency energy purchases from neighboring BAs through existing Emergency contractual agreements in order to conserve Operating Reserves

- Requested load serving entities to enact load modifying resources to now include issuing public appeals to reduce demand per their internal procedures.

[74] Source: Reliability Coordinator Information System (RCIS) log.

- Forecast load plus operating reserve requirement:[75] 33,300 MW
- Emergency maximum generation: 32,000 MW[76]
- Forecast imports into MISO South: 800 MW
- Projected energy **shortfall** for MISO South: **500 MW**

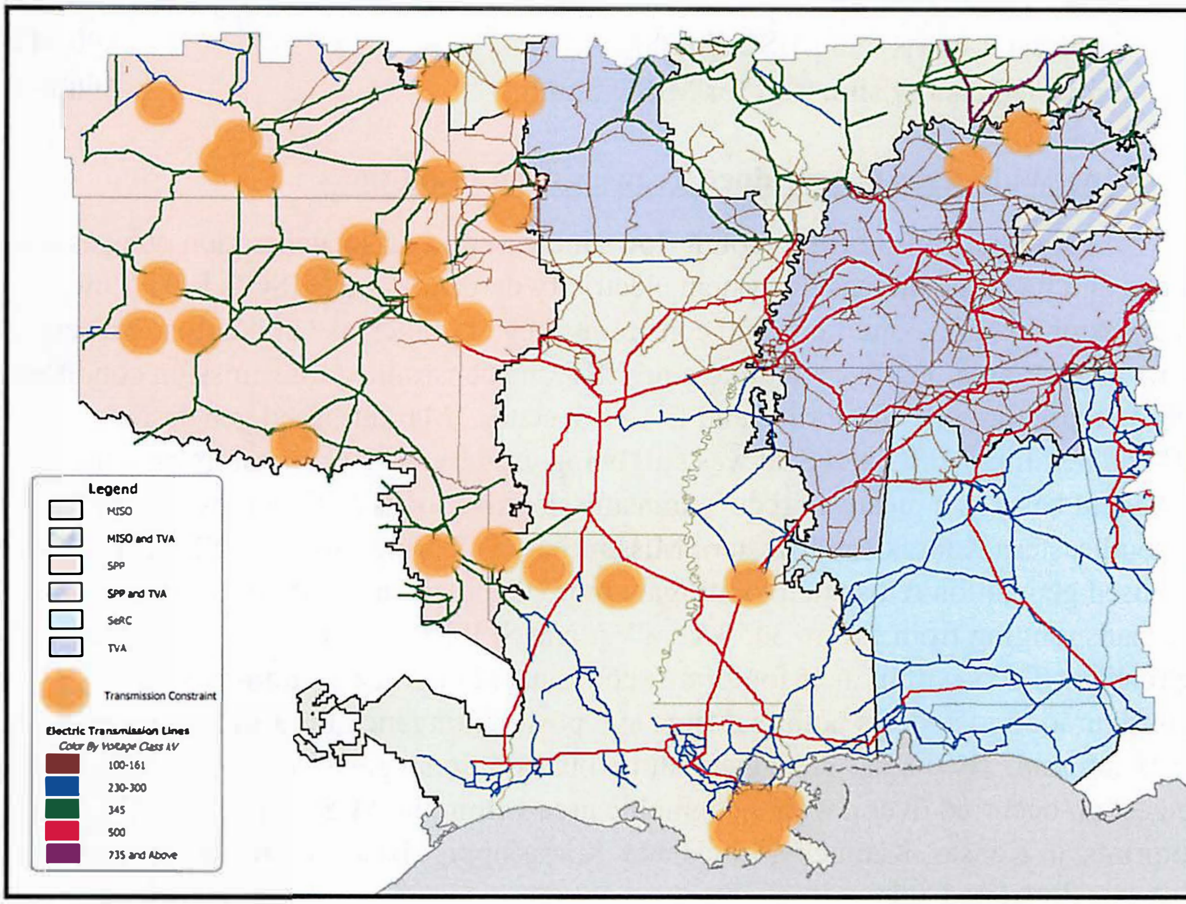
Increasing Wide-Area Constrained Transmission Conditions

As simultaneous north-to-south flows increased to offset generation outages and derates and meet the increasing system electricity demands and MISO's RDT flow, transmission loading conditions and constraints began to increase in number and severity, across a wider area. From 2 a.m. to 6 a.m. CST, the constrained transmission conditions spread across three RC footprints and five U.S. states. Market-based generation redispatch within MISO and SPP was still being used by the RC operators on a pre-contingent basis as a means to reduce transmission overloads as they arose, including in the southeastern Kansas/southwestern Missouri area. During this time, SPP and TVA RCs used generation redispatch to mitigate more than a dozen post-contingency overloads ranging from 115 to 345 kV. TVA and SPP RC operators, in agreement with the relevant TOPs within their footprints, coordinated their use of transmission reconfiguration to address both real-time and post-contingency limit exceedances during this timeframe. By 4 a.m., there were numerous additional areas where transmission congestion occurred over a wide geographic area within the MISO, SPP, and TVA RC footprints, in Kansas, Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, and eastern Texas, as illustrated below:

[75] See fn. 58.

[76] Includes MISO north-to-south intra-market RDT schedule of 3,000 MW.

Figure 29: **By 4 a.m. CST – Numerous Additional Transmission Constraints for Wide-Area of South Central U.S.**



Critical Role of Accurate Facility Ratings

Opening a BES transmission facility (transmission reconfiguration) to alleviate an actual overload, or to prevent a post-contingency limit exceedance, is one of the more consequential operator actions. Generally, except for planned maintenance, new construction, or to aid in restoration from an outage, transmission facilities are not reconfigured (e.g. opened). On the morning of January 17, as southerly simultaneous transfers placed unpredicted additional loading on the transmission system,[77] operators began studying the option of transmission reconfiguration to address system overloads. As RC operators acted to manage congestion via methods such as generation redispatch, they noted that some of the power flows would approach the facilities' respective SOLs intermittently, and then decrease in flow. But over time, the operators found that some

[77] The southeastern Kansas/southwestern Missouri congested facility was projected only to be at 80% loading, not congested, based on SPP's day-ahead Operational Planning Analysis for January 17, 2018.

facilities ceased the intermittent flow patterns previously described, and their actual flows remained near their SOLs, which required additional operator action. The rising power flows caused the RC operators to study the opening some of these facilities; but before taking action, the RC operators verified flows and their associated SOLs.

The RCs were using SOLs based on transmission facility ratings established by the Transmission Owners.[78] For the most part, these ratings reflected the expected ambient conditions (i.e., winter/low ambient temperatures). In general, using SOLs based on the colder temperatures afford more capacity to transfer needed power to locations within the Event Area.[79] For example, Southern Company enabled SeRC to have what it called "dynamically rated" transmission lines, based on the extremely cold weather, which effectively raised the SOLs, allowing more power to reliably flow.[80] Had SeRC used static limits (e.g., year-round/summer limits), it would have needed to employ significant generation redispatch (detrimentally impacting BA contingency reserves), possible transmission reconfiguration, and/or TLRs.

However, SPP monitored flows on certain facilities in the Event Area using SOLs that were based on average ambient conditions (warmer weather) rather than on the

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[78] Under the mandatory Reliability Standards, each Transmission Owner is required to have facility ratings based on their methodology, which includes consideration of "ambient conditions (for particular or average conditions or as they vary in real-time)." FAC-008-3 – Facility Ratings. These facility ratings form the basis for the RCs' SOL methodologies for the operating horizon (FAC-011-3), which is required to be used by Transmission Planners (TPs) and Transmission Operators (TOPs) in establishing SOLs. FAC-014-2.

[79] Some SOLs are based on facility ratings of transmission line equipment which is located at the termination points of the transmission line (e.g., protection systems), and do not vary based on the ambient conditions. Transmission Owners commonly strive to upgrade this terminal equipment so that it does not result in limiting the full utilization of the capacity of overhead transmission line investment.

[80] Southern Company dynamically rated the lines by applying temperature-adjusted limits that were based on the facilities' ratings for 30 degrees, instead of using static winter limits, due to the extremely cold weather during the Event. These ratings better-reflected the current ambient conditions (e.g. 16 degrees for one facility).

colder weather conditions of January 17.[81] On the morning of January 17, to address the constrained system conditions, SPP operators consulted with their TOP operators to verify these SOLs to aid in determining potential mitigation measures. If the ratings and SOLs had reflected cold weather ambient conditions, SPP may have been able to avoid some of the generation redispatch and transmission reconfiguration measures they took on the morning of January 17.[82]

In addition to using appropriate SOLs, system operators must carefully study the potential outcomes before using transmission reconfiguration, to ensure that reconfiguring one facility does not place the BES in a less reliable state, such as by shifting the power flow and overloading other BES transmission facilities, or contributing to localized low voltage conditions on the sub-transmission system. The Team reviewed documentation showing that the RCs performed one or more studies before using transmission reconfiguration. For example, during the 4 to 6 a.m. timeframe, TVA RC operators observed that a heavily-loaded transmission facility in northeastern Oklahoma approached 100% of its pre-contingency limit.[83] TVA RC analyzed the situation and worked with the local TOP to perform transmission reconfiguration to alleviate the overload.

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[81] Within a week of the Event, the following were daytime high temperatures for select cities within the Event Area:

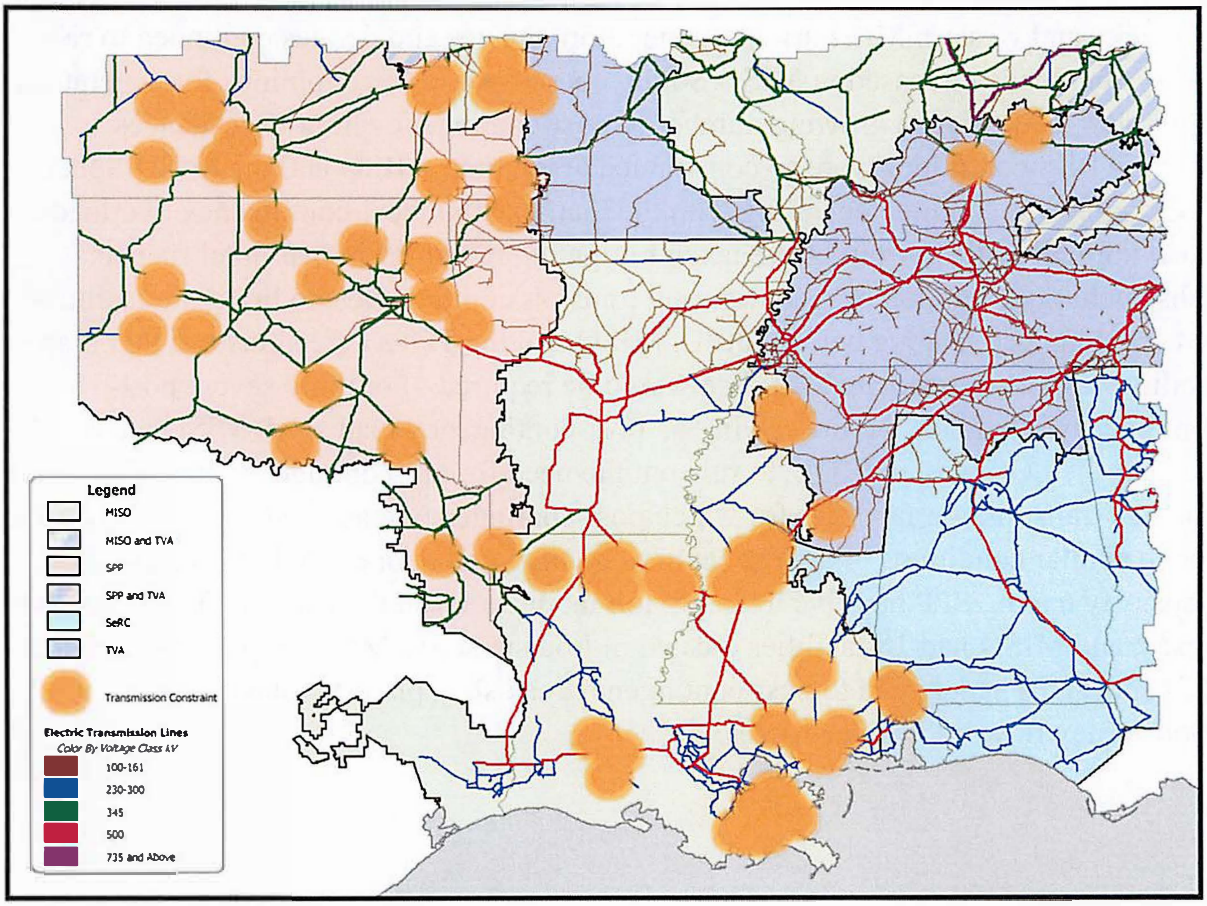
- Kansas City: 64 degrees, on January 21, 2018
- Springfield, MO: 70 degrees, on January 21, 2018
- Tulsa, OK: 70-72 degrees, on January 20-21, 2018
- Little Rock, AR: 66 degrees, on January 21, 2018

[82] The Team noted that for several facilities, including the southeastern Kansas/southwestern Missouri mentioned earlier, the transmission facility limits the operators were using reflected lower summer season limits, versus ratings one would expect to see for winter ambient temperature conditions, which normally allow for higher power transfers to occur.

[83] Even though this facility had a relatively low limit for a 138 kV facility due to a relay limitation (114 MVA, which was especially low as compared to a conductor limitation for the prevailing colder weather conditions), the RC operators were required to operate the BES to the limits set by the Transmission Owner, and to take actions necessary to maintain reliability.

Between 4 and 6 a.m., the RCs had nearly exhausted their less-consequential options, yet system loads and transmission congestion continued to increase. TVA and MISO RCs issued two TLRs to curtail non-firm transmission schedules for flowgates in Kentucky and western Missouri. As generation outages and derates continued to rise, and system loads increased in MISO South, operators had fewer options for generation redispatch to alleviate a growing number of post-contingency limit exceedances. Because BES conditions were so constrained at the time, MISO and the MISO South TOPs agreed to continue operating with the then-existing post-contingency overloads, when normally MISO would have taken mitigating measures in real time, such as redispatching generation or reconfiguring transmission facilities, to bring the facilities' post-contingency loading below 100%. MISO and the TOPs agreed instead that if any facility was lost, immediate load shed would be required. For more severe post-contingency overloads, before relying on post-contingency load shed, MISO analyzed whether the SOL was an IROL, to rule out the need for pre-contingency load shed. SPP also had transmission facilities for which post-contingency load shed was the only option, due to similar conditions of area generation outages and derates, and elevated system loads. By 6 a.m., SPP had five transmission facilities located mostly in Oklahoma and Texas, and MISO had 18 facilities located in Louisiana and Mississippi, for which the RCs and TOPs had agreed to post-contingency load shed plans to alleviate post-contingency flow limit exceedances.

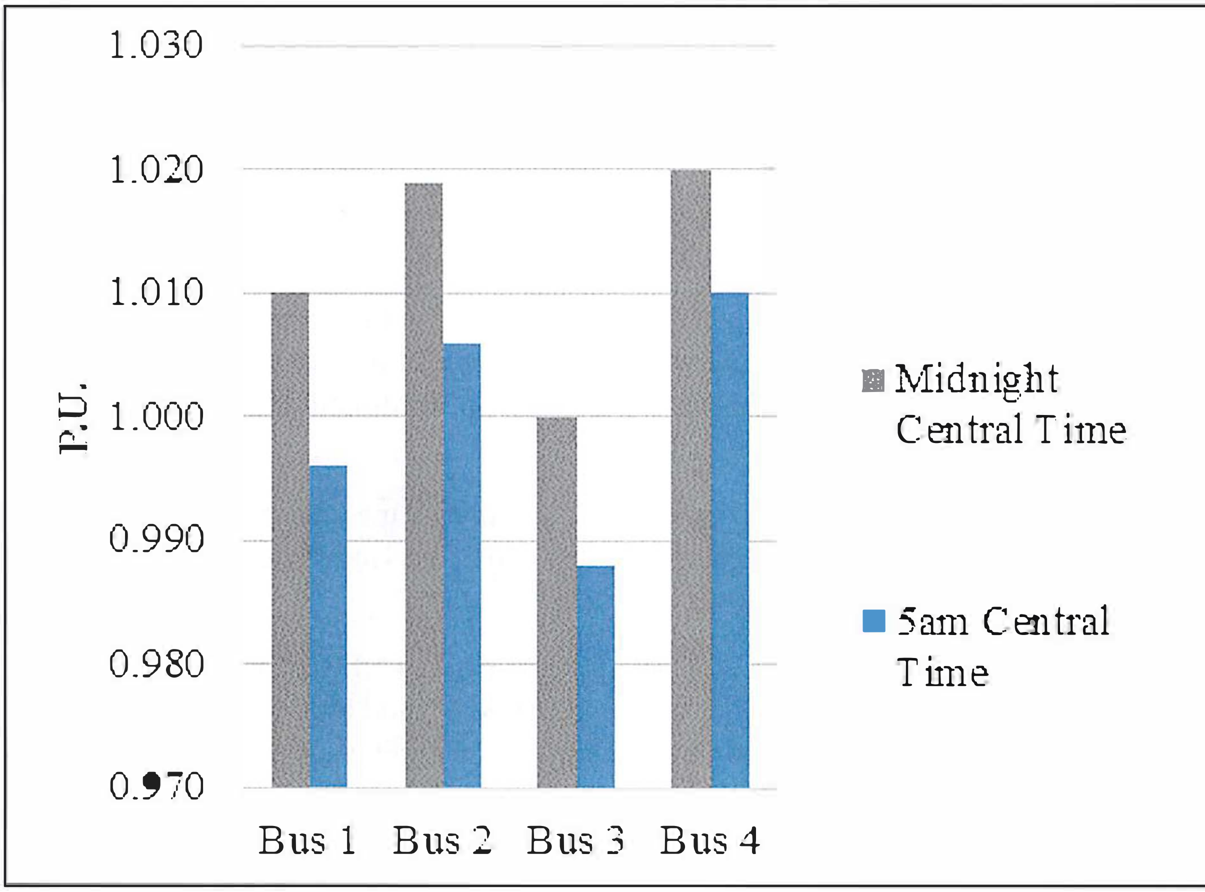
Figure 30: **By 6am Central – Further Transmission Constraints Occurring Over a Wide-Area of South Central U.S.**



BES Voltage Patterns

During the early morning hours, RC operators monitoring BES transmission flows, congestion, and voltages noted a lower voltage level pattern in certain locations within the Event Area, compared to what they typically would experience on high load days in January. While BES voltages predominantly remained within limits across the Event Area from the start of January 17 until approximately 5 a.m. CST, EHV real-time bus voltages for certain areas had decreased as compared to midnight, as shown in the chart below.

Figure 31: **5am Central: Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Voltages, Early Morning Hours of January 17, 2018**



By 5:57 a.m. CST, one of MISO's 500 kV busses dropped below 97.5%, and remained below this level for approximately four hours. Its lowest level was 96.2%.

Key RC-to-RC Communications

During this early-morning timeframe, on a regularly-scheduled conference call among MISO, SPP, TVA RC, SeRC, and other Eastern Interconnection RCs, the MISO operator warned that MISO South was "about tapped out," and that MISO was contemplating the issuance of a Max Gen Alert/EEA 1, at which point it would "curtail interruptible loads" and "would be asking the parties to the transfer agreement . . . if we could go above that 3,000 MW transfer limit which we're pretty close to right now." MISO noted that it had just lost an "800 MW unit which . . . was our cushion," and that "we're . . . at the point where we have no reserves and we would be . . . asking neighbors for help." MISO said it would try "to import as much from Southern [Company] as possible because it's a one-to-one credit on our [RDT] transfer agreement."

MISO and SPP RC Operators communicated regularly and cooperated to mitigate system conditions during the early morning hours leading into the peak. For example, at

2:58 a.m. CST, SPP and MISO RC operators spoke by phone to discuss the status of their congestion management efforts. The MISO operator asked about the southeastern Kansas/southwestern Missouri congested flowgate and SPP responded that it was close to overloading in real time and had been "near the top" of its simulated post-contingency loading for an extended period. SPP indicated that it would need to open the flowgate if it were to suffer the outage of the next most-severe contingency. The MISO operator offered to activate/bind the constraint and perform market-to-market redispatch between SPP and MISO, in an effort to alleviate loading conditions on SPP's congested flowgate.[84]

At 5:04 a.m. CST, MISO emailed SPP, TVA and Southern Company, asking to raise the RDT north-to-south limit above 3,000 MW (as its operator had earlier predicted), although the RDT would not exceed 3,000 according to the UDS until 7 a.m. In support, MISO noted:

> MISO is in extremely tight conditions and is forecasting an expected Winter peak for the South Region of 33,911 MW for Hour Ending 0800. Previous Winter peak is 30,930 MW.
>
> MISO has declared a Max Gen Event step 2a-b and a NERC EEA level 2 – due to [the loss of] a number of units (~3,000 MW) and transmission lines over the evening hours due to the cold weather and icing conditions.
>
> MISO is expecting the Regional Directional Transfer to be maximized flowing from North to South at the 3,000 MW limit and possibly exceeding the limit of 3,000 MW. Please consider that MISO has limited ability to reduce the flows on the RDT and would like for all to consider raising the limit.[85]

At 5:33 a.m. CST, as the morning peak hour (7 to 8 a.m.) approached for MISO South, MISO made an official request for emergency energy assistance to SeRC for the purpose of meeting its forecast load plus reserves obligations. Southern Company agreed to provide 700 MW of emergency purchase for a 4 hour period. For approximately an hour, MISO BA coordinated with Southern Company BA arranging for the purchase to start at 6:30 a.m. CST, in time for peak hour conditions.

At 5:39 a.m. CST, the MISO South operator informed SPP that the RDT was at its limit and asked about SPP's system conditions. The SPP operator noted that SPP had multiple flowgates with post-contingency overloads, and one real-time overload (which

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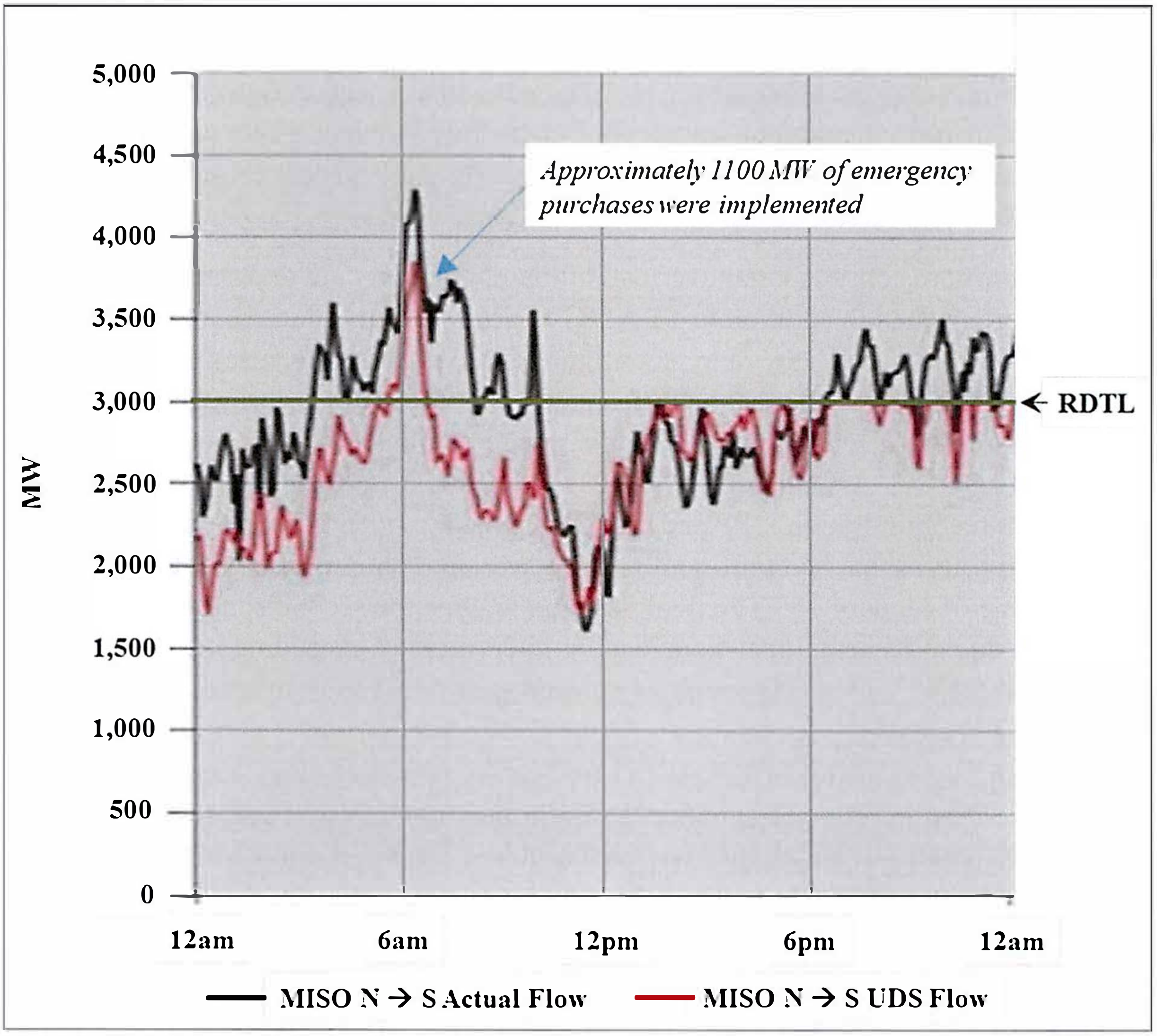
[84] 20180117 02:58 CST Call from MISO North to SPP RC.

[85] Email from MISO to TVA, SPP and Southern. See page 71 for response.

was mitigated by operator actions as described below). MISO told SPP that it was purchasing emergency power from Southern Company, and should SPP experience emergency conditions, MISO was prepared to take actions necessary to reduce the RDT. SPP indicated that it was not yet experiencing emergency conditions. Within five minutes, the MISO South RC operator had discussed the same information with TVA RC and SeRC. The Regional Transfer Operations Procedure in effect at the time did not clearly address specific actions to be taken when RDT flows were affecting adjacent RCs.[86]

Figure 32: **MISO Regional Directional Transfer – January 17, 2018**



[86] As a result of the Event, MISO, SPP, TVA and SeRC revised the Regional Transfer Operations Procedure; the revised version became effective in December 2018.

3. <u>By 8 a.m. CST:</u> **MISO Energy Emergency Continues and Four RCs Take More Consequential Steps to Maintain BES Reliability**

- ***System loads continued to increase as the morning load peaked from 7 to 8 a.m.***
- ***RDT peaked at nearly 1,000 MW over the RDTL***
- ***MISO South received emergency energy from Southern Company and TVA BA***
- ***Additional transmission reconfiguration/more consequential operator steps***
- ***Many next-contingency conditions that would lead to firm customer load shed in MISO South and SPP***

System operators were already facing dozens of post-contingency overload conditions as discussed above, but system loads were still increasing due to the severe low temperatures and the approaching morning peak load. Market redispatch or additional non-firm transmission interchange curtailment such as TLRs were less-available options during this timeframe, due to the excessive generation outages and derates in the Event Area.

As for more consequential overload mitigation actions, several transmission facilities were opened in addition to TVA RC's earlier transmission reconfiguration. SPP RC and its TOP operators agreed to reconfigure the southeastern Kansas/southwestern Missouri congested flowgate that had been studied multiple times during the Event, due to the actual/real-time loading of the facility now remaining above 100% of its normal limit of 203 MVA.[87] Also, based on SPP RC's additional study[88] to prepare for transmission reconfiguration, SPP and the TOP agreed to open the other facility in southeastern Kansas that had post-contingency overloads showing up in RTCA since late in the evening of January 16. The final decision to open the second southeastern Kansas facility was due to its actual/real-time loading intermittently exceeding its normal limit of 167 MVA at 5:15.[89] TVA RC operators worked with AECI TOP to reconfigure a 161

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[87] The Team noted that for this 161 kV facility, the transmission facility limits the operators were using reflected summer season limits (lower limits) versus winter ambient temperature conditions, which may have not required the RC operators to perform transmission reconfiguration.

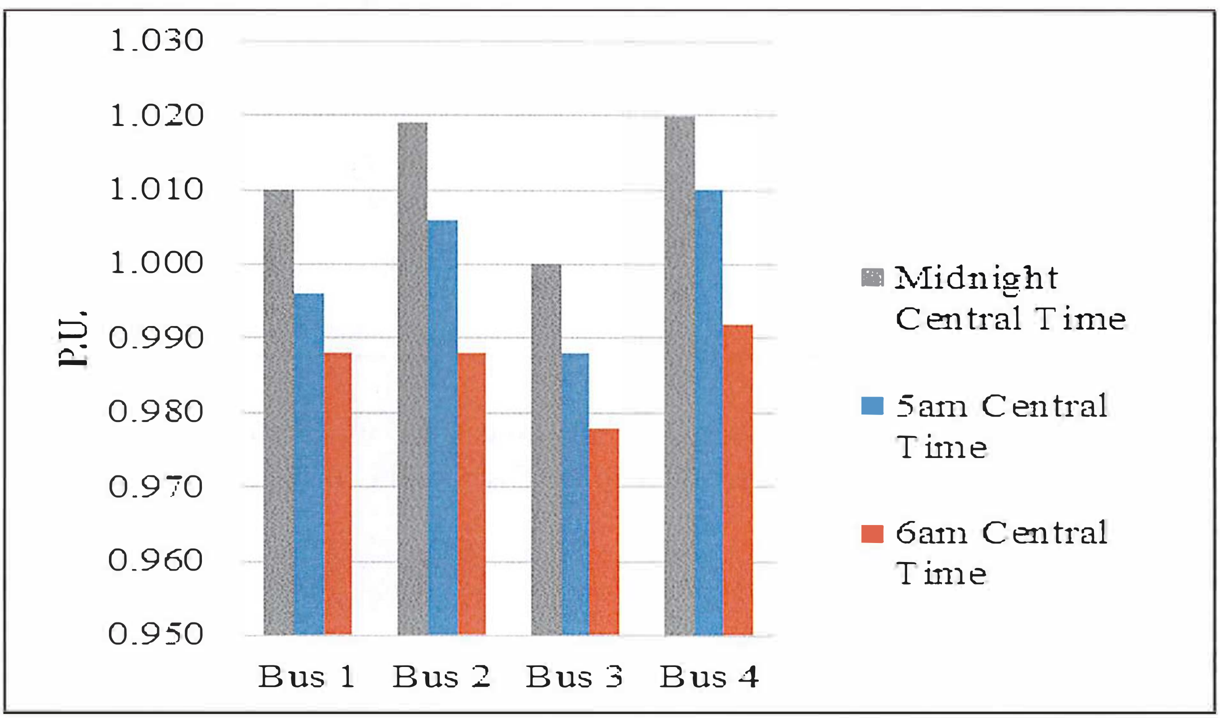
[88] SPP RC performed contingency analysis study at 7:07 a.m. CST, evaluating reconfiguration of this facility, and the study showed no resultant real-time SOL exceedances.

[89] The Team noted that for this 161 kV facility, the transmission facility normal and emergency (post-contingency) limits were of equal value. While this is a possibility for terminal-limited transmission lines, Transmission Owners typically address those

kV facility in southwest Missouri because its real-time loading exceeded 100% of its normal limit. By 8 a.m. CST, three other facilities remained open from earlier operator actions, and five others (one in TVA RC, four in Southeastern RC footprints) had post-contingency plans for reconfiguration. MISO operators, out of reserves in MISO South and prepared to shed firm load throughout MISO South for the WSC in MISO South, also had over 20 transmission facilities for which localized load shed would be necessary should the next contingency occur, all of which were in Louisiana and Mississippi, where MISO had suffered generation outages, derates, and failures to start. Approximately 20 of these facilities would require localized load shed if the same contingency (the MISO South WSC) occurred, while approximately six more facilities would require localized load shedding if additional contingencies occurred.

EHV real-time bus voltages trended downward between midnight and 6 a.m. in the southern Oklahoma portion of SPP's footprint, as shown in Figure 33 below.

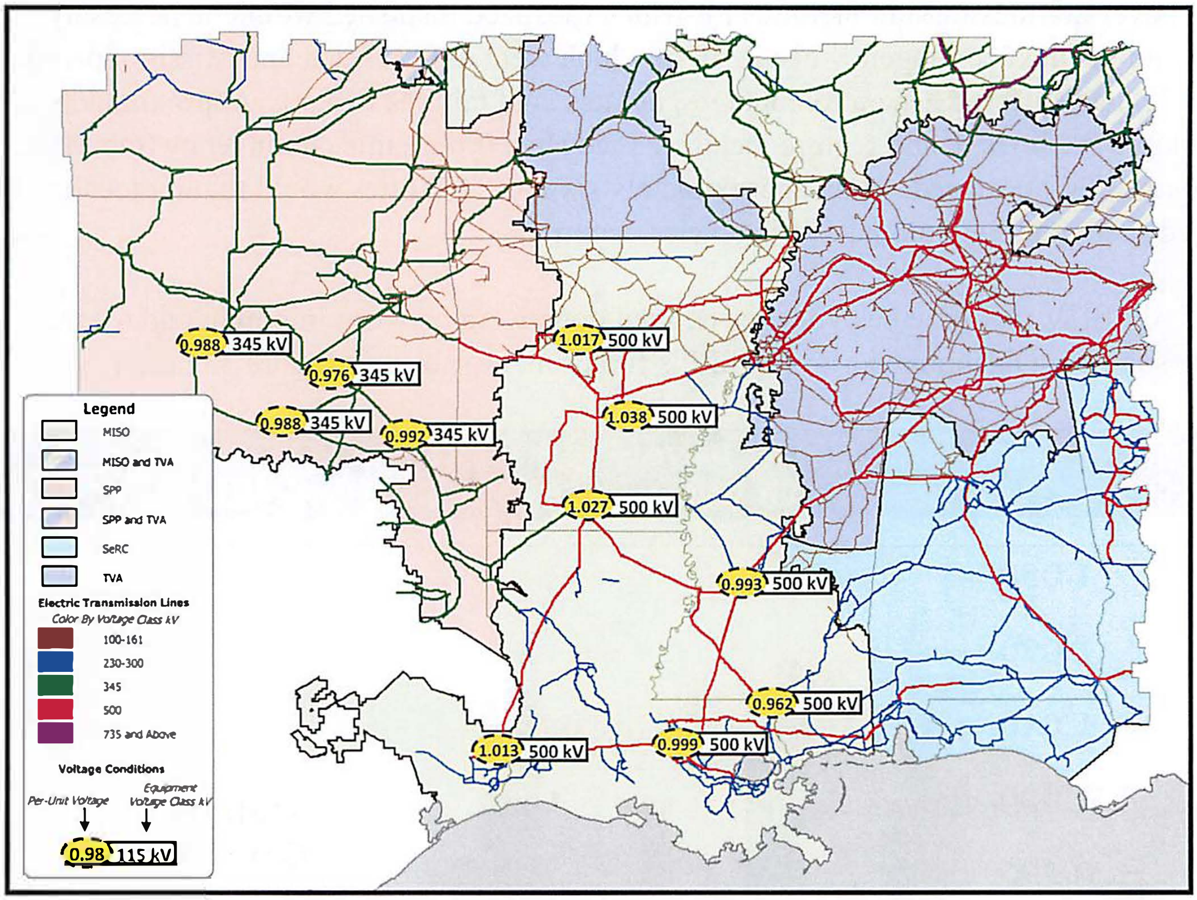
Figure 33: **6am Central: Further Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Per Unit Voltages, Early Morning Hours of January 17, 2018**



limitations early on to ensure they can achieve maximum value of their transmission facility investment to serve customers' needs. The Team also noted these limits reflected summer season limits (lower limits) versus winter ambient temperature conditions, which may have not have required the RC operators to perform transmission reconfiguration.

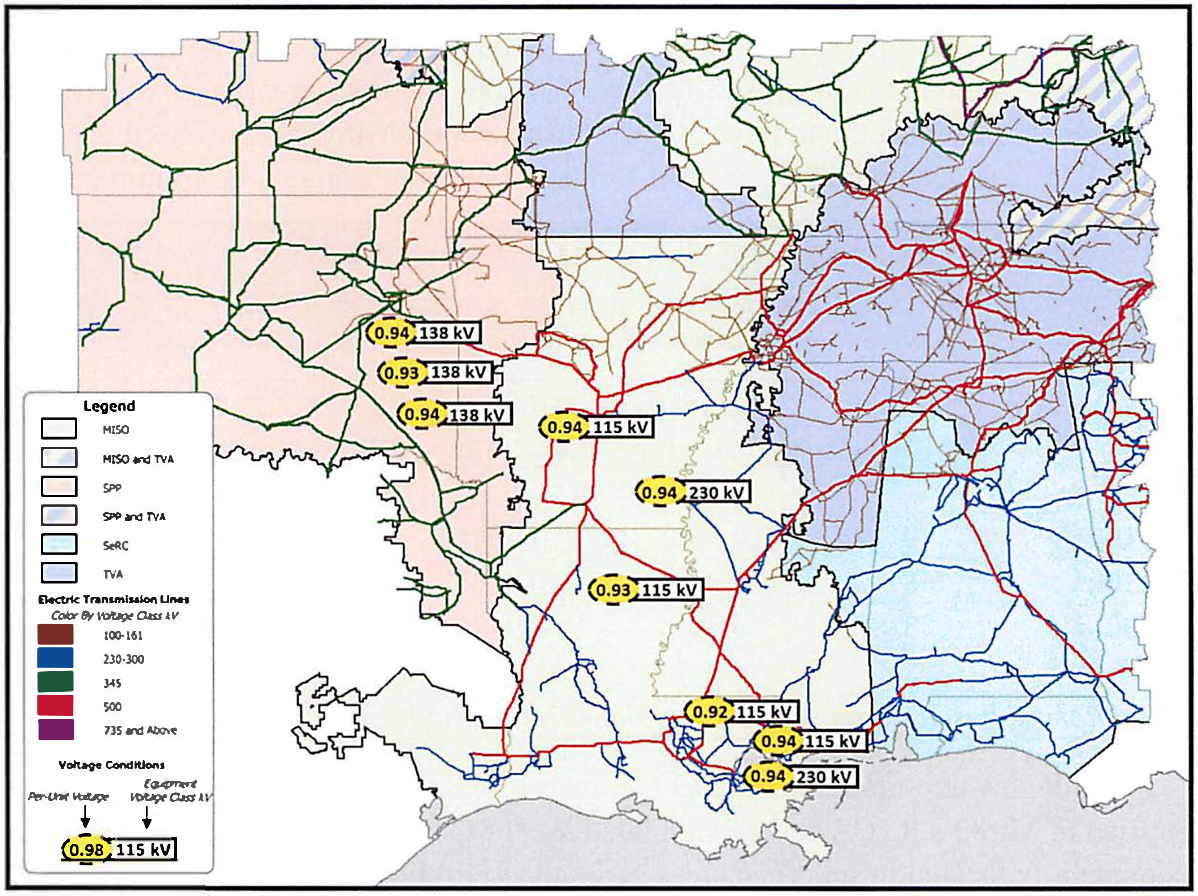
However, for the most part, EHV voltages in Arkansas, Louisiana, and Mississippi remained close to their nominal levels (i.e. 100% or 1 p.u.), as shown in figure 34 below.

Figure 34: BES Pre-Contingency Voltage Conditions (P.U.) for Select EHV Buses, January 17, 2018, Approximately 6am CST



Both SPP and MISO experienced low real-time BES voltages for several rural locations in southeastern Oklahoma, southern Arkansas, and Louisiana, as shown in Figure 35.

Figure 35: BES Voltage Conditions (P.U.) for High Voltage Buses below Normal (Pre-Contingency) Limits, January 17, 2018, Approximately 6am CST



It was clearly evident that real-time BES voltages were decreasing in some areas throughout the early morning hours of January 17, as shown in Figure 33. However, for the most part, EHV voltages remained near nominal levels, as shown in Figure 34. Furthermore, SPP and MISO experienced real-time voltages below 95% at several rural-located BES facilities in eastern Oklahoma, Arkansas, and Louisiana (ranging from 92% to 94% for several 115kV and 138 kV buses) as shown in Figure 35, as well as rural sub-transmission facilities (e.g., 69 kV) in southern Oklahoma and eastern Texas.[90]

[90] After review of similar rural location voltage data for the day before the event, the Team could not attribute all of SPP's rural location simulated post-contingency voltages to increased power transfers such as the RDT. Nonetheless, SPP identified mitigation measures (e.g., post-contingency capacitors for voltage correction) to address the conditions.

Impact of MISO South WSC for Both Reserves AND Number of Transmission Voltage Limit Exceedances

For the morning of January 17, the MISO South WSC outage of a single 1,163-MW unit would have left MISO South without adequate generation supply and also would have resulted in the most BES facility post-contingency low voltages (nine 115 kV buses, eight 230 kV buses, and three 500 kV buses) within MISO South, based on MISO's RTCA (as compared to the results of any other single simulated contingency).

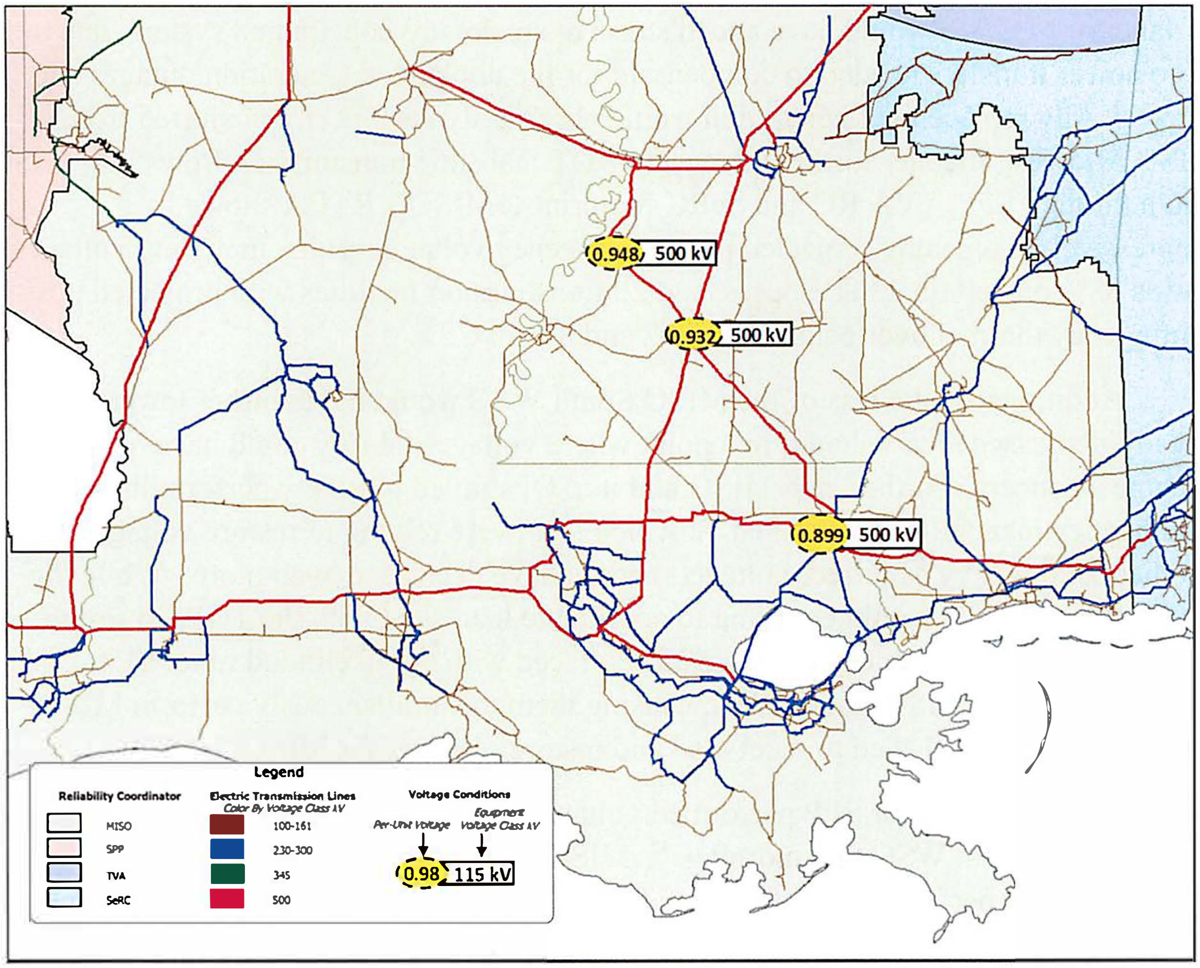
Figure 36: **BES Post-Contingency Range of Voltages below Limits for Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC**

	Number of Buses	Lowest P.U. Voltage	Highest P.U. Voltage	Mitigation Plan
115kV:	9	0.860	0.964*	Post-contingency load shed
230kV:	8	0.880	0.913	Post-contingency load shed
500kV:	3	0.899	0.948*	Post-contingency load shed

* *Monitoring based on nuclear power plant voltage limits.*

While it is important to note that the lowest BES voltages on MISO South buses identified in MISO's RTCA for the simulated loss of the MISO South WSC were predominantly located in suburban areas of southeastern Louisiana and southwestern Mississippi (north of the urban centers and the industrial corridor in southeastern Louisiana), MISO's 500 kV network simulated post-contingency voltages were also indicating lower voltages, as shown below. The MISO RC analyzed and discussed its RTCA post-contingent thermal and voltage violations with its TOP system operators, and they agreed on the post-contingent mitigation measures that would be taken in the event of the actual loss of the 1,163 MW generating unit.

Figure 37: **BES Post-Contingency Voltage Conditions (P.U.) Below Limits for EHV Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC**



The MISO RC analyzed and discussed its RTCA post-contingent thermal and voltage violations with the local TOPs' operators and developed post-contingent action plans. For the loss of the MISO South WSC, there were no unsolved contingencies within the MISO RTCA. This indicated to the MISO operators that upon the loss of any contingency, the area load pockets would remain stable and allow operators the time to implement post-contingent load shed to address each next contingency on a case-by-case basis. SPP also included the MISO South WSC in its RTCA, and relied on the fact that its RTCA case converged as an indicator of voltage stability.[91]

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[91] SPP's post-contingency results did not indicate any resulting low BES voltages within its footprint, but did confirm low voltages at the same buses in the MISO South region as projected by MISO's RTCA.

While winter season peak electricity demands in general impose less reactive power demand on the BES than summer peak conditions, and urban centers are generally less susceptible under winter peak load conditions to voltage instability than during summer peak load conditions, the loss of the MISO South WSC during the morning peak on January 17, 2018 would have added stress to an already-constrained system, due to the large power transfers needed to compensate for the unplanned generation outages and derates. Any replacement generation would necessarily have been transferred from MISO Midwest, thereby further increasing RDT real-time transmission flows into MISO South through SPP, TVA RC and SeRC footprints. MISO's RTCA showed progressively worsening projected post-contingency voltage results, including voltages as low as 88% on certain 230kV buses, and 20 transmission facilities with projected post-contingency thermal overloads between 7 and 8 a.m. CST.

Additionally, the loss of the MISO South WSC would have further lowered the already-depressed area voltages to a point where voltage stability could have quickly become a concern. Further, had MISO and its TOPs failed to timely perform the post-contingency manual firm load shed on which they were relying to restore voltages before another contingency occurred, voltage(s) could have decreased even more. While the MISO RC operators would be trying to coordinate load shed with the TOPs to restore voltages, they would concurrently have been faced with the likelihood of an EEA Level 3 for the loss of the MISO South WSC, causing them to simultaneously perform MISO South-wide firm load shed to meet load and restore reserves for MISO South.

Neither MISO nor SPP performed voltage stability analysis for the simulated loss of the MISO South WSC that morning.[92] MISO had online voltage stability tools, and SPP could have performed an offline study, however, preparing its offline study could have taken several hours and thus not provided timely results for the RC operators that morning. Voltage stability studies could have aided MISO and SPP in determining whether SPP needed to declare a system emergency and whether MISO needed to take pre-contingency steps to position their systems for the potential loss of the MISO South WSC. MISO was relying on the TOPs within its footprint to be able to promptly execute the necessary load shed to alleviate the numerous low voltages, if the MISO South WSC had occurred. Voltage stability analysis would be especially important given that MISO recognizes that one of its load pockets is "a voltage/thermal sensitive area and is susceptible to low voltages under outage conditions or a loss of a key transmission

[92] While voltage stability analysis is not specifically required by the Standards, RCs and TOPs are required to perform a real-time assessment which evaluates system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions. IRO-008-2, and TOP-001-4.

element." Sharing the voltage stability analysis with adjacent RC operators would give them another source of simulated post-contingency voltage data to determine if additional pre-contingency protective measures are needed.

Key RC-to-RC Communications

MISO's RDT flow hit its peak of 4,331 MW by real-time measurement, and nearly 4,000 MW as calculated by UDS, at approximately 6:30 a.m. MISO had already arranged 700 MW of emergency energy from Southern Company, but based on the latest projected supply and demand conditions in MISO South for the upcoming peak hour, beginning at 6:12 a.m. CST, MISO sought additional emergency energy from Southern Company, as well as from SPP and TVA BA. TVA BA had 300 MW emergency power available, and TVA BA and MISO arranged for its delivery, for a total of 1,000 MW the emergency power obtained ahead of the peak hour.[93] MISO's EMS automatically allocates the emergency purchases between MISO's North and South regions when calculating the RDT, taking into account transmission distribution factors. MISO expected the emergency purchases made for MISO South reserves to decrease the RDT, and shared this expectation with other RC operators. This expectation proved correct when the RDT did begin to decrease just after emergency power deliveries began.[94]

Just before the peak hour, SPP RC denied MISO's request to raise the RDT limit above 3,000 MW via email, and shortly thereafter, SPP notified MISO that it had emergency power available, but it was not deliverable to MISO South.

LMRs to Aid MISO South During Peak Load Conditions

As part of MISO's Maximum Generation Emergency/ EEA-2 procedures, MISO sent LMR[95] scheduling instructions (SI) for load reduction to help cover their MISO South peak load. MISO sent the SI just after MISO's declaration of EEA Level 2. The Team learned that the LMRs were not obligated to be available in the winter (only required in the summer season), and that long notification times limited the availability of some LMRs for the morning peak. MISO deployed a total of 700 MW of LMR on

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[93] In response to MISO's request for additional emergency energy above the 700 MW from Southern Company, Southern Company assisted MISO in obtaining an additional 150 MW of emergency energy from Southern Company BA during the peak hour.

[94] See Figure 32.

[95] See fn. 14.

January 17, but was able to increase its LMR to 930 MW by providing notice well in advance of the morning peak on January 18.[96]

4. <u>Post-8 a.m.-peak hour:</u> Conditions Gradually Improve

- ***System conditions improved after morning peak, as load demands dropped from peak levels***
- ***Generation conditions improved as units returned to service with rising temperatures***
- ***SPP wind generation decreased sharply after morning peak conditions***
- ***SPP EHV voltages returned to more typical levels***
- ***Many pre- and post-contingency measures remained in effect***
- ***MISO again sought emergency power as it prepared for evening peak***

After the morning peak on January 17, MISO South operators began to focus on evening peak reserves. MISO was still projecting the evening peak to be short of the necessary reserves for MISO South. Before 10 am, MISO RC Operators asked Southern Company if MISO could continue emergency energy purchases for the evening peak. MISO reduced its emergency energy to 350 MW until 1:30 p.m., after which it sought additional emergency energy for the evening peak (predicted to occur between 7 and 10 p.m. CST) from SPP, Southern Company and TVA BA. MISO briefly dropped down to EEA Level 1, returning to EEA Level 2 just before 2 p.m., when it declared Maximum Generation Event Step 2a/b and EEA Level 2 for MISO South effective 7 p.m. until early the morning of January 18. MISO finally dropped back down to EEA Level 1 at approximately 8 p.m. System conditions improved primarily due to the return of some of the generation units which had not been available during the early morning hours.

By 10 a.m. CST, SPP's EHV voltages returned to more typical voltage range for those locations. For example, the following chart shows a comparison between earlier morning real-time voltage levels and those measured at approximately 10 a.m. CST, for southern Oklahoma EHV locations:

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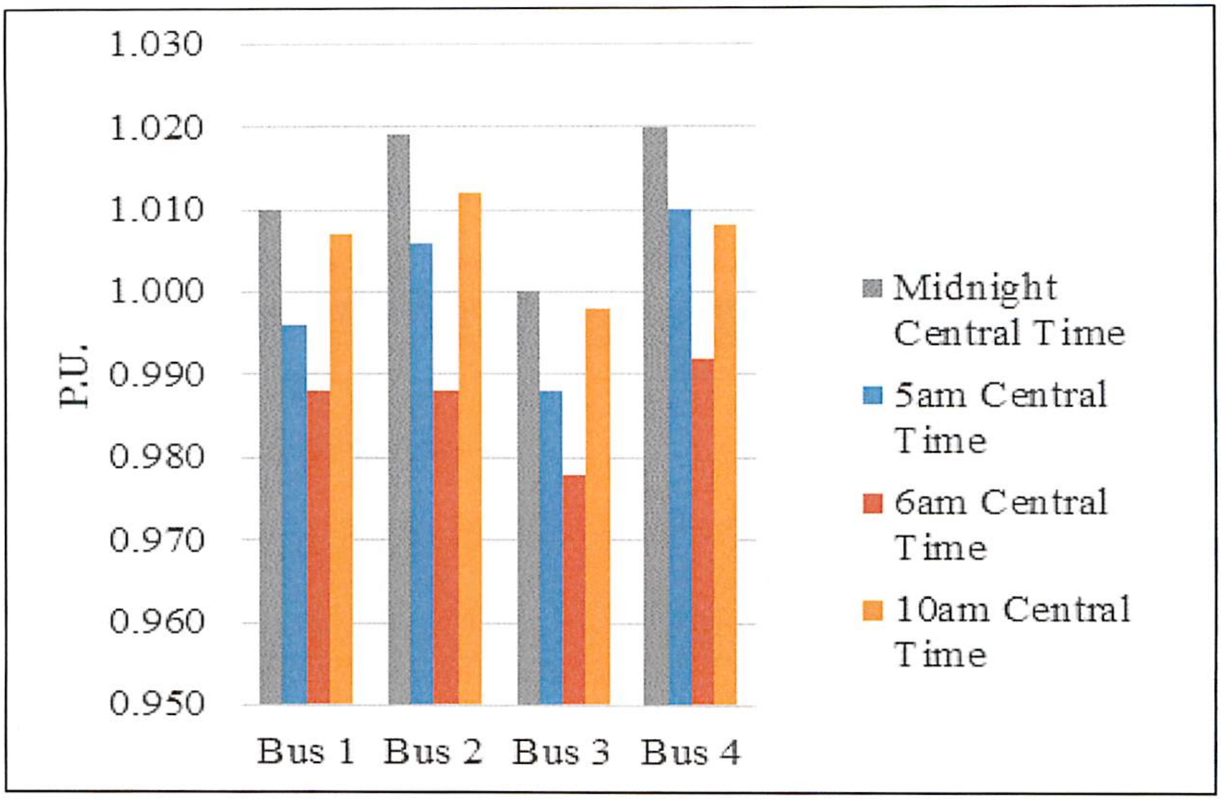
[96]https://cdn.misoenergy.org/2018%20IMM%20Quarterly%20Report%20Winter162312.pdf; Appendix I.

Figure 38: 10 am CST: Improvement in Southwestern-to-Southeastern Oklahoma 345 kV Per Unit Bus Voltages, Early Morning, January 17, 2018



TVA BA declared a Power Supply Alert I in effect for its Balancing Authority area, and later declared EEA Level 1, which it exited by 1 p.m. TVA BA experienced its winter peak load on January 18, one day later than MISO and SPP, as the cold front moved northeast.

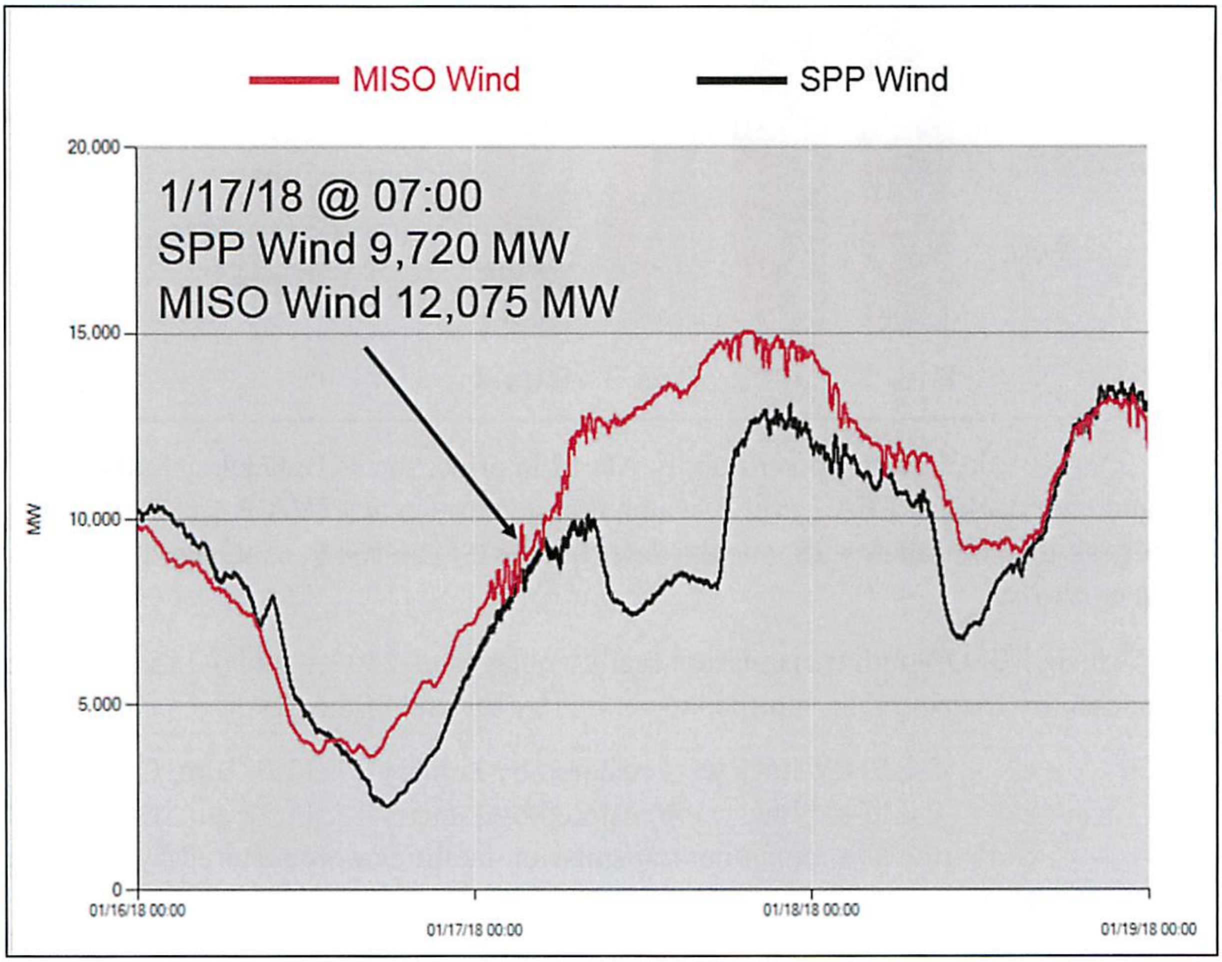
All six MISO South transmission facility outages (3-230 kV and 3-115 kV), which were caused by freezing rain, returned to service by the end of the day:

- 2-230 kV lines were restored by January 17, 11:07 a.m. CST,
- 2-115 kV lines were restored by January 17, 11:18 a.m. CST, and
- the two remaining transmission facilities were restored by 11:46p.m. CST.

Post-contingency overload conditions began to shift further east as the cold front moved, occurring more in Missouri, Tennessee and eastern Mississippi. However, many pre- and post-contingency measures already taken remained in effect in SPP, MISO and TVA RC. As new constraints occurred, the RCs coordinated well to manage system conditions. SPP developed post-contingent load-shed plans at four facilities in Oklahoma and Louisiana, as well as plans for post-contingent redispatch coordinated among SPP and TVA. MISO and TVA RC took mitigation actions via transmission reconfiguration in Mississippi to alleviate a real-time overload as well as a simulated severe post-contingency condition.

MISO's wind generation output continued to rise, reaching a record peak of 15,038 MW on January 17.[97] SPP's wind generation output decreased significantly just after the morning peak load, from 10,000 MW to 8,000 MW, and remained at around 8,000 MW until just before evening peak, when it sharply increased to almost 13,000 MW (95% of its all-time peak wind generation output), and remained at that output the remainder of January 17.

Figure 39: MISO and SPP Wind Output, January 16 Through 19, 2018



[97] MISO's previous wind generation peak of 14,683 MW was set in December, 2017. The January 2018 record was broken in March 2019, with 16,317 MW of peak wind generation output.

VI. Post-Event Actions by the RCs and Joint Parties

A. RTOC Meetings and Entities' Report

On March 15, 2018, MISO, SPP, TVA and SeRC met to discuss the event, lessons learned and ways to increase coordination among the four Reliability Coordinators.[98] The Regional Transfer Operating Committee (RTOC), a six-member committee which includes two members each for MISO, SPP and the Joint Parties,[99] met at least three times before providing a report to the Team in September, 2018, and continued to work on action items identified in the September report.[100] Among the action items identified by the RTOC were four aspects of improving coordination as to the RDT, which ultimately culminated in a new RDT procedure, as well as a written "statement of understanding" about interim and long-term methods of addressing RDT-impacted flowgates, as discussed in section C, below.

B. FERC Tariff Change on Deliverability of Reserves[101]

On April 27, 2018, MISO filed proposed revisions to its Tariff to authorize the application of the Tariff's reserve procurement enhancement provisions to the Sub-

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[98] Although the Regional Transfer Operations Procedure in place during the Event, RTO-RTOA-OP1-r0, provided for a formal "Operations Review" upon request by one of the RCs under circumstances including when an increase in the RDTL had been requested (section 3.4), the Joint Parties did not characterize their report as resulting from a formal "Operations Review," but it accomplished the purpose of analyzing the event and agreeing on next steps. The RTOC's post-event analysis, "Regional Transfer Operating Committee Event Review Report (September 9, 2018)," is included as Appendix I.

[99] The Joint Parties include AECI, LG&E/KU, PowerSouth, Southern Co. and TVA.

[100] See Appendix I.

[101] Prior to the Event, MISO had initiated the Resource Availability and Need (RAN) initiative, a broad analysis and plan to confront the increase in Maximum Generation emergencies even though sufficient capacity appeared to be available through the Planning Reserve Auction. The RAN initiative has led to several filings, including some of the filings described below, aimed at improving capacity availability in all seasons.

Regional Power Balance Constraints (MISO's internal name for the RDTL). The Commission accepted MISO's filing, effective August 26, 2018.[102] MISO supported its filing by stating that the "reserve procurement enhancement" provisions were designed to address certain problems arising from the fact that the deliverability of reserves was not fully addressed by its Tariff's then-existing approach to the setting of zonal reserve requirements. However, the original reserve procurement enhancements applied only to transmission constraints and did not apply to Sub-Regional Power Balance Constraints, which are contractual in nature. MISO contended that the contractual nature of Sub-Regional Power Balance Constraints should not preclude the application of the reserve procurement enhancement. MISO asserted that the revisions it proposed will enable it to use reserve procurement to manage flows, including post reserve deployment flows, between MISO Midwest and MISO South in accordance with the RDTL.

C. Revised Regional Transfer Operations Procedure and RDT-Impacted Flowgate Statement of Understanding

In December, 2018, a new version 2.0 of the Regional Transfer Operations Procedure (RTOP), which implements the Settlement among the Joint Parties, became effective. This version "incorporate[es] January 17, 2018 Lessons Learned" according to the Revision History, and, like the earlier version, is approved by MISO, SPP, TVA and SeRC. The revised version improves on the original in the following ways:

- Requiring MISO to ensure that both UDS and real-time RDT remain at or below the RDTL (versus only UDS during the Event).[103]
- Requiring MISO to provide forecasts of the RDT to SPP, TVA, and SeRC.[104] and share key information which could affect the RDT for rolling 5 days into the future.[105]

[102] *Midcontinent Independent System Operator, Inc.*, 164 FERC ¶ 61,129 (2018). On March 15, 2019, MISO submitted revisions to conform additional provisions with recently accepted Tariff changes on the consideration of Post Reserve Deployment Constraints, including Sub-Regional Power Balance Constraints.

[103] 3.1.3.

[104] 3.1.4.

[105] 3.1.4.2.

- Identifying criteria for determining RDT-impacted flowgates [106]
- More specific actions to be taken to address congestion and RDTL exceedances, [107] including an ordering of congestion management procedures and a new subsection on potential load shed conditions. [108]

To implement the identification of RDT-impacted flowgates, [109] MISO, SPP and the Joint Parties agreed to a two-step process for performing the necessary calculations for determining RDT-impacted flowgates. The interim step is required because as intra-market flow, MISO's RDT flow is not currently input into the Interchange Distribution Calculator (IDC) used to implement TLRs, but integrating the RDT flow into the IDC is planned for the second phase.

D. Additional MISO Tariff Revisions Relevant Post- Event

MISO has been studying the issue of capacity resources that are not available during periods when the system is under stress, particularly in non-summer periods and particularly in MISO South. Prior to the Event, MISO started a process known as the Resource Availability and Need Initiative. Some of the early fruits of the Initiative are tariff changes to better insure capacity availability, as described below.

On February 19, 2019, the Commission accepted MISO's Tariff revisions that now require LMR resources that become capacity resources to identify the period of the year that they are available and the notification time they require for deployment. This must include the four summer months with a notification time of no more than12 hours. The resource must be able to justify the availability it identifies. On March 29, 2019, the Commission accepted, subject to condition, MISO's Tariff revisions [110] that were intended to supplement the existing Generator Planned Outage process by improving transparency through forward signals and incentives. [111] MISO's revisions, which included a penalty for planned outages and derates that occur during Max Generation events, were intended to: (1) provide additional incentives for Generator Owners to

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[106] 3.1.5.

[107] 3.1.6, 3.2 and 3.3.

[108] 3.3.8.

[109] As discussed in section 3.1.5 of the RTOP.

[110] Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

[111] Midcontinent Independent System Operator Inc., 166 FERC ¶ 61,236 (2019).

schedule Generator Planned Outages and derates well in advance of the scheduled start time and (2) identify times with increased system risk due to correlation of outages and derates. The Commission agreed with MISO's efforts to enhance its Generator Planned Outage scheduling practices, believing that MISO's proposal will "promote advanced scheduling of Generator Planned Outages, improve Generator Planned Outage coordination, and help MISO address the recent increase in the number of declared Emergency events during non-summer seasons."[112]

The same day, the Commission accepted, subject to condition, MISO's proposal to enhance the testing requirements in its Tariff for resources that participate in MISO's markets as LMRs.[113] The Commission agreed with MISO's efforts to ensure that the LMRs it relies upon can in fact supply their registered load- reduction capability during emergency events. The Commission found it necessary for MISO to have confidence that LMRs will perform when scheduled, and stated that it expects MISO's proposed testing requirements to enhance LMR performance.

VII. Prior Similar Events

2011 Southwest Cold Weather Event of February 5-11, 2011[114]

This event, which affected the southwest region of the United States (Texas and New Mexico) during the first week of February, 2011, was similar to the Event in that extreme low temperatures caused widespread generation outages. In the 2011 cold weather event, many cities in Texas and New Mexico experienced a 50 degree drop in temperature. The cold temperature conditions in 2011 were similar to what was found for the Event, where many south central cities experienced a 40-50 degree drop in temperature over a several-day period: daytime high temperatures in the 60s to low-70s on Friday, January 11, in cities such as Little Rock, Texarkana, Shreveport, Jackson, Beaumont, Baton Rouge and New Orleans, dropped to daytime highs in the high teens to upper 20s on January 17. In both events, many generators did not winterize to protect against freezing weather conditions, despite recommendations from the 2011 report to do so. In both events, massive generation outages and derates led to energy emergencies,

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[112] Id. at P. 60.

[113] Midcontinent Independent System Operator Inc., 166 FERC ¶ 61,235 (2019). See fn. 14 for more information about LMRs.

[114] Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations, found at https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

however, in the 2011 event, the RC needed to perform controlled load shedding to maintain system reliability, whereas in the Event, emergency energy purchases and LMRs, among other tools, allowed the RCs to avoid shedding firm load (although firm load shedding could have occurred if the MISO South WSC occurred).

<u>2014 Polar Vortex</u>[115]

The Polar Vortex event of early January, 2014, which affected the Midwest, South- central, and East Coast regions, similarly involved significant unplanned generation outages and derates, Both the Polar Vortex and the 2011 event were similar to January 17, 2018, in that generation reserves were depleted within the event areas, due to significant unplanned generation outages and derates, requiring energy emergency measures ranging from voluntary load reduction to interruptible load shed to rotating blackouts/firm load shedding.

<u>Cold Wave of 1994</u>[116]

A complicating characteristic of the Event not found in the Polar Vortex or 2011 events was wide-area constrained BES conditions, stretching across four RC footprints. The Cold Wave that occurred the week of January 16, 1994, in the Midwest and Mid-Atlantic states, also had wide-area constrained conditions combined with capacity/reserves shortfalls, similar to the Event. Faced with unusually high electricity demands, and cold weather-related generator outages and reduced fuel supply, utilities with generation shortages imported large blocks of power over their transmission systems from other utilities. System operators managed several transmission paths near their post-contingency transfer limits, to ensure reliability while the large power transfers occurred, although some localized voluntary load shedding occurred.

<u>Could This Happen Again?</u>

The Event, combined with the other events, reaffirms the importance of generators remaining in operation during extreme cold weather conditions, to support reliable BES operations. More recently, MISO and SPP generators performed better in the January 30-31, 2019 Polar Vortex which affected the Midwest. Unlike facilities in warmer climates such as the south central U.S., generating stations in the colder Midwest are typically

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[115] NERC report on 2014 Polar Vortex, https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[116] NERC report on Electric Utilities' Response to the Cold Wave of January, 1994.

designed and constructed so that their boilers, turbines, and other auxiliary systems are not exposed to ambient weather conditions.[117] Unusually cold temperatures in warmer-weather areas, combined with a lack of generator preparation for conditions expected, could again lead to substantial unplanned generation outages, with similar effects on reserves and potentially, BES conditions.

VIII. Findings and Recommendations

Generator Cold Weather Reliability

Finding: The South Central U.S. Cold Weather BES Event of January 17, 2018 was caused by failure to properly prepare or "winterize" the generation facilities for cold temperatures.

- A comparison of below-freezing temperatures in the Event Area and unplanned generation outages and derates from January 15 through 19 resulted in three cities with correlation coefficients[118] of -0.7 or better, and the majority of cities with coefficients of between -0.5 to -0.7, indicating that as temperatures decreased, unplanned outages and derates increased.
- At least 44% of the unplanned outages or derates during January 15 to 19 were directly attributed to, or likely related to, the extreme cold weather, as calculated by numbers of units. Fourteen percent of the generator failures were directly attributed by the Generator Owners/Operators to weather-related causes, including frozen sensing lines, frozen equipment, frozen water lines, frozen valves, blade icing, low temperature cutoff limits, and the like. Another 30 percent were indirectly attributable to the weather (occasioned by natural gas curtailments to gas-fired generators (16%) and attributed to mechanical causes known to be related to cold weather (14%)).[119]

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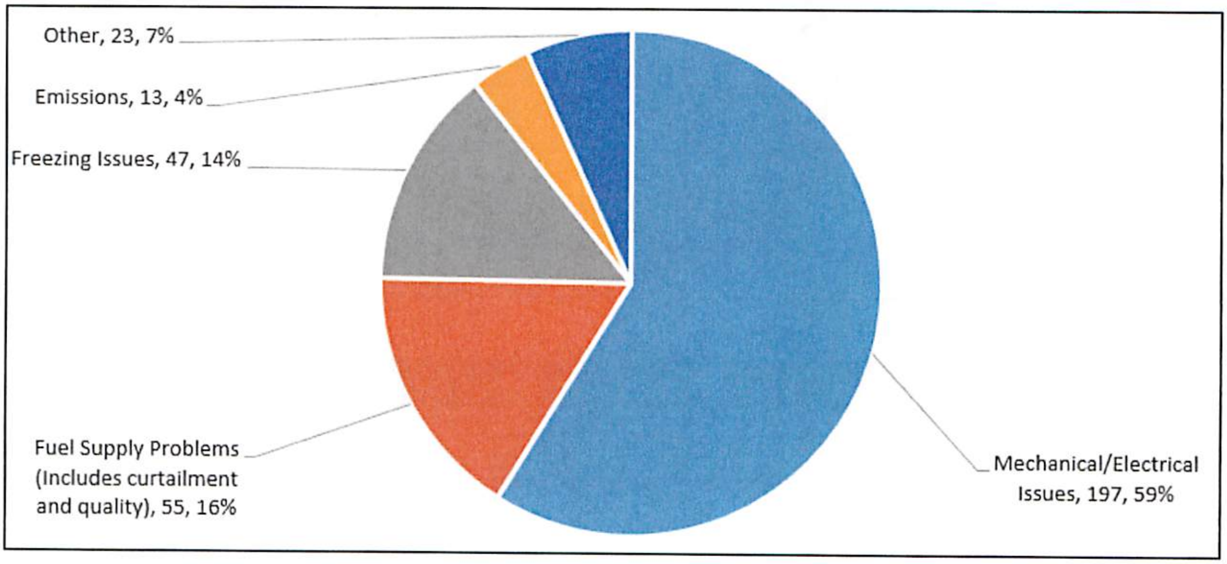
[117] 2011 Southwest Cold Weather Event FERC/NERC Report, Appendix: Power plant design for ambient design temperatures at page 142.

[118] A correlation coefficient is a number or function that indicates the degree of correlation between two sets of data or between two random variables and that is equal to their covariance divided by the product of their standard deviations. (Source: Merriam-Webster Dictionary.) A negative correlation coefficient indicates that as one variable increases, the other decreases, and vice-versa. In this case, the negative correlation meant that as temperatures decreased, generation outages increased.

[119] These causes included issues with specific equipment known to be vulnerable to freezing, including drum level transmitter sensor lines, inlet guide vanes, gas purge valves, steam turbine intercept valves and other valves; issues related to cold oil, such as

- Unplanned generation outages and derates during the period of extreme cold accumulated to approximately 14,000 MW in the Event Area by the morning peak hour ending 8 am CST on January 17, 2018.
- Generator Owners attributed at least 35% of the generation outages and derates on January 17, 2018 to the extreme weather conditions: 19% to freezing-related mechanical issues and 16% to cold-related fuel supply issues.[120]

Figure 40: **January 15-19, 2018 - Causes of Unplanned Generation Outages and Derates for Event Area**



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oil pressure drop or failure to start; wet/frozen coal causing problems with feeders or conveyors; and loss of feedwater.

[120] More than 35% of the generator outages and derates on January 17 were likely related to the extreme cold. The Team found that for January 15 through 19, 14% of the outages and derates attributed to mechanical causes were actually caused by issues known to be related to cold weather. The Team did not perform this analysis for January 17 alone.

Figure 41: January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area

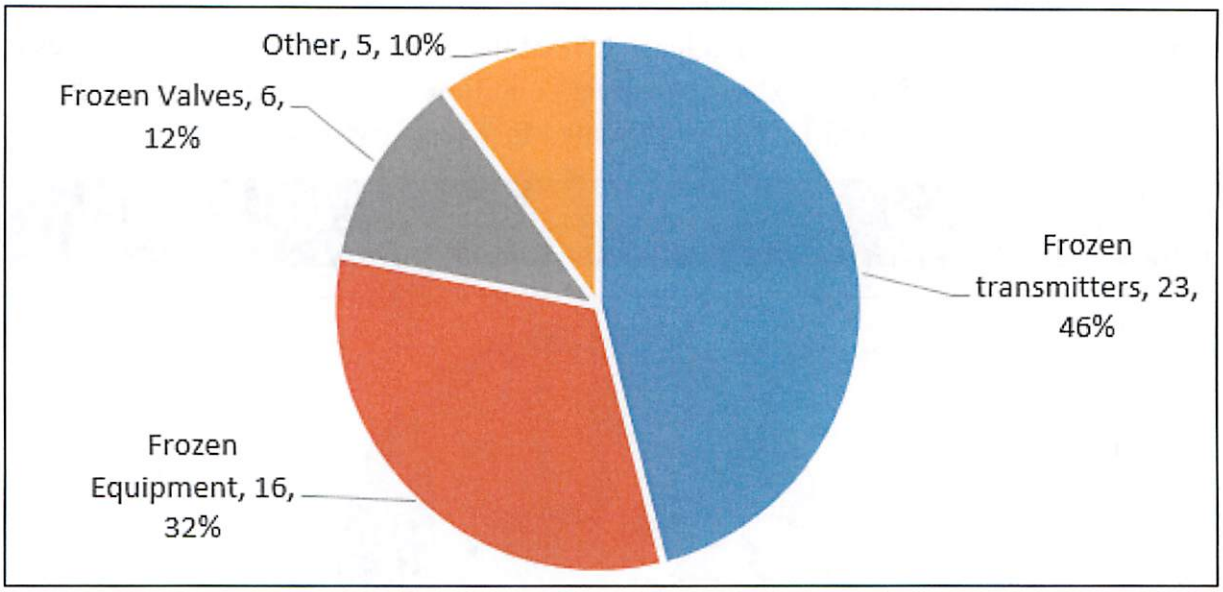


Figure 42: January 17, 2018 - Causes of Generation Outages for Event Area, By RC

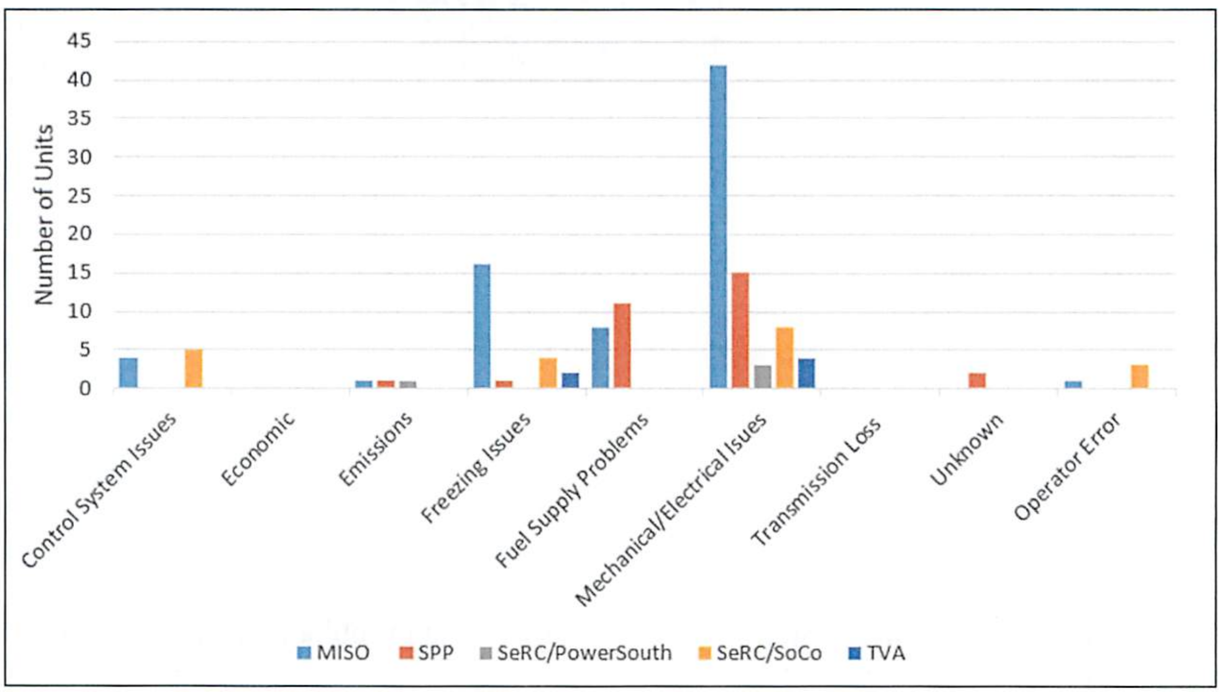


Figure 43: **January 17, 2018 – Causes of Unplanned Generation Outages and Derates for Event Area**

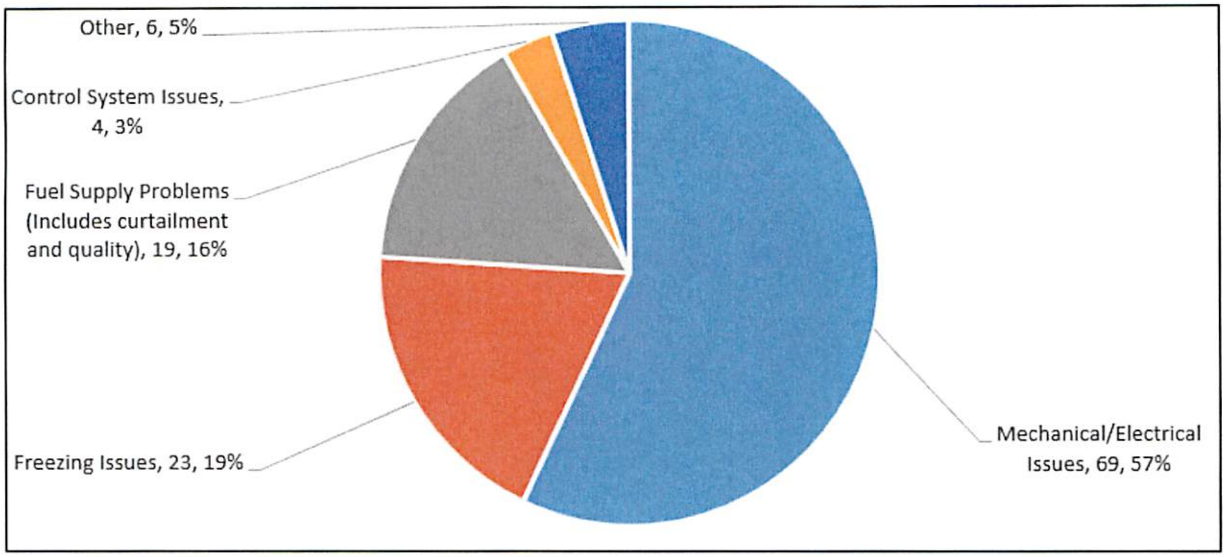


Figure 44: **January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area**

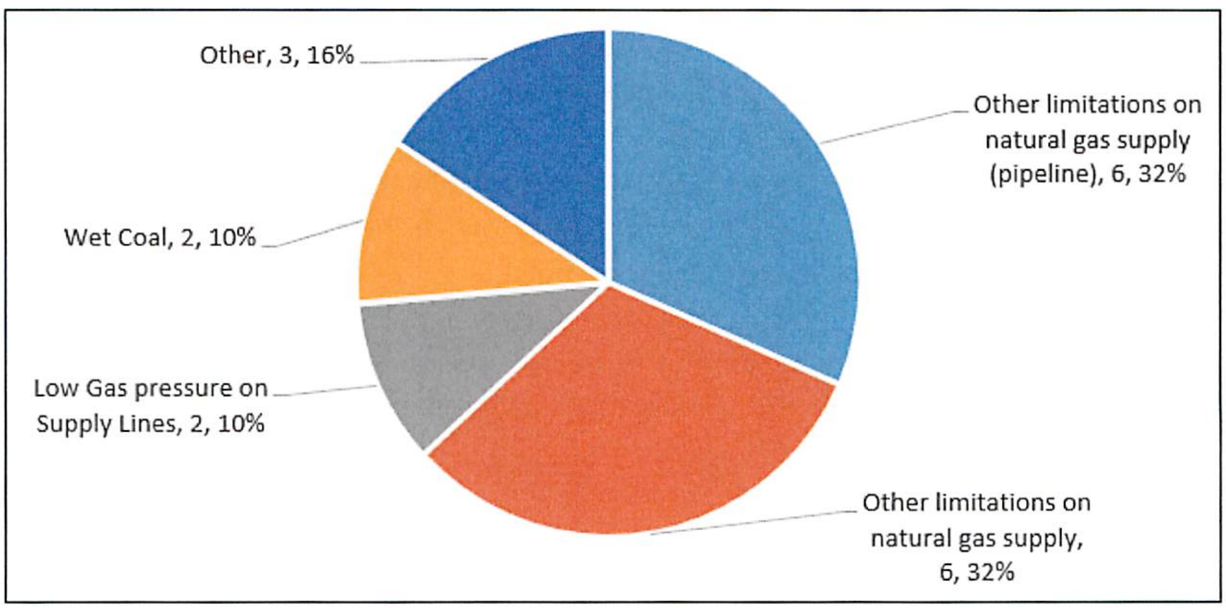
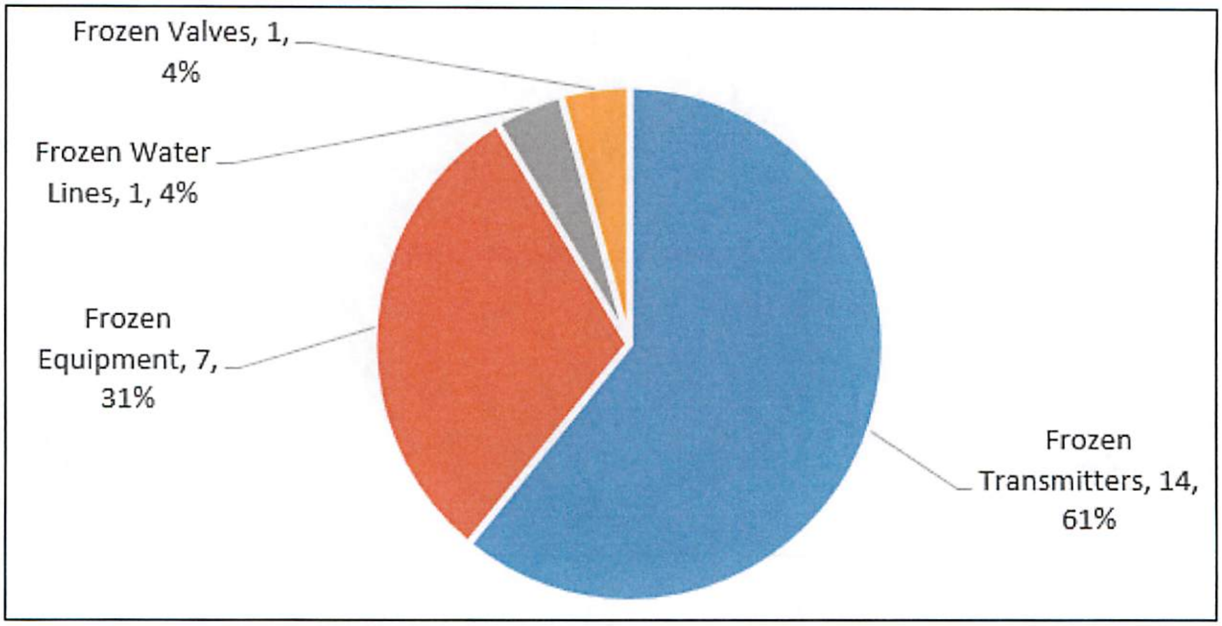


Figure 45: January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area



Finding: Gas supply issues contributed to the Event, and natural gas-fired units represented at least 70% of the unplanned generation outages and derates.

- From January 15 to 19 in the Event Area, natural gas-fired units were 70% of the unplanned generation outages and derates when calculated by numbers of units, and 74% when calculated by MW.
- During the same period, gas supply issues caused by the extreme cold temperatures, including interruptible supply, low gas pressure, and other pipeline and gas supply issues, led to outages of 38 units, for a total of approximately 2,200 MW.
- The Team found that temperatures in the Event Area were generally above the ambient temperature design specifications[121] for many natural gas-fired generating units.

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[121] Most of the units in the Event Area have an ambient temperature design rating between -10 and 10 degrees, with some exceptions. A handful of units have an ambient temperature design rating to -20 degrees, and four units are rated for use to -40 degrees. Some entities did not incorporate (or did not know) their units' ambient temperature design ratings.

Figure 46: **January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area**

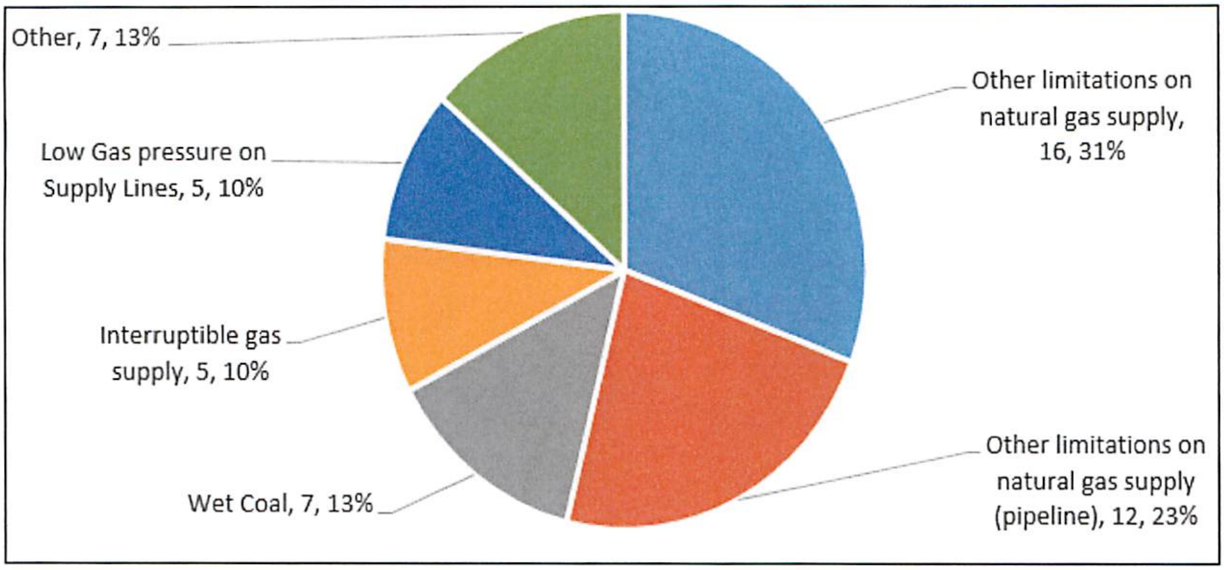


Figure 47: **January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by Number of Generators)**

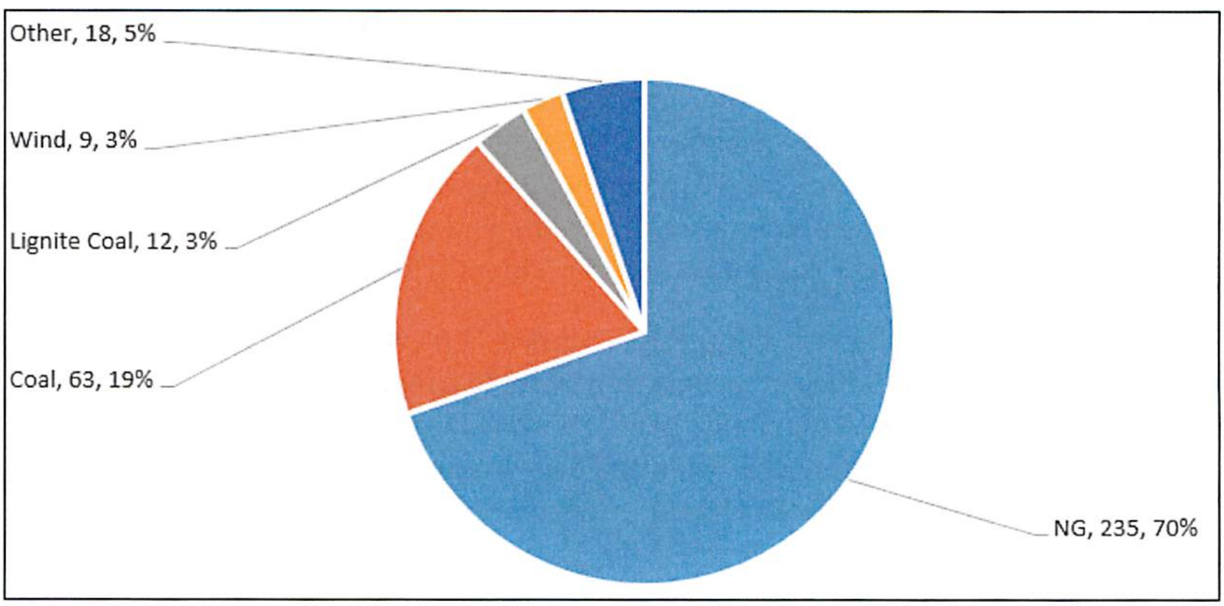
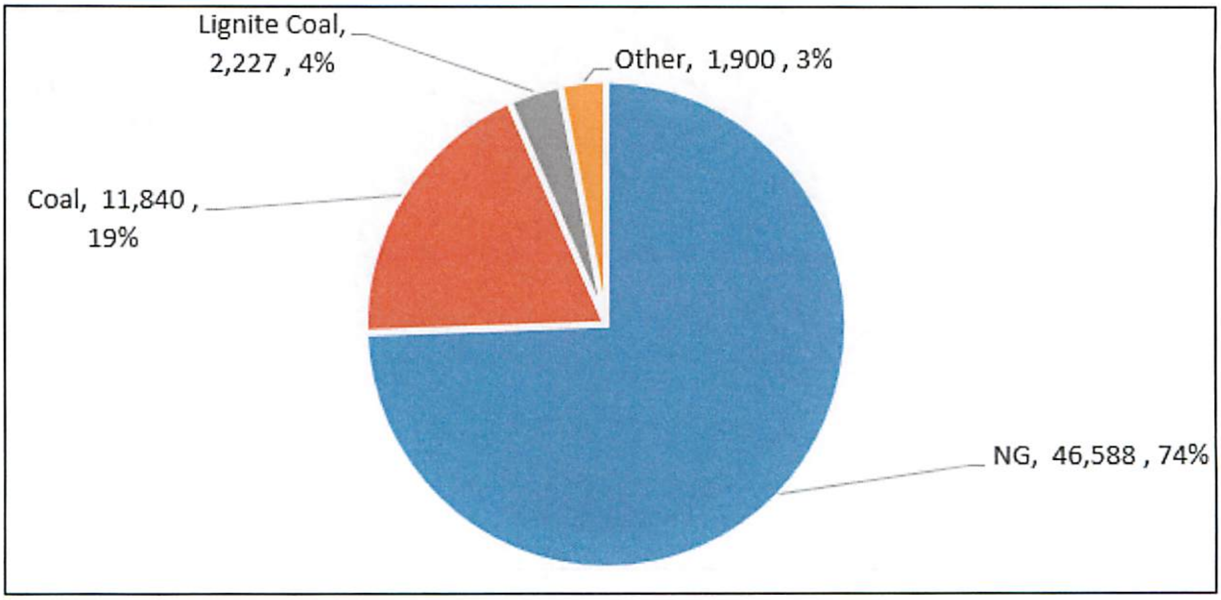


Figure 48: **January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by MW of Generation)**



Generator Cold Weather Reliability

Recommendation 1: The Team recommends a three-pronged approach to ensure Generator Owners/Generator Operators, Reliability Coordinators and Balancing Authorities prepare for cold weather conditions: 1) development or enhancement of one or more NERC Reliability Standards, 2) enhanced outreach to Generator Owners/Generator Operators, and 3) market (Independent System Operators/Regional Transmission Organizations) rules where appropriate. This three-pronged approach[122] should be used to address the following needs:

- **The need for Generator Owners/Generator Operators to perform winterization activities on generating units to prepare for adverse cold weather, in order to maximize generator output and availability for BES reliability during these conditions. These preparations for cold weather should include Generator Owners/Generator Operators:**

[122] While any one of the three approaches may provide significant benefits in solving this problem, the Team does not view any one of the three as the only solution. The Team envisions that a successful resolution of the problem will likely involve concurrent use of all three.

- **Implementing freeze protection measures and technologies (e.g., installing adequate wind breaks on generating units where necessary).**
- **Performing periodic adequate maintenance and inspection of freeze protection elements (e.g., generating units' heat tracing equipment and thermal insulation).**
- **If gas-fueled generating units, clearly informing their Reliability Coordinators and Balancing Authorities whether they have firm transportation capacity for natural gas supply**
- **Conducting winter-specific and plant-specific operator awareness training.**

- **The need for Generator Owners/Operators to ensure accuracy of their generating units' ambient temperature design specifications.[123] The accurate ambient temperature design specifications and expected generating unit performance, including for peak winter conditions, should be incorporated into the plans, procedures and training for operating generating units, and shared with Reliability Coordinators and Balancing Authorities.**

- **The need for Balancing Authorities and Reliability Coordinators to be aware of specific generating units' limitations, such as ambient temperatures beyond which they cannot be expected to perform or lack of firm gas transportation, and take such limitations into account in their operating processes to determine contingency reserves, and in performing operational planning analyses, respectively.**

Staff analysis of the outages between January 15 and 19 found that of 183 total units affected, the Generator Owners/Operators directly attributed 16% to freezing, and 14% to fuel supply issues related to the extreme cold. An additional 14% were likely caused by the extreme weather conditions. Outages in this last subcategory had been placed in the "mechanical/ electrical failures" category (59% of the outages between January 15 and 19) by the Generator Owner/Operators, but based on more detailed information, were found to be caused by problems known from earlier cold-weather events to be associated with extreme cold. Adding the categories directly attributed to and likely related to the extreme cold (16% plus 14% plus 14%) results in 44% of the total outages being directly or likely related to cold. Inquiry Staff also found that the total generation outages for January 15 through 19 (including all categories and subcategories)

[123] The Team found that temperatures were generally above the ambient temperature design specifications for many natural gas-fired generating units (See fn 121).

were statistically correlated with temperatures, with a -0.7 correlation overall. One-third of the GO/GOP entities surveyed had no winterization provisions.

These findings echo those from the Joint FERC-NERC Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011 and the NERC 2014 Polar Vortex Report, both of which found that many generators failed to adequately prepare for winter weather conditions.

One of the recommendations from the 2011 Southwest Cold Weather Event was to create a mandatory winterization Reliability Standard. In September, 2012, NERC submitted a Standard Authorization Request (SAR) which proposed to require Generator Owner/Operators to:

- report generating unit capabilities based on anticipated winter weather using criteria developed by the standard drafting team using stakeholder input.
- ensure winter weather preparation plans are created, maintained, implemented and monitored as appropriate to help ensure generating units can operate to the criteria developed above. The plans shall include appropriate annual winterization measures.

When NERC's Operating Committee proposed a voluntary Reliability Guideline titled Generating Unit Winter Readiness, instead of a mandatory Reliability Standard, the Standards Committee rejected the SAR.[124]

In addition to the recommendations made in the 2011 Southwest Cold Weather Event and the 2014 Polar Vortex Reports on winter preparedness, and NERC's Reliability Guideline, other voluntary steps have been taken since 2011, including:

- NERC video on "Winter Weather Preparedness"
- NERC webinar on "Winter Preparation for Severe Weather Events"
- Numerous NERC "Lessons Learned" documents issued pertaining to winter weather preparedness

[124] The rejection was also based on industry comments and a recommendation from NERC's Reliability Issues Steering Committee. See NERC's July 2013 letter to the proponent of the SAR:

https://www.nerc.com/pa/Stand/Project%20201301%20Cold%20Weather%20Preparedness/SAR_Response_Letter_SM_071813.pdf For more information regarding the proposed SAR, see https://www.nerc.com/pa/Stand/Pages/Project2013-01_Cold_Weather.aspx

- NERC-developed training package on "Extreme Weather Events" posted for industry use,
- Gas and Electrical Operational Coordination Considerations Reliability Guideline developed by the NERC Operating Committee, and
- Regional Entities' cold-weather guidance (e.g. SERC's Cold Weather Preparedness efforts,[125] ReliabilityFirst's cold weather resources, including Winterization Visit Best Practices and Review of Winter Preparedness Following the Polar Vortex[126]).

However, despite the guidance above, cold-weather events continue to occur involving extensive unplanned generation outages, which imperil reliable BES operations. A mandatory Reliability Standard would require Generator Owner/Operators to properly prepare for extreme cold weather, and would help RCs and BAs identify units which may not be able to perform during an extreme weather event. However, the process from SAR to Commission approval of a mandatory Reliability Standard could take a year or more. In the meantime, enhanced outreach and actions by ISOs/RTOs to incent generator performance can also help to prevent a recurrence of the large-scale unplanned outages like those seen during the Event, the Polar Vortex and in ERCOT in 2011.

<u>**Situational Awareness and RC-to-RC Communication**</u>

<u>**Findings**</u>**:**

- **The Relevant RCs (MISO, SPP, TVA and SeRC) had situational awareness throughout the event and communicated as necessary to preserve system reliability.**
    - RCs were regularly performing real-time assessments to determine system state and next courses of action, including identifying operating limit exceedances and voltage conditions for both real-time and for simulated post-contingency conditions.
    - The RC operators communicated and coordinated their analyses and discussed mitigation actions necessary to maintain BES reliability, up to shedding firm load.
    - During the Event, the Joint Parties affected by transfers between MISO Midwest and MISO South, including the four RCs, had a written procedure, the Regional Transfer Operations Procedure, which covered their interactions as to MISO's Regional Directional Transfer.

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[125] www.serc1.org/coldweatherprep

[126] https://rfirst.org/KnowledgeCenter/Risk%20Analysis/ColdWeather

- After the Event, the Joint Parties implemented a revised Regional Transfer Operations Procedure, RTO-RTOA-OP1-r2.0, effective December 1, 2018.

- **The generation outages and derates on January 17 created energy emergency conditions which required voluntary load reduction and plans for firm load shed if MISO's 1,163 MW worst single contingency in MISO South occurred.**
  - MISO invoked energy emergency alerts and purchased emergency energy for MISO South due to stranded reserves within its BA footprint.
  - The system in the Event Area was severely capacity-constrained. Even after emergency purchases, MISO South's reserves were down to 172 MW for the hour ending 8 a.m. CST.
  - Constrained transmission conditions spanned a large area, across all or portions of nine states (Arkansas, Alabama, Kansas, Louisiana, Mississippi, Missouri, Oklahoma, Tennessee, and Texas), and four RC footprints (MISO, SPP, TVA and SeRC).
  - As the morning peak (7 to 8 a.m. CST) neared on January 17, for the MISO South WSC, it would have likely resulted in firm load shed across the MISO South region to maintain generation and load balance and prepare to meet the next worst single contingency, while simultaneously triggering further and additional firm load shed in specific areas of the MISO South footprint to maintain BES voltages within post-contingency limits.

Situational Awareness Recommendations:

Recommendation 2: Reliability Coordinators should perform real-time voltage stability analysis in addition to RTCA, for constrained conditions occurring within their own and/or within adjacent Reliability Coordinator areas, such as those experienced by MISO the morning of January 17, and communicate the results of their analysis to adjacent Reliability Coordinator areas. Constrained system conditions during the Event included: multiple generation outages and derates in MISO South, high system loads, large regional transfers due to stranded reserves, transmission outages in generation-limited load pockets, and limited additional transfer capability. On January 17 some of these conditions were also occurring simultaneously in neighboring Reliability Coordinator footprints. Real-time voltage stability analysis could assist Reliability Coordinators in determining if other mitigation actions are necessary as well as whether an emergency condition exists. If such stressed system conditions are projected for the next day, voltage stability analysis should also be performed as part of the Reliability Coordinators' Operational Planning Analyses.

Recommendation 3: To provide accurate results for the Reliability Coordinators' real-time tools, adjacent Reliability Coordinators should benchmark their planning and operations models to actual events, like the January 17 event that stressed both the Reliability Coordinator and its adjacent Reliability Coordinator(s), and correct any inconsistencies identified.

Recommendation 4: Reliability Coordinators should also perform periodic impact studies to determine which elements of their adjacent Reliability Coordinators' systems have the most impact (i.e., the effect an outaged element located in an adjacent Reliability Coordinator area has on its voltages, facility loadings, or other conditions) on their systems. Reliability Coordinators should consider adding any identified external facilities to their models and should share associated real-time external network data. Beyond the enhanced model incorporation into tools such as RTCA, these sensitivity studies could identify external facilities which have such an impact that the Reliability Coordinator may also implement real-time EMS alerting for the loss of the external facility.

Recommendation 5: Balancing Authorities and Transmission Operators should conduct periodic capacity and energy emergency drills simultaneous with transmission emergency drills with their Reliability Coordinators, to ensure readiness, coordination of control room personnel to conduct multiple load-shed-related tasks while continuing to maintain situational awareness, and coordination between additional local control center and field personnel. On January 17 during the peak hour, MISO system analysis showed that if its next-contingency generation outage in MISO South of 1,163 MW occurred, it would need to rely on post-contingency manual firm load shed to maintain voltages within limits, while faced with potential additional firm load shedding to maintain system balance and restore reserves for MISO South region. Operators may be required to perform additional tasks if the load shed must be executed within narrow boundaries (e.g. limited load shed options that will result in alleviating transmission overload and/or low voltage conditions), coupled with conditions (such as extreme temperatures), which create the need for rotational load shedding to protect life or health.

Had the MISO South WSC occurred during the morning peak hour of 7 to 8 a.m. CST, it would have required replacement generation from MISO Midwest, thereby further increasing RDT transmission flows into MISO South partly through parallel paths within SPP, TVA RC and SeRC footprints. Both MISO and SPP included the MISO South WSC as a contingency, both model each other's systems to an extent in their RTCA applications, and both showed their RTCA converging, which means that they did not expect instability or cascading as a result of the simulated outage of the 1,163 MW WSC.

However, MISO's RTCA projected a trend of post-contingency low voltage, including voltages as low as 88% on certain 230kV buses, and 24 transmission facilities with projected post-contingency thermal overloads between 7 and 8 a.m. CST. MISO operators relied on RTCA convergence, which indicates steady-state stability,[127] to assure that voltage stability could be maintained despite numerous post-contingent system conditions. Also, MISO relied on the TOPs within its footprint to quickly execute the necessary load shed if the MISO South WSC occurred, to alleviate numerous low voltages. This analysis would be especially important given that MISO recognizes that one of its load pockets is "a voltage/thermal sensitive area and is susceptible to low voltages under outage conditions or a loss of a key transmission element," and for MISO's WSC in MISO South of 1,163 MW, it would have likely resulted in the need for post-contingency load shedding steps to alleviate numerous transmission facilities from experiencing low voltage conditions, while faced with potential additional firm load shedding to maintain system balance and restore reserves for MISO South region.

RC-to-RC Communications Recommendations

Version 2.0 of the Regional Transfer Operations Procedure is an improvement on the Procedure in use during the Event. The Joint Parties should consider the following revisions that would further enhance RC communications:

Recommendation 6: Make the following changes to the Regional Transfer Operations Procedure:

- **Provide operators with more specificity for applying section 3.1.6.1 through 3.1.6.4 regarding how to return the Regional Directional Transfer to a level at or below the Regional Directional Transfer Limit within 30 minutes, and the relationship between 3.1.6.1 through 3.1.6.4 and 3.2 (congestion management). Also, clarify the roles and/or reference certain steps in the applicable emergency procedures that may assist the operators in taking prompt actions to return Regional Directional Transfer at or below the Regional Directional Transfer Limit.**
- **Clarify the relationship between 3.1.6.1 and 3.1.6.4 regarding calls to adjacent Reliability Coordinators and when the Reliability Coordinator operator will initiate reduction of the Regional Directional Transfer. Consider a timeline/flowchart of the sequence of communications, similar to the**

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[127] Capability of an electric power system to maintain its initial condition after small interruption or to reach a condition very close to the initial one when the disturbance is still present.

Transmission Loading Relief curtailment timing, found in the Joint NAESB System Operator's Transmission Loading Relief Reference Manual.

- **Clarify the section on "Potential Load Shed conditions" (section 3.3.8) to require the adjacent Reliability Coordinators to communicate an emergency condition if conditions in the Reliability Coordinator footprint so warrant. This change further aligns the procedure steps with the Reliability Standards.** [128]
- **Clarify that when making emergency energy purchases (for example, purchasing emergency energy, for meeting load plus reserves, or to alleviate Regional Directional Transfer flow before shedding load), Reliability Coordinator /Balancing Authority Operators should analyze the flow impacts prior to implementing the emergency energy schedule to avoid unintentionally causing detrimental impacts to Regional Directional Transfer -impacted flowgates or lead to an operating Emergency for Transmission Operator(s) area(s).**
- **In determining the need for temporary changes to the Regional Directional Transfer Limit (see 3.3.1) for the operating horizon/next-day analysis or during the operating day, MISO, in coordination with SPP and neighboring entities, should determine the maximum simultaneous transfer capability north-to-south (or south-to-north if applicable), based on the latest operating conditions expected during the timeframe for determination. This study should be used to support any decisions on making temporary changes to the Regional Directional Transfer Limit.**

Transmission Operations and Reserves

Findings: The generation outages during the peak hour ending 8 a.m. CST on January 17 created an "N-many" [129] **BES condition, and led the affected entities to transfer power from distant generation into the affected region to cover energy**

[128] Linking the obligation to shed firm load to the Reliability Standards will protect MISO if it needs to shed firm load to reduce the RDT. The RDT is a contractual limit rather than a limit imposed by one of the Commission-approved mandatory Reliability Standards (e.g. SOL, IROL). In the past, the Commission approved a penalty against a Balancing Authority/Transmission Operator that shed firm load when the load shedding was not required by a Reliability Standard. *See In re California System Operator Corporation*, 141 FERC ¶ 61,209 (2012)).

[129] That is, a large number of generation contingencies had occurred (generation units experienced unplanned outages, derates or failures to start).

demands and provide reserves. These large power transfers resulted in wide-area BES transmission-constrained conditions in four RC footprints.

- On a seasonal basis, both MISO and SPP separately performed assessments for the 2017/18 winter and shared their results; however, these assessments neither analyzed simultaneous power flows and transfers like those seen on January 17, nor quantified results of their combined impact.
- On a seasonal basis, MISO had predicted that it could transfer up to 4,650 MW in a north-to-south direction, but this analysis was based on less-severe transfer conditions.
- The transmission system conditions observed on the morning of January 17, 2018, were not solely due to MISO's north-to-south regional directional power transfer (RDT) flow to cover the supply shortfall caused by unplanned generation outages and derates MISO South, but to a combination of the RDT flow and additional factors including generation outages and derates in the rest of the Event Area (e.g., southeastern SPP footprint), high system loads related to extreme low temperatures in the Event Area, higher-than-forecast wind generation power transfers in MISO and SPP, and DC power transfer flows between SPP and the ERCOT Interconnection.
- To address the constrained system conditions, RC operators needed to consult with their TOP operators to verify system operating limits to aid in determining potential mitigation measures, and some RCs opened transmission facilities based on SOLs which did not reflect winter cold weather conditions.
- Although the Event Area normally has generous reserves (i.e., greater-than-20% projected reserve margins for winter peak conditions), the unplanned generation outages and derates created stranded reserves from the distant generation, especially in MISO South.
- In its next-day forward reliability assessment commitment, as well as during the January 17 event operating day, MISO utilized its full 3,000 MW RDT to aid in providing reserves for its MISO South firm load.

<u>**Seasonal Studies Recommendations:**</u>

<u>Recommendation 7</u>: Planning Coordinators and Transmission Planners should jointly develop and study more-extreme condition scenarios to be better prepared for seasonal extreme conditions. Examples of more-extreme condition modeling include:

- **removing generation units entirely to represent actual generation outages (especially outages known to occur during severe weather), versus scaling of generating unit outputs;**
- **modeling system loads so that the study accurately tests the system for the extreme conditions being studied; and**
- **modeling and studying actual extreme events experienced in the Planning Coordinator area and actual severe scenarios experienced in other Planning Coordinator areas.**

Results of these more-extreme condition studies should then be shared with operations staff for training purposes, and to aid in their planning for days where more extreme transfers are expected.

<u>Recommendation 8</u>: MISO and SPP should jointly perform seasonal transfer studies and sensitivity analyses in which MISO and SPP model same-direction simultaneous transfers (e.g. north to south, south to north, west to east) to determine constrained facilities so that they can develop mitigation plans or other procedures for the operators. Such studies should include, but not be limited to:

- **intra-market power transfers, without offsetting transfers in a way that would reduce the impact on determining constrained facilities;**
- **transfers of wind generation output to load areas using near-peak wind generation levels;**
- **simultaneous generation outages in adjacent Reliability Coordinator footprints (e.g. MISO South and southern SPP footprints); and**
- **increasing simultaneous transfers to levels that constraints cannot be fully alleviated.**

System impacts of the modeled transfers in the studies could vary based on which generators are removed. Sensitivity study cases should be performed for example, to produce a potential range of transfer capabilities based on varying generation outage scenarios.

For its Winter 2017-2018 Coordinated Seasonal transmission Assessment, MISO performed transfer studies which included studying MISO Midwest to MISO South intra-Balancing Authority area transfers to determine First-Contingency Incremental Transfer Capabilities for both north-to-south and south-to-north transfers. The maximum power transfer projected was 4,650 MW in a north-to-south direction, and MISO concluded this was adequate for the upcoming 2017-2018 winter season. However, the reported maximum power transfer value was based on less-severe power transfer conditions, since MISO modeled the power transfer by scaling generation between the internal north and south regions for the simulation of the transfer, versus modeling certain generators offline in MISO South in the study case to yield a transfer capability based on more extreme event conditions. This scaling of generation between the internal north and south regions for the simulation of the transfer did not entirely represent the effects on the power grid that outages of actual generating units would cause, such as loss of voltage support.

Additionally, MISO did not model the simultaneous north-to-south transfers in adjacent RCs (transfers from locations where generation reserves were available to those in which generation outages and derates), as well as high system loads (i.e., in MISO South, and in the southeastern SPP footprint), which occurred on January 17. These simultaneous north-to-south parallel flows contributed to numerous BES post-contingency limit exceedances and lower than normal system voltages, necessitating many post-contingency mitigations to be ready for the next contingency. The MISO and SPP footprints combined cover the entire mid-section of the U.S., and weather patterns may simultaneously and similarly impact their real-time operations, as on January 17.

Loss of southern generation occurred in MISO as well as SPP, and the parallel impact of those flows resulted in lower-than-expected real-time RDT capability. The Team also found that the results of the studies were not used to inform/support MISO's operations staff to aid in management of the RDT (e.g., lowering or raising of the RDT) for the operations planning horizon. If MISO performed more-severe condition studies, operators could use the study results in planning for conditions where more extreme RDT transfers are forecast.

System Operating Limits Recommendation:

Recommendation 9: Transmission Owners and Transmission Operators, as part of establishing facility ratings and System Operating Limits, respectively,[130] should conduct analysis that delineates different summer and winter ratings, for both normal and emergency conditions. The established facility ratings and associated System Operating Limits should consider, at a minimum, ambient temperature conditions that would be expected during high summer load and high winter load conditions, respectively.[131] These ratings and limits should be provided to the Reliability Coordinator and other applicable entities for use in tools for operation,

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[130] See fn 89.

[131] Some entities may have, for example, a winter rating based on 32 degrees and a summer rating based on 95 degrees. Other entities may have temperature-dependent ratings, which would also be consistent with the recommendation. Care should be taken when implementing ratings and limits, to account for unseasonal weather, e.g.., warmer-than-normal winter days.

such as Energy Management System and Real-Time Contingency Analysis applications. [132]

EMS systems have the capability to promptly update transmission facility limits for system operators so that they have accurate limits that reflect the current ambient conditions. The Team found that certain overhead-line transmission limits used by system operators during the Event reflected summer season conditions instead of the ambient cold weather conditions experienced during the event. Generally, limits based on colder conditions would have allowed the use of a higher capacity rating. The Regional Transfer Operations Procedure, RTO-RTOA-OP1-r2.0, contemplates in 3.2.2.1 the use of dynamic and emergency ratings as the first step in congestion management, which assumes the existence of such ratings. During its inquiry, the Team observed constrained transmission facilities for which one static rating was used year-round (i.e., Summer Normal =Summer Emergency=Winter Normal=Winter Emergency) and some of which had ratings that were atypically much lower than typical overhead circuit ratings applied at the same voltage. The use of seasonal ratings or dynamic ratings could allow for greater capacity ratings, thereby potentially reducing congestion and potentially ameliorating system conditions during an emergency.

Reserves Recommendations:

Recommendation 10: Balancing Authorities should consider deliverability of reserves to avoid stranded reserves. [133]

Recommendation 11: When MISO Balancing Authority relies upon 3,000 MW of Regional Directional Transfer flows in determining total reserve levels for MISO South, it should remain mindful that, as the Commission noted, "any amount above 1,000 MW of the 3,000 MW north-to-south limit . . . [is] only available on a non-firm, as-available basis." [134] **MISO should notify the other Reliability Coordinators operating under the Regional Transfer Operations Procedure (SPP, TVA and SeRC) when it needs to rely on any amount of the non-firm, as-available, portion of the Regional Directional Transfer to meet its reserves, due to a capacity shortage in**

[132] The Transmission Operator may need to work with the Transmission Owner to obtain facility ratings which do not limit the Transmission Operator's ability to provide the recommended limits.

[133] See *Planning and Reserves* Recommendation No. 3, in Appendix G, 2011 Recommendations on Preparation for Cold-Weather Events.

[134] Midcontinent Independent System Operator, Inc., 164 FERC ¶ 61.129, at P 37 (2018).

MISO South, so that the Reliability Coordinator Operators can timely communicate and act if conditions in the other Reliability Coordinators' footprints are projected to limit Regional Directional Transfer flows.

By depending on the total RDT, which consisted of 1,000 MW firm transmission capacity plus 2,000 MW as-available non-firm transmission capacity, MISO ran the risk of curtailment of the "non-firm, as available" portion of the RDT to alleviate transmission overloads, which could result in stranded reserves along with the potential for firm load shed in the MISO South region. These risks could increase further if emergency energy is unavailable or not deliverable from neighboring resources to provide reserves due to RDT curtailment.

<u>Load Forecasting</u>

<u>Findings</u>: **MISO's 5- to 3-day out load forecasts for MISO South were significantly lower than the actual peak load on January 17, and less accurate than adjacent RCs' forecasts for the same period.**

- MISO South region's five-, four-, and three-day-ahead "mid-term" peak load forecast errors in forecasting the actual peak load on January 17, 2018 were significantly larger (approximately 18.9%/6,000 MW, 10.2%/3,250 MW, and 6.1%/1,900 MW low, respectively) than the other RCs relevant to this event.
- Other RCs' load forecasts within the Event Area were much more accurate (with error rates ranging from 5.6% lower to 3.0% higher than actual peak load for five-days-out, 4.6% lower to 4.8% higher than actual for four-days-out, and 2.8% lower to 4.0% higher than actual for three-days-out).

<u>**Recommendations:**</u>

<u>**Recommendation 12**</u>: **MISO should work with its entities serving load/Local Balancing Authorities in the MISO South footprint to ensure that accurate and realistic load forecasts are provided to MISO in the five-, four-, and three-day-ahead forecasts. The Local Balancing Authorities should incorporate actual historic temperatures and loads from the January 17 event and other cold weather events into their future forecasts to capture potential peak demands during severe cold weather events.**

<u>**Recommendation 13**</u>: **MISO should work with adjacent Reliability Coordinators to improve the accuracy of its mid-term peak load forecasts for impending extreme weather conditions. This includes:**

- **Sharing five-, four-, and three-day-ahead temperature forecasts with adjacent Reliability Coordinators for upcoming extreme weather operating day(s)**

forecast (e.g., much below or above normal temperature conditions), for regions within their footprints.

- **Identifying causes of any significant differences between forecasts.**
- **Re-forecast peak loads to reduce significant differences in forecast error for these timeframes.**
- **Incorporating actual historic temperatures and loads from atypical events like January 17, 2018, into future forecasts to capture potential peak demands during severe cold weather events.**

With improved forecasting accuracy during the five-, four-, and three-day-ahead timeframes, additional longer-lead-time actions, including additional Load Modifying Resources, could have been taken to be better prepared for the operating day of January 17, 2018.

A. Sound Practices

Sound practices are just that—practices applied by one or more of the entities involved in the Event, which went beyond the requirements set forth in the mandatory Reliability Standards. The Team did not make a determination that they were "best practices," but found them worthy of note.

Transmission Sound Practices

1) In evaluating next-day system conditions, and due to the time typically needed to start a generating unit, SeRC uses an "N-1-1 tool" for evaluating the need to commit additional generation resources to provide area reliability for voltage and/or thermal line flow problems. The N-1-1 tool will evaluate the outage of a generator as the first contingency (N-1), followed by the removal of a transmission element as a second contingency (N-1-1), to determine if additional online generation resources are needed to reliably operate.

2) Given that large power transfers within BAs[135] can impact neighboring systems, to improve reliable operation among neighboring BAs and RCs, MISO, SPP and the Joint Parties have established a method for identifying RDT-impacted flowgates based upon simulated power transfers, for:
    a. The planning horizon, to perform the appropriate prior outage coordination activities and development of operating guides

[135] These power transfers are not interchange schedules between BAs. Intra-market/intra-BA transfers like these may exist elsewhere in the country and MISO's experience may prove helpful to others.

b. Real-time operations, to calculate the impact of RDT on flowgates to determine amount of RDT flow decrease needed based on the congestion on the RDT-impacted flowgate.

3) Neighboring RC operators demonstrated sound communication and coordination in managing real-time transmission constraints during the January 17, 2018 event. Faced with managing increasing transfers of power from remote generation [136] to the south central U.S. to serve the record electricity demands, MISO operators contacted SPP operators offering and implementing generation redispatch actions to alleviate transmission constraints through their coordinated market-to-market process. Both RCs' operators communicated and coordinated these types of actions at numerous times during the early morning hours on January 17, which aided in reliable BES operation.

4) To improve reliable operation during generation emergencies, MISO modified the rules for its Load Modifying Resources. The modified rules include requiring an LMR within MISO's footprint to offer its capability based on actual capability in all seasons, and to deploy based on the shortest notification requirement that it can consistently meet. [137] Before the Event, some of MISO's LMRs had very long notification requirements that limited their usefulness during unexpected events like those of January 17.

5) To support reliable operations during extreme weather events such as the Event, SeRC employed what it called "dynamically rated" operating limits for transmission facilities based on the extremely cold weather, which effectively raised the limits allowing more power to reliably flow. Had static limits (year-round/summer limits) been used, it would have resulted in significant generation redispatch (detrimentally impacting BA contingency reserves), possible transmission reconfiguration, and/or TLRs.

Generation Sound Practices

1) Southern Company (in the SeRC footprint), performed numerous generator fuel switches, using alternative fuel sources to help prevent a fuel supply emergency.

[136] MISO and SPP wind generation provided one source of power supply to both footprints which suffered unplanned generation outages and derates.

[137] See 166 FERC 61,116, ER19-650-000.

Fuel-switching is especially important during cold weather. During extreme cold weather events, natural gas limitations can be predicted/expected to occur as residential and commercial gas heating needs compete with electric generation needs, and gas pipeline entities can be expected to limit pipeline use to sustain gas pressure throughout the cold weather demand.

2) Continuous monitoring of heat tracing systems complete with a display panel and indicator lights.

3) Inspection of heat tracing circuits, including power supplies, prior to winter.

4) Having regular, periodic operational checks of heat tracing circuits.

5) Annual update of winter preparation checklist, incorporating lessons learned from previous winter.

6) Completion of freeze protection-related maintenance prior to winter weather.

7) Increased operator rounds/increased staffing prior to, and during winter weather to check for proper operation of plant equipment susceptible to freezing conditions.

8) Addition of a "freeze protection operator," during adverse weather who is responsible for inspecting critical equipment, and ensuring appropriate protection is in place.

9) Firing of dual fuel units that have not fired on their secondary fuel source during the previous year, prior to a forecast cold weather event.

10) RTO or RC conducting a survey of GO/GOP to determine winter preparedness activities have been completed, and fuel switching testing has been performed.

11) Sharing lessons learned by GO/GOP from extreme events, including through the NERC Events Analysis lessons learned program, or through Regional processes.

12) Developing procedures and training for Generator Operators on when to call for fuel switchable resources.

13) Maintaining inventory of pre-arranged supplies and equipment for extreme weather events by Generator Owners and Operators.

14) Generator Owners and Operators conducting readiness drills on extreme weather preparation.

15) Generators connecting to multiple pipelines when possible to allow for obtaining gas supply during tight market conditions if one or more pipelines has operational issues or high utilization that forces cuts to interruptible supply.

16) Generators keeping close contact with natural gas pipeline companies during events to keep abreast of timely public postings of operational details such as operationally available capacity and unexpected outages, which allows generators to make more flexible and timely decisions.

Appendices

Appendix A: January 17, 2018 Cold Weather Inquiry Joint Team Members

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Appendix B: Primer on Electric Markets and Reliable Operations of the BES

To help ensure that the electric grid operates as reliably and efficiently as possible, Congress granted FERC jurisdiction over electric grid reliability through the enactment of the Energy Policy Act of 2005 (EPAct), by adding a new section to the Federal Power Act, 16 U.S.C. § 215. Pursuant to its EPAct authority, FERC certified the North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO) responsible for establishing mandatory Reliability Standards, which then must be approved by FERC. FERC also promulgated regulations, approved Regional Entities to serve as regional compliance authorities,[138] and approved over 100 NERC-proposed mandatory Reliability Standards. This jurisdiction and oversight over the grid's reliability by FERC and NERC is vital to assuring consistent and dependable access to electricity. NERC currently has 16 Reliability Coordinators (RC) in North America to ensure that the grid is run efficiently and reliably. These RCs cover wide areas, and have the operating tools and processes to do so, including the authority to prevent or mitigate emergency operating situations. Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Tennessee Valley Authority (TVA) and Southeastern RC (SeRC) all served as RCs in the Event Area, and MISO and SPP are also Regional Transmission Organizations and Independent System Operators.[139] In the United States, RTOs and ISOs (hereafter, we will use RTO to refer to both) plan, operate and administer wholesale markets for electricity. MISO and SPP are RTOs that serve much of the Event Area discussed in this report. These entities, which are regulated by FERC, manage markets for energy and related services, for specific regions of the country.

Ensuring reliable operation of the power grid is complex and requires constant analysis and assessment. This is true for two fundamental reasons: (1) it is difficult to economically store large quantities of electricity, so electricity must be produced the moment it is needed; and (2) because alternating current (AC) electricity flows freely along all available transmission paths through the path of least resistance, it must be constantly monitored to maintain electricity flows over transmission lines and voltages within appropriate limits. The power system therefore must be operated so that it is

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[138] The Regional Entities relevant to this event are ReliabilityFirst, Midwest Reliability Organization, and SERC Reliability Corporation.

[139] See Figure 4 in the body of the report for a map of the Event Area.

prepared for conditions that could occur, but have not happened yet.[140] Should an outage or reliability issue occur, system operators must act promptly to mitigate adverse conditions and remain within appropriate limits. For conditions severe enough that they could cause instability, uncontrolled separation or cascading outages, mitigation must occur within no more than 30 minutes. Equally vital to the continued operation of the grid is that it is restored to a condition where it can once again withstand the next-worst single contingency.

All of the RTOs operate both "day-ahead" and a "real-time" energy markets. In the day-ahead market, buyers and sellers schedule electricity production and consumption before the operating day, which produces a financially-binding schedule, the day-ahead generation resource unit commitment, for electricity production and consumption one day prior to the actual generation and use. This provides generators and electricity load-serving entities a forecast of their needs prior to the day's operations and enables system operators to prepare an Operating Plan Analysis for the next day..[141] To perform the day-ahead unit commitment, RTO operators look for the most economic generators to schedule to be online for each hour of the following day, taking into account factors such as a unit's minimum and maximum output levels, how quickly those levels can be adjusted and whether the unit has minimum time it must run once started, as well as operating costs. Operators need to take into account forecast electricity demand or load

[140] NERC's mandatory Reliability Standards require that the bulk-power system be operated so that it generally remains in reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly referred to as the "N-1 criterion." N-1 contingency planning allows entities to identify potential N-1 contingencies before they occur and to adopt mitigating measures, as necessary, to prevent instability, uncontrolled separation, or cascading. As FERC stated in Order No. 693 with regard to contingency planning, "a single contingency consists of a failure of a single element that faithfully duplicates what will happen in the actual system. Such an approach is necessary to ensure that planning will produce results that will enhance the reliability of that system. Thus, if the system is designed such that failure of a single element removes from service multiple elements in order to isolate the faulted element, then that is what should be simulated to assess system performance." *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 1716 (2007), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[141] See Appendix C, "RC and TOP Tools and Actions to Operate the BES in Real Time."

conditions for every hour of the next day, and other factors that could affect grid capabilities such as expected generation and transmission facility outages, any adverse weather conditions (e.g. severe heat or cold, precipitation, high winds), and line capacities. If the analysis suggests that optimal economic dispatch cannot be carried out reliably, more expensive generators may need to replace the cheaper generators to operate reliably.

The current operating day, or real-time market, begins with the Operating Plan Analysis, created with generators who bid into and were chosen in the day-ahead market. It then reconciles any differences between the day-ahead schedule and the real-time load, while taking into account real-time conditions such as forced or unplanned generation and transmission outages, as well as electricity flow limits on transmission lines and other criteria, such as voltage, for BES reliability.

RTOs also act as Reliability Coordinators and/or Transmission Operators, and may also act as Balancing Authorities, to oversee system reliability in their footprints.[142] These are three of the functions for which the entities responsible for operating the BES in a reliable manner can register with NERC. These registrations then guide which of the mandatory Reliability Standards the entity must follow. A single entity can conduct multiple reliability functions and therefore have multiple NERC registrations. The NERC functional entity types most relevant to this event are Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, Planning Coordinator, and Transmission Planner.

The Reliability Coordinator is responsible for overseeing transmission operations for the wide area of the interconnection that it oversees. Similar to the Transmission Operator, below, the Reliability Coordinator ensures the reliable real-time operation of transmission assets by performing OPAs and preparing Operating Plans, but the Reliability Coordinator has the "wide-area" view, beyond any individual Transmission Operator. In coordination with other Reliability Coordinators, the Reliability Coordinator maintains situational awareness beyond its own boundaries, to enable it to operate within its Interconnection Reliability Operating Limits (limits necessary to prevent system instability and cascading outages) and maintain reliability of its area. Like the Balancing Authority, below, the Reliability Coordinator ensures the generation-demand balance is maintained, but within the larger Reliability Coordinator Area, thereby ensuring that the Interconnection frequency remains within acceptable limits. The Reliability Coordinators for the Event Area include MISO, SPP, TVA and SeRC.

[142] See Appendix E, "Categories of NERC Registered Entities."

The Balancing Authority (BA) integrates resource plans ahead of time, contributes to the Interconnection frequency in real time, and maintains the balance of electricity resources (generation and interchange) and electricity demand or load within the Balancing Authority Area. SPP RC, TVA RC, and SeRC contain multiple Balancing Authority Areas.

Transmission Operator and Generator Operator

The Transmission Operator (TOP) ensures the real-time operating reliability of the transmission assets within its area. It has the authority to take actions to ensure the continued reliable operation of the Transmission Operator Area. Like the RC, it performs daily OPAs and prepares Operating Plans, but for its smaller TOP footprint. The TOP coordinates with neighboring BAs and TOPs, as well as RCs, for reliable operations. The TOP also develops contingency plans, operates within established System Operating Limits, and monitors operations of the transmission facilities within its area. The following TOPs, among others, were affected by this event: AECI, LG&E and KU Services Co., MISO (MISO is registered as Transmission Operator and Transmission Planner in the RF and SERC Regions), PowerSouth, Southern Company Transmission, and TVA.

The Generator Owner (GO) owns and maintains generating facility(ies), while the Generator Operator (GOP) operates generating unit(s) which supply energy. The GOP also performs other services required to support reliable system operations, such as providing regulation and reserve capacity, and sharing data with BAs and TOPs as required. Many entities are both GOs and GOPs.

The Planning Authority (PA) coordinates and integrates transmission facility and service plans, resource plans, and protection systems, while the Transmission Planner (TP) develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.

Some of the key concepts to ensure the reliability of the electric transmission grid include:

- Voltage Control – Maintaining consistent voltage levels is imperative, as wide deviations in the voltage levels can have severe consequences. Voltage below certain limits could lead to an electric system imbalance or collapse. Voltages above certain limits can exceed insulation capabilities and cause dangerous electric arcs. Winter peak electricity loads include resistive loads such as resistive heating, which has a higher load power factor than during summer peak conditions. Load power factor is an indicator of reactive demand —the higher the load power factor, the lower the reactive power demand. A relatively small percentage change in power factor, such as a change from 88% summer peak load power factor, to a 92% winter peak load power factor, can result in 30% less need for reactive power to be supplied during the winter. Summer peak electricity load includes air conditioning, which, like other induction motors, has lower power factors and consumes more reactive power than winter loads. Even with more stable voltages during winter peak conditions, system operators must continually monitor and evaluate system conditions, examining reactive reserves and voltages, and adjust the system as necessary for secure operation..[143]

- Power Flow/Stability Control – Because of the danger resulting from low voltage levels, voltage stability limits are set to ensure that the unplanned loss of a generator or line will not cause dangerously low voltage levels. Additionally, power (or angle) stability limits are set to ensure that unplanned losses will not cause the remaining generators or lines to lose synchronism (or operate out of step) with each other, causing equipment damage.
- Short-Term and Long-Term Planning – Detailed system planning, design, maintenance, and analysis ensure reliable and safe operation of the system in the near- and long-term. Operations planning assesses day-ahead, week-ahead, seasonal, and up to one-year planning horizons. Short-term planning focuses on one- to five-year planning horizons, and long-term planning evaluates adequate generation resources and transmission capacity to ensure the system will be able to withstand severe contingencies in the future without widespread, cascading outages.
- Coordination and Communication Between Entities –the Reliability Standards encourage principal entities (e.g., Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Distribution Providers) to communicate effectively in real-time to maintain system balance between generation and load, stay within operating limits, and address issues that arise.

Ultimately, the RCs, BAs, TOPs and other responsible entities must work individually and together to comply with the mandatory Reliability Standards and to ensure the continued reliable operation of the bulk power system.

[143] U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" (April 2004) at 26.

Appendix C: RC and TOP Operator Tools and Actions to Operate the BES in Real Time

RCs and TOPs employ system operators and engineers who use various methods to forecast and evaluate upcoming and real-time issues, so as to avoid or mitigate problems that arise in their electric grids. They continually monitor transmission facilities 24 hours a day, seven days a week, for situational awareness of the power grid. System operators typically have available a variety of real-time computer tools for monitoring the system, including State Estimator (SE) and Real-Time Contingency Analysis (RTCA).[144] RC system operators are constantly monitoring RTCA and RTCA-based displays, including lists of facilities that exceed System Operating Limits or have voltages deviating from voltage criteria in real time, and lists of facilities that would exceed System Operating Limits or have voltages deviating from voltage criteria if a contingency were to occur (another system element, such as a line, transformer or generating unit, is outaged) (the latter list is called post-contingency exceedances).

For both real-time and post-contingency limit exceedances, the system operators have a number of step-wise mitigating actions they can take to restore the facilities to within system limits or voltages to within voltage criteria. For simulated post-contingency exceedances, some operator actions are taken before the contingency occurs, while for other post-contingency exceedances, the operator relies on mitigation to be taken only if the contingency were to occur. Operators should only rely on post-contingency mitigation if they are confident that there would be sufficient time to complete the mitigation before adverse system conditions (such as instability or cascading outages) would occur.

The mere fact that an actual or real-time system operating limit is exceeded does not necessarily mean that immediate reduction below the limit is required, although it does require immediate operator action. As an example, RC operators may contact Transmission Owners to determine if a temporarily-higher rating is warranted. For a projected next- or post-contingency System Operating Limit (SOL) exceedance, if also projected to exceed an Interconnection Reliability Operating Limit (IROL, meaning that it could lead to instability, uncontrolled separation, or cascading outages that adversely

[144] SE constructs a representation of the state of the system using voltages, currents, and breaker status from the real-time data, and calculates values for which data are not directly collected; while RTCA runs frequently, for example, every two to six minutes for MISO and SPP, and informs the operators how the system would be affected for the computer-simulated outage or in other words used interchangeably, "for loss of" (FLO) a specific system facility such as a transmission line or a transformer.

impact the reliability of the BES), operators have a maximum of 30 minutes to take actions alleviate the IROL exceedance..[145] Otherwise, operators identify mitigation measures they could take as part of their operating plan, which may include measures that would be implemented prior to, or if the next contingency occurred.

To aid in monitoring and regulating power flows across the transmission system (often referred to as managing transmission "congestion"), system operators in RTO areas define "flowgates," by pairing specific transmission facilities and their associated next contingencies that would compound the transmission facility loading if the associated next contingency occurred. In addition to RTCA, RC operators in the Eastern Interconnection possess computer-based flowgate monitoring tools, which use the shared interchange distribution calculator (IDC) to calculate percentages of power flow impacts that each interchange power transfer schedule has on each flowgate; i.e., its transfer distribution factor, or TDF. For instance, if the need arises to reduce flowgate loading to remain within system operating limits, or in other words, alleviate market "congestion", the flowgate monitoring tool enables the operators to determine the appropriate megawatt power flow amount that can be reduced in the external market transfer to achieve this goal.

To manage the grid, the RC can take a wide-area view of all the regional resources available to it, resulting in a "dispatch stack" that contains generators from all generation-owning members of the region, including utility and non-utility Generator Owners, as well as some generation resources outside the footprint. Many utilize a security constrained economic dispatch (SCED) algorithm to determine the appropriate and least-cost generating units to dispatch at any given time depending on market conditions. SCED aids the RTOs by, among other tasks, simultaneously balancing energy injections and withdrawals, managing congestion, and ensuring adequate operating reserves. The SCED process runs every five minutes to establish dispatch instructions for generators to meet the future load of the next five-minute period. The purpose of the algorithm is to minimize the cost to meet the forecast demand, scheduled interchange, and reserve requirements while also being subject to transmission congestion and other system reliability constraints.

An initial approach to relieving transmission congestion constraints in RCs which are also RTOs is redispatching generation at different locations on the grid, done through SCED. When standard operating limits are reached, i.e., when constraints reach a

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[145] This time is defined as the "Interconnection Reliability Operating Limit T_v" which is the maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.

threshold at which other resources will soon need to be dispatched, market operators/RCs proactively enter constraints into SCED to begin preparation for unanticipated system events. When system operators change the day-ahead generation dispatch schedule to accommodate constraints or unexpected transmission or generation outages, it is known as "security constrained redispatch." If non-cost measures do not alleviate the congestion concerns, operators should utilize least-cost redispatch measures, including initiating market-to-market (M2M) redispatch procedures for reciprocally coordinated flowgates (RCFs) between RTOs, or utilizing a transmission loading relief procedure (TLR), which prioritizes the various types of transmission services, allowing system operators to cut less-firm transportation flows first.

Some RTOs that share a "seam," or common border, including MISO and SPP, utilize the M2M coordination process between the RTOs to assist in maintaining efficient, reliable service for their respective regions. The M2M process allows for both RTOs' RCs to coordinate interface pricing by modeling the same constraint. The previously-defined RCFs are monitored closely to gauge the impact of market flows and parallel flows from adjacent regions and markets. MISO and SPP can utilize M2M upon constraint activation in the market. During the course of the Event, MISO and SPP's RC System Operators were in frequent communication with each other, analyzing congestion and engaging in M2M congestion management when necessary to relieve congestion on binding constraints, particularly during the early morning hours of January 17, 2018. Between the hours of 1 am and 10 am CST on January 17, MISO and SPP's RC Operators had approximately 20 calls with each other to discuss grid issues and especially congested constraints, ultimately using M2M to alleviate congestion on several constraints.

RC Operators can issue one or more TLR(s) to curtail transmission flowgate loadings on an hour-by-hour basis. TLRs are used to ration transmission capacity when demand for the transmission is greater than the available capacity. TLRs are typically utilized when the transmission system is overloaded to the point where power flows must be reduced in order to protect the system. The rationing is done based upon a priority structure that lowers or limits the power flows based on size, contractual terms, and scheduling, as opposed to the redispatch of lowest cost generation in M2M.[146] This method can be used in MISO and SPP at the RC's discretion.

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[146] The NERC TLR Procedure is an Eastern Interconnection-wide process that allows Reliability Coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. See https://www.nerc.com/pa/rrm/TLR/Pages/default.aspx

TLR Levels

TLR Levels		
TLR Level	**Reliability Coordinator Action**	**Comments**
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL)violations.	
2	**Hold** T ransfers at present level to prevent SOL or IROL violations.	Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held. See Attachment 1 to IRO-006, Section 2.2.
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process. See Attachment 1 to IRO-006, Section 2.3 and Section 6.0.
3b	**Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.4 and Section 7.0.
4	**Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.	There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.5.
5a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point.	Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced ("pro rata") level. Pro forma tariff also requires curtailment/ REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.6 and Section 6.0.
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.7.
6	**Emergency Procedures**	Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Attachment 1 to IRO-006, Section 2.8.
0	**TLR Concluded**	**Restore** transactions. See Attachment 1 to IRO-006, Section 2.9.

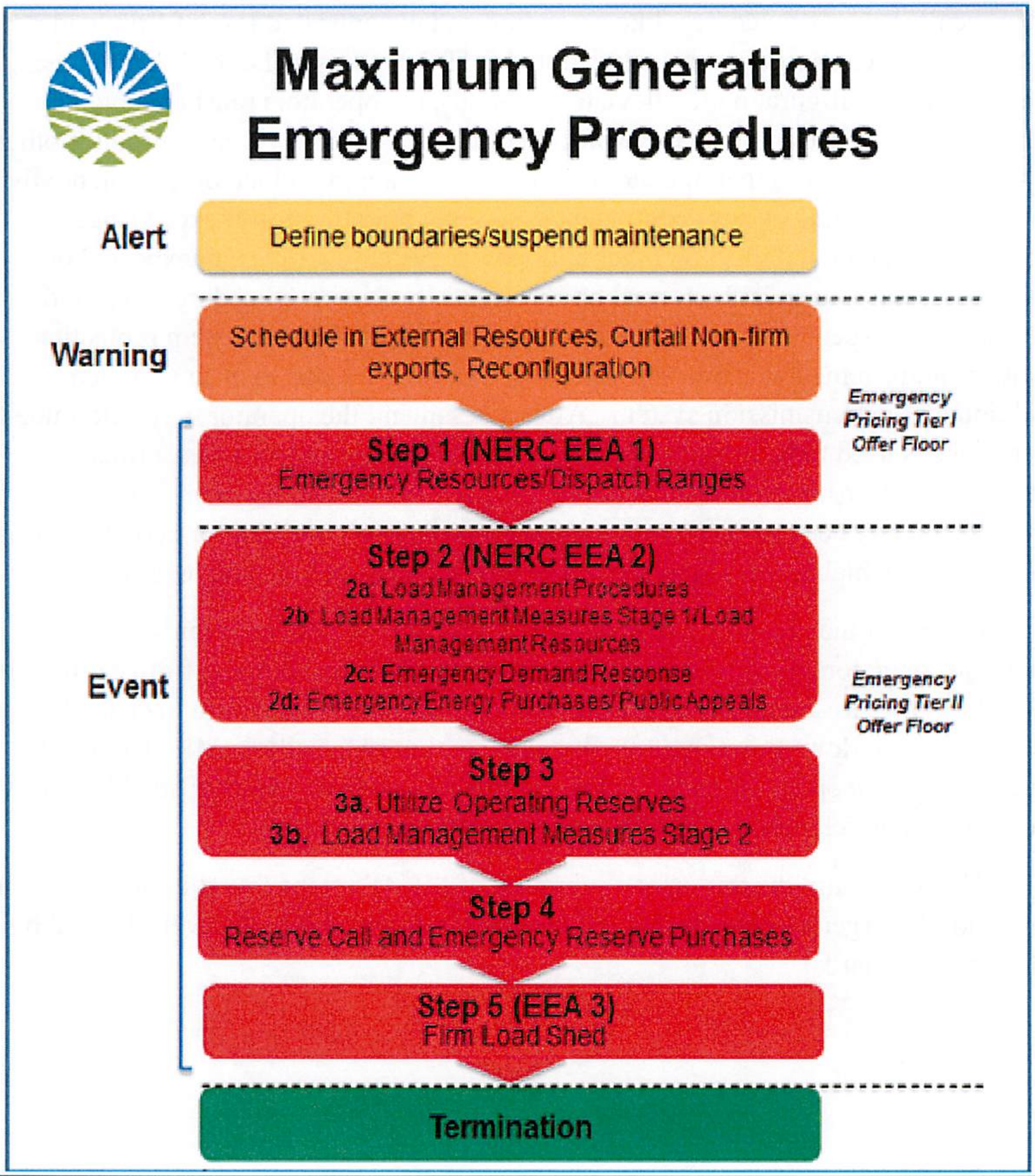
TLR VS M2M (APPLIES TO MISO-SPP)

	TLR	M2M
Relief Calculation Granularity	Hourly	5 minute
Relief Source	Cuts lowest priority schedule	Redispatch of lowest cost generation
Data Quality	Static (except for market's reporting real-time market flow)	Real-time, sub-second
Usage	RC discretion	Upon constraint activation in market
Settlement	None	Based on Firm Flow Entitlement (FFE) usage
Regulation	NERC ORC / NAESB	JOA (FERC)

The RC operators also used transmission reconfiguration to address real-time or post-contingency overloads during this timeframe. The practice of transmission reconfiguration, which involves mitigating the overload by opening and/or a combination of opening and closing switches (i.e. breakers), is typically not the first tool an operator would use to potentially alleviate overloaded facilities, because it brings with it potential reliability tradeoffs. But it still has an important practice in maintaining system reliability and preventing worse outcomes, like cascading and uncontrolled loss of firm load. Transmission reconfiguration is included in the TLR process as Level 4. Before using transmission reconfiguration to alleviate overloads, the operators must conduct an assessment to pre-determine that the proposed reconfiguration will not introduce other reliability issues. Issues that operators would want to avoid include other, potentially more severe, real-time or next-contingency System Operating Limit exceedances (thermal, voltage or stability) on other bulk power system facilities, unexpected or unwanted changes to specific normal or emergency operating procedure steps, and changes to the expected behavior (resulting automatic actions) of system protection schemes and/or remedial action schemes which may be needed to clear a faulted condition on the transmission system. After assessment, the operator may determine that other changes need to be made to avoid one or more of the above issues, or may determine that transmission reconfiguration is not a viable option. Some reconfigurations may have already been studied, with pre-set procedures established for certain overload conditions for which system engineers have already analyzed the above issues.

If none of the preceding actions have eliminated the transmission system conditions, operators may need to use emergency procedures, ranging from calling on Load Modifying Resources to emergency energy purchases, up to firm load shed as a last resort. The high flows throughout the Event Area, but especially in MISO and SPP, caused the system operators to use nearly all available actions, short of shedding firm load, to maintain reliability of the bulk-electric system.

The following illustration is a summary of MISO's steps found in their Maximum Generation Emergency Procedures, and how they relate to the EEA levels defined by the Reliability Standards:



Appendix D: Glossary of Terms Used In Report

Adjacent RC - A Reliability Coordinator whose Reliability Coordinator Area is interconnected with another Reliability Coordinator Area.

Alternating Current (AC) - Electric current that changes periodically in magnitude and direction with time. In power systems, the changes follow the pattern of a sine wave having a frequency of 60 cycles per second in North America. AC is also used to refer to voltage which follows a similar sine wave pattern.

Ambient Conditions - Common, prevailing, and uncontrolled atmospheric conditions at a particular location, either indoors or out. The term is often used to describe the temperature, humidity, and airflow or wind that equipment or systems are exposed to.

Asynchronous - In AC power systems, two systems are asynchronous if they are not operating at exactly the same frequency. Two systems may also be considered asynchronous if, at potential interconnection points, there is a significant difference in phase angle between their respective voltage waveforms.

Bulk Electric System - All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. The NERC Glossary of Terms Used in the Reliability Standards contains the list of inclusions and exclusions, and can be found at https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

Capacitor - A capacitor is a device that stores an electric charge. Although there is energy associated with the stored charge, it is negligible in terms of its capability to serve load. A capacitor bank is made of up of many individual capacitors. Its purpose is to provide reactive power to the system to help support system voltage by compensating for reactive power losses incurred in the delivery of power.

Cascading - The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Constrained System Conditions - Conditions where multiple transmission facilities (lines, transformers, breakers, etc.) are approaching, are at, or are beyond their System Operating Limits.

Conductor - In physical terms, any material, usually metallic, exhibiting a low resistance to the flow of electric current. A conductor is the opposite of an insulator. In electric power systems, the term conductor generally refers to the actual wires in overhead transmission and distribution lines, underground cables, and the metallic tubing used for busses in substations. Aluminum and copper are the predominant metals used for conductors in power systems.

Contingency - The unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Contingency Reserve - Contingency reserve is the provision of capacity deployed by a Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements. Adequate generating capacity must be available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. This capacity is necessary to replace capacity and energy lost due to forced outages of generation or transmission equipment.

Curtail / Curtailment - A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.

Demand - 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.

Demand Side Management - All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.

Derate - A reduction in a generating unit's net dependable capacity.

Direct Current (DC) - Electric current that is steady and does not change in either magnitude or direction with time. DC is also used to refer to voltage and, more generally, to smaller or special purpose power supply systems utilizing direct current either converted from AC, from a DC generator, from batteries, or from other sources such as solar cells.

Distribution Factor - The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

Emergency - Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.

Emergency Rating - The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or MVAr or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Energy Emergency – A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.

Energy Management System (EMS) - A system of computer-aided tools used by system operators to monitor, control and optimize system performance.

Export – In electric power systems, exports refer to energy that is generated in one power system, or portion of a power system, and transmitted to, and consumed in, another.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Facility Rating - The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Firm Load (or Firm Demand) - That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

Firm Transmission Service/Capacity - The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.

Flowgate – 1) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

Force Majeure - A superior force, "act of God" or unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

Forced Outage – 1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2) The condition in which the equipment is unavailable due to unanticipated failure.

Generation – The process of producing electrical energy from other sources of energy such as coal, natural gas, uranium, hydro power, wind, etc. More generally, generation can also refer to the amount of electric power produced, usually expressed in kilowatts (kW) or megawatts (MW) and/or the amount of electric energy produced, expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generator - Generally, a rotating electromagnetic machine used to convert mechanical power to electrical power. The large synchronous generators common in electric power systems also serve the function of voltage support and voltage regulation by supplying or withdrawing reactive power from the transmission system, as needed.

Grid - An electrical transmission and/or distribution network. Broadly, an entire interconnection.

Heat Tracing – The application of a heat source to pipes, lines, and other equipment which, in order to function properly, must be kept from freezing. Heat tracing typically takes the form of a heating element running parallel with and in direct contact with piping.

Hour Ending - Data measured on a Clock Hour basis.

Interchange – Energy transfers that cross Balancing Authority boundaries.

Interchange Distribution Calculator (IDC) - The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.

Import – In electric power systems, imports refer to energy that is transmitted to, and consumed in one power system, which is generated in another power system, or portion of another power system.

Independent System Operator (ISO) - An organization responsible for the reliable operation of the power grid in a particular region and for providing open access transmission access to all market participants on a nondiscriminatory basis.

Interchange - Electrical energy transfers that cross Balancing Authority boundaries.

Interchange Schedule - An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.

Interconnection – A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Interconnection Reliability Operating Limit - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.

Interruptible Load - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - See Demand (Electric).

Load-serving – Serves the electrical demand and energy requirements of its end-use customers.

Load Shed – The reduction of electrical system load or demand by interrupting the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations. In cases of capacity shortages, load shedding is often performed on a rotating basis, systematically and in a predetermined sequence.

Market Flow - The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.

Most Severe Single Contingency (MSSC) - The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Near-Term – The time period that covers the next day to multiple days ahead of the operating day.

Operating Plan - A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Operating Process - A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

Operational Planning Analysis - An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. It consists of spinning and non-spinning reserve.

Outage – The period during which a generating unit, transmission line, or other facility is out of service. Outages are typically categorized as forced, due to unanticipated problems that render a facility unable to perform its function and/or pose a risk to personnel or to the system, or scheduled / planned for the sake of maintenance, repairs, or upgrades.

Peak Load (or Peak Demand) – 1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

Post-Contingency - The resulting power system conditions (determined by computer simulation, or by actual real-time data) following the unexpected and sudden failure or outage of a power system component, such as a generator, transmission line, transformer, or other electrical element.

Power - In physics, power is defined as the rate at which energy is expended to do work. In the electric power industry, power is measured in watts (W), kilowatts (1 kW = 1,000 watts), megawatts (1 MW = 1 million watts), or gigawatts (1 GW = 1 billion watts). For reference, 1 kW = 1.342 horsepower (hp).

Power System - The collective name given to the elements of the electrical system. The power system includes the generation, transmission, distribution, substations, etc. The term power system may refer to one section of a large interconnected system or to the entire interconnected system.

Power Transfer Distribution Factor - In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.

Rating - The operational limits of a transmission system element under a set of specified conditions. In power systems, equipment and facility power-handling ratings are usually expressed either in megawatts (MW) or in mega-volt-amperes (MVA). The term is also sometimes used to describe the output capability of generators.

Reactive Power – The portion of electricity that establishes and sustains the electric and magnetic fields of AC equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It is also needed to make up for the reactive losses incurred when power flows through transmission facilities. Reactive power is supplied primarily by generators, capacitor banks, and the natural capacitance of overhead transmission lines and underground cables (with cables contributing much more per mile than lines). It can also be supplied by static VAR converters (SVCs) and other similar equipment utilizing power electronics, as well as by synchronous condensers. Reactive power directly influences system voltage such that supplying additional reactive power increases the voltage. It is usually expressed in kilovars (KVAr) or megavars (MVAr), and is also known as "imaginary power."

Real-Time – Bulk Electric System conditions, characteristics and/or data representing what actually occurred at specific times or timeframes during the Event.

Real-Time Assessment – An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Real-Time Contingency Analysis (RTCA) – A computer application which evaluates system conditions using real-time data to assess potential (post-contingency) operating conditions.

Regional Entity - An independent, regional entity having delegated authority from NERC to propose and enforce Reliability Standards and to otherwise promote the effective and efficient administration of bulk-power system reliability.

Regional Transmission Organization (RTO) - A voluntary organization of electric Transmission Owners, transmission users and other entities approved by FERC to efficiently coordinate electric transmission planning (and expansion), operation, and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Reliability Coordinator Area - The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in real-time.

Stability – The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

State Estimator – A computer application which evaluates system conditions using real-time data to assess existing operating conditions.

Transformer - A type of electrical equipment in the power system that operates on electromagnetic principles to increase (step up) or decrease (step down) voltage.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Line – A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.

Trip - This refers to the automatic disconnection of a generator or transmission line by its circuit breakers.

Voltage - The force characteristic of a separation of charge that causes electric current to flow. The symbol is “V” and units are volts or kilovolts (kV).

Wide Area - The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

Appendix E: Categories of NERC Registered Entities

All registered entities fall within one or more of the following categories must register with NERC. Many entities carry out multiple roles and therefore have multiple registrations.

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Generator Operator	GOP	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	Entity that owns and maintains generating Facility(ies).
Planning Authority/Planning Coordinator	PA/PC	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Transmission Operator	TOP	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.
Transmission Owner	TO	The entity that owns and maintains transmission Facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.

Appendix F: Acronyms Used in the Report

AC	Alternating Current
AECI	Associated Electric Cooperative, Inc.
BA	Balancing Authority
BES	Bulk Electric System
CST	Central Standard Time
DC	Direct Current
DSM	Demand-Side Management
EEA	Energy Emergency Alert
EHV	Extra-High Voltage
EMS	Energy Management System
EOP	Emergency Operations Planning
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FRAC	Forward Reliability Assessment Commitment
GFCI	Ground Fault Circuit Interrupter
GO	Generator Owner
GOP	Generator Operator
HVDC	High Voltage Direct Current
IROL	Interconnection Operating Reliability Limit
ISO	Independent System Operator
kV	Kilovolt
LBA	Local Balancing Authority
LG&E/KU	Louisville Gas and Electric/Kentucky Utilities
LMR	Load Modifying Resources
MSSC	Most Severe Single Contingency
MISO	Midcontinent Independent System Operator, Inc.
MRO	Midwest Reliability Organization
MVA	Megavolt-Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
OPA	Operational Planning Analysis
PC	Planning Coordinator
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RDT	Regional Directional Transfer
RDTL	Regional Directional Transfer Limit
RF	ReliabilityFirst Corporation
RTCA	Real-Time Contingency Analysis

RTO	Regional Transmission Organization
RTOC	Regional Transfer Operating Committee
RTOP	Regional Transfer Operating Procedure
SCED	Security Constrained Economic Dispatch
SCRD	Security Constrained Redispatch
SERC	SERC Corporation
SeRC	Southeastern Reliability Coordinator
SOL	System Operating Limit
SPP	Southwest Power Pool, Inc.
SRPBC	Sub-Regional Power Balance Constraint
TLR	Transmission Loading Relief
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TVA	Tennessee Valley Authority
UDS	Unit Dispatch System
VSA	Voltage Stability Analysis
WECC	Western Electricity Coordinating Council
wEFOR	Weighted Equivalent Forced Outage Rate
WSC	Worst Single Contingency

Appendix G: 2011 Recommendations Regarding Preparation for Cold-Weather Events

In September, 2011, after an inquiry into the controlled shedding of 4,000 MW of firm load in Texas's ERCOT footprint, NERC and the Commission issued a group of recommendations aimed at helping other entities in warm climates avoid losing firm load when extreme cold weather strikes. Many of those recommendations are equally appropriate for this event, so we reprint them below, with minor edits as shown in italics. Supporting text has been edited to make it more broadly applicable. The numbers [may] not be sequential due to the omission of highly ERCOT-specific recommendations. We also briefly discuss actions taken in response to the recommendations.

PLANNING AND RESERVES

1. Balancing Authorities, Reliability Coordinators, Transmission Operators and Generator Owner/Operators in *summer peaking areas* should consider preparation for the winter season as critical as preparation for the summer peak season.

The large number of generating units that failed to start, tripped offline or had to be derated during the event demonstrates that the generators did not adequately anticipate the full impact of the cold weather. While plant personnel and system operators, in the main, performed admirably during the event, more thorough preparation for cold weather could potentially have prevented many of the weather-related outages. Capacity margins going into the winter were adequate on paper. But those margins did not take into account whether many of the units counted would be capable of running during the severe cold weather that materialized in mid-January. While the probability of a winter event in the predominantly summer peaking south-central U.S. appears to be low, shedding load in the winter places lives and property at risk. The task force recommends that all entities responsible for the reliability of the bulk power system in the Southwest prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season.

2. Planning authorities should augment their winter assessments with sensitivity studies incorporating *conditions like the Event* to ensure there are sufficient generation and reserves in the operational time horizon.

All of the affected RCs undertake planning studies to ensure that sufficient reserves are available to meet seasonal peak loads. *However, conditions experienced on January 17 were more severe than predicted in seasonal studies.*

Planners should undertake a sensitivity study, using the 2011 actual conditions [*or another actual severe winter event*] as a possible extreme scenario that reflects expected limits on available generation. These limits would include those due to planned outages, limited operations during periods of extreme cold weather, ambient temperature operating limitations, and any likely loss of fuel sources. This sensitivity study should be used by operational planners to identify various system stress points, and by Reliability Coordinators, Balancing Authorities, and Transmission Operators to improve and refine strategies to preserve the reliability of the bulk power system during an extended cold weather event. These strategies should include procedures relating to utilization of generators with fuel switching capabilities and implementing early start-ups for generators with long start-up times.

3. Balancing Authorities and Reserve Sharing Groups should review the distribution of reserves to ensure that they are useable and deliverable during contingencies.

This recommendation is designed to ensure that Balancing Authorities take into account transmission constraints, other demands on reserve sharing resources, the possibility that more than one reserve sharing group member might experience simultaneous emergencies, and other factors that might affect the availability or deliverability of reserves.

4. *This Recommendation was focused on ERCOT's specific outage request protocol, which ERCOT changed as a result of the Recommendation. Some of the supporting text may be helpful and remains below.*

ISOs, RCs and TOPs should consider *whether they have the* authority to cancel previously approved outages in cases of approaching extreme weather conditions, even up to the time of the event itself. In making this evaluation, *they* should take into account the costs that would be imposed on the generator as well as the practical difficulties of returning it to service if plant components are disassembled, as well as the generator's need to perform maintenance at some point while also avoiding the high- demand summer season. In addition to the criteria for outage evaluation currently provided *the report also* recommended *taking* into consideration the potential loss of units based on weather conditions beyond their design limits, and the effects likely to result from the totality of scheduled and proposed outages.

In furtherance of these criteria, *ISOs, RCs and TOPs* should:

- Have available the design temperatures of all generation resources.
- Take into consideration as an extreme weather event approaches which plants will not be available based on their design temperature limits.

- Consider increasing reserve levels during extreme weather events.

- Commit, for purposes of serving load and being counted as reserves, only those plants whose temperature design limits fall within the forecast temperature range.

- Determine, prior to approving an outage, if the combination of previously approved scheduled outages with the proposed scheduled outages might cause reliability problems.

5. *RCs and TOPs* should consider *increasing* responsive reserve requirement*s* in extreme low temperatures, (ii) direct*ing* generating units to utilize preoperational warming prior to anticipated severe cold weather, and (iii) verify*ing* with each generating unit its preparedness for severe cold weather, including operating limits, potential fuel needs and fuel switching abilities.

ERCOT data on forced outages during the 50 coldest days between 2005-2011 show a correlation between low temperatures and forced outages. This was demonstrated not only by the February 2011 event but also by the 1989 event; in both cases, extremely low temperatures led to the loss of large amounts of generation and the implementation of rolling blackouts. Increasing the amount of responsive reserves going into a cold weather event would compensate for the probability that a number of generating units might fail, and would provide better response to system instability in the event of such losses. Additionally, pre-operational warming would help prevent freezing and identify other operational problems. Running a unit prior to the start of extreme cold weather would utilize the unit's own radiant heat to help prevent freezing. And starting it up would permit correction of any problems that otherwise would not be noticed until the unit was called upon for performance. While pre-operational warming has considerable value, issues of whether or how generators are to be compensated for taking such actions at ERCOT's direction would need to be addressed.

COORDINATION WITH GENERATOR OWNERS/OPERATORS

6. Transmission Operators, Balancing Authorities, and Generator Owner/Operators should consider developing mechanisms to verify that units that have fuel switching capabilities can periodically demonstrate those capabilities.

During the *ERCOT* cold weather event, a quarter of the 20 units that attempted to switch fuel were unsuccessful. If a unit represents itself as having fuel switching capability, verification of the adequacy of its capability would provide useful information to the Balancing Authority or Transmission Operator as to the availability of that unit in the event of natural gas curtailments. Fuel switching verification might consist of the following:

- Documented time required to switch equipment,
- Documented unit capacity while on alternate fuel,
- Operator training and experience,
- Fuel switching equipment problems, and
- Boiler and combustion control adjustments needed to operate on alternate fuel.

7. Balancing Authorities, Transmission Operators and Generator Owners/Operators should take the steps necessary to ensure that black start units can be utilized during adverse weather and emergency conditions.

8. Balancing Authorities, Reliability Coordinators and Transmission Operators should require Generator Owner/Operators to provide accurate ambient temperature design specifications. Balancing Authorities, Reliability Coordinators and Transmission Operators should verify that temperature design limit information is kept current and should use this information to determine whether individual generating units will be available during extreme weather events.

In order to ascertain actual capabilities during extreme weather conditions, Balancing Authorities and Reliability Coordinators should require Generator Owner/Operators to provide accurate ambient temperature design operating limits for each generating unit that is included in its portfolio (including the accelerated cooling effect of wind), and update them as necessary. These limits should take into account all temperature-affected generator, turbine, and boiler equipment, and associated ancillary equipment and controls. The Balancing Authorities should take steps to verify that Generator Owner/Operators comply with this requirement, and should prepare for the winter season by developing a catalog of individual generating unit temperature limitations. These should be used to determine if forecast temperatures place a particular generating unit in a high-risk category. Lastly, Balancing Authorities and Reliability Coordinators should consider the feasibility of counting on a generating unit whose rating falls below forecast weather conditions, and should consider whether to take into account weather-related design specifications in ranking units in the supply stack during critical weather events.

9. Transmission Operators and Balancing Authorities should obtain from Generator Owner/Operators their forecasts of real output capability in advance of an anticipated severe weather event; the forecasts should take into account both the temperature beyond which the availability of the generating unit cannot be assumed, and the potential for natural gas curtailments.

This Recommendation previously referred to Reliability Standard TOP-002-02 R15, *which is no longer in effect. Balancing Authorities and Transmission Operators could obtain similar, although perhaps not exact, results through Reliability Standard TOP-003-3, which allows Balancing Authorities and Transmission Operators to designate specific data required from entities like the Generator Owner/Operators.* Doing so would allow operators to make proactive decisions prior to the onset of cold weather, including but not limited to:

- Requesting cancellation of planned outages,
- Directing advanced fuel switching,
- Directing startup of units with startup times greater than one day,
- Requesting startup of seasonally mothballed units, and
- Making advance requests for conservation.

Consideration needs to be given to ensuring that there is an adequate cost recovery mechanism in place for reliability measures taken by the generators at *the* direction *of the Balancing Authority or Transmission Operator.*

10. Balancing Authorities should plan ahead so that emergency enforcement discretion regarding emission limitations [*from state or Federal environmental* authorities] can be quickly implemented in the event of severe capacity shortages.

WINTERIZATION

11. States should examine whether Generator/Operators ought to be required to submit winterization plans, and should consider enacting legislation where necessary and appropriate.

The task force determined during its inquiry that certain generators were better prepared than others to respond to the February [2011] cold weather event. In many cases the entities that performed well had emergency operations or winterization plans in place to provide direction to employees on how to keep their units operating. Although the implementation of a winterization plan cannot guarantee that a unit will not succumb to cold weather conditions, it can reduce the likelihood of unit trips, derates and failed starts.

. . .[T]he task force recommends that planning take into account not only forecasts but also historical weather patterns, so that the required procedures accommodate

unusually severe events. Statutes should ideally direct utility commissions to develop best winterization practices for its state, and make winterization plans mandatory.
Lastly, it is recommended that legislatures consider granting utility commissions the authority to impose penalties for non-compliance, as well as to require senior management to acknowledge that they have reviewed the winterization plans for their generating unit, that the plans are an accurate representation of the winterization work completed, and that they are appropriate for the unit in light of seasonal weather conditions. *In 2011,* NERC staff concluded there would be a reliability benefit from amending the EOP Reliability Standards to require Generator Owner/Operators to develop, maintain, and implement plans to winterize plants and units prior to extreme cold weather, in order to maximize generator output and availability.
Accordingly, NERC intends to submit a Standard Authorization Request, the first step in the Reliability Standards development process, proposing modifications to the Reliability Standards for Emergency Preparedness and Operations. *Although NERC did submit the Standard Authorization Request, no such modification was made to the Reliability Standards.*

Plant Design

12. Consideration should be given to designing all new generating plants and designing modifications to existing plants (unless committed solely for summer peaking purposes) to be able to perform at the lowest recorded ambient temperature for the nearest city for which historical weather data is available, factoring in accelerated heat loss due to wind speed.

The ideal time to prepare a generating unit to withstand cold temperatures is in the design stage. For that reason, the low temperatures and wind chills that can occur during the occasional severe storm should be incorporated in the design process.

13. The temperature design parameters of existing generating units should be assessed.

The task force found that for existing generating units, it is often not known with any specificity at what temperature the unit will be able to operate, or to what temperature heat tracing and insulation can prevent the water or moisture in its critical components from freezing. For that reason, Generator Owner/Operators should conduct engineering analyses to ascertain each unit's operating parameters, and then take appropriate steps to ensure that each unit will be able to achieve the optimum level of performance of which it is capable.

The task force recommends the following:

- Each Generator Owner/Operator should obtain or perform a comprehensive engineering analysis to identify potential freezing problems or other cold weather operational issues. The analysis should identify components/systems that have the potential to: initiate an automatic unit trip, prevent successful unit start-up, initiate automatic unit runback schemes and/or cause partial outages, adversely affect environmental controls that could cause full or partial outages, adversely affect the delivery of fuel to the units, or cause other operational problems such as slowed valve/damper operation.

- If a Generator Owner/Operator does not have accurate information about the ambient temperature to which an existing unit was designed, or if extensive modifications have been made since the unit was designed (including changes to plant site), it should obtain an engineering analysis regarding the lowest ambient temperatures at which the unit can reliably operate (including wind chill considerations).

- Each Generator Owner/Operator should ensure that its heat tracing, insulation, lagging and wind breaks are designed to maintain water temperature (in those lines with standing water) at or above 40 degrees when ambient temperature, taking into account the accelerated heat loss due to wind, falls below freezing.

- Each Generator Owner/Operator should determine the duration that it can maintain water, air, or fluid systems above freezing when offline, and have contingency plans for periods of freezing temperatures exceeding this duration.

Maintenance/inspections generally

14. Generator Owner/Operators should ensure that adequate maintenance and inspection of freeze protection elements be conducted on a timely and repetitive basis.

The task force found a number of inadequacies in generating units' preparations for winter performance. These included a lack of accountability and senior management review, lack of an adequate inspection and maintenance program, and failure to perform engineering analyses to determine the correct capability needed for their protection equipment.

The task force recommends the following:

- Each Generator Owner/Operator's senior management should establish policies that make winter preparation a priority each fall, establish personnel accountability and audit procedures, and reinforce the policies annually.

- Each Generator Owner/Operator should develop a winter preventive maintenance program for its freeze protection elements, which should specify inspection and testing intervals both before and during the winter. At the end of winter, an additional round of inspections and testing should be performed and an evaluation made of freeze protection performance, in order to identify potential improvements, required maintenance, and freeze protection component replacement for the following winter season.

- Each Generator Owner/Operator should prioritize repairs identified by the inspection and testing the proper functioning of freeze protection systems will be completed before the following winter.

- Each Generator Owner/Operator should use the recommended comprehensive engineering analysis, combined with previous lessons learned, to prepare and update a winter preparation checklist. Generator Owner/Operators should update checklists annually, using the previous winter's lessons learned and industry best practices.

Specific Freeze Protection Maintenance Items

The task force found that many generating units tripped, were derated, or failed to start as a result of problems associated with a failure to install and maintain adequate freeze protection systems and equipment. Based on these findings, on an examination of freeze protection systems of many of the affected generating units, and in some case on standards issued by the Institute of Electrical and Electronics Engineers, the task force has prepared a number of recommendations designed to prevent a repeat of the spotty generator performance experienced during the February cold weather event. Of course, specific actions should conform to best industry practices at the time improvements are made, as well as to the requirements of any mandatory winterization standards imposed by regulatory or legislative bodies.

Heat tracing

15. Each Generator Owner/Operator should inspect and maintain its generating units' heat tracing equipment.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins and before forecast freezing weather, inspect the power supply to all heat trace circuits, including all breakers and fuses.

- Each Generator Owner/Operator should, before each winter begins and before forecast freezing weather, inspect the continuity of all heat trace circuits, check the integrity of all connections in the heat trace circuits, and ensure that all insulation on heat traces is intact. This inspection should include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation which could cause grounds.

- Each Generator Owner/Operator should, before each winter begins, inspect, test, and maintain all heat trace controls or monitoring devices for proper operation, including but not limited to thermostats, local and remote alarms, lights, and monitoring cabinet heaters.

- Each Generator Owner/Operator should, before each winter begins, test the amperage and voltage for its heat tracing circuits and calculate whether the circuits are producing the output specified in the design criteria, and maintain or repair the circuits as needed.

- Each Generator Owner/Operator should be aware of the intended useful life of its heat tracing equipment and should plan for its replacement in accordance with the manufacturer's recommendations.

Thermal Insulation

16. Each Generator Owner/Operator should inspect and maintain its units' thermal insulation.

Specifically, the task force recommends:

- Each Generator Owner/Operator should, before each winter begins, inspect all accessible thermal insulation and verify that there are no cuts, tears, or holes in the insulation, or evidence of degradation.

- Each Generator Owner/Operator should require visual inspection of thermal insulation for damage after repairs or maintenance have been conducted in the vicinity of the insulation.

- Each Generator Owner/Operator should ensure that valves and connections are insulated to the same temperature specifications as the piping connected to it.

- Each Generator Owner/Operator should be aware of the intended useful life of the insulation of water lines and should plan for its replacement in accordance with the manufacturer's recommendations.

Use of Wind breaks/enclosures

17. Each Generator Owner/Operator should plan on the erection of adequate wind breaks and enclosures, where needed.

Specifically, the task force recommends:

- A separate engineering assessment should be performed for each generating unit to determine the proper placement of temporary and/or permanent wind breaks or enclosures to protect and prevent freezing of critical and vulnerable elements during extreme weather.

- Temporary wind breaks should be designed to withstand high winds, and should be fabricated and installed before extreme weather begins.

- Generator Owner/Operators should take into account the fact that sustained winds and/or low temperatures can result in heat loss and freezing even in enclosed or semi-enclosed areas.

Training

18. Each Generator Owner/Operator should develop and annually conduct winter-specific and plant-specific operator awareness and maintenance training.

Operator training should include awareness of the capabilities and limitations of the freeze protection monitoring system, proper methods to check insulation integrity and the reliability and output of heat tracing, and prioritization of repair orders when problems are discovered.

Other Generator Owner/Operator Actions

19. Each Generator Owner/Operator should take steps to ensure that winterization supplies and equipment are in place before the winter season, that adequate staffing is in place for cold weather events, and that preventative action in anticipation of such events is taken in a timely manner.

Specifically, the task force recommends:

- Each Generator Owner/Operator should maintain a sufficient inventory of supplies at each generating unit necessary for extreme weather preparations and operations.

- Each Generator Owner/Operator should place thermometers in rooms containing equipment sensitive to cold and in freeze protection enclosures to ensure that temperature is being maintained above freezing and to determine the need for additional heaters or other freeze protection.

- During extreme cold weather events, each Generator Owner/Operator should schedule additional personnel for around-the-clock coverage.

- Each Generator Owner/Operator should evaluate whether it has sufficient electrical circuits and capacity to operate portable heaters, and perform preventive maintenance on all portable heaters prior to cold weather.

- Each Generator Owner/Operator should drain any non-critical service water lines in anticipation of severe cold weather.

Transmission Facilities

20. Transmission Operators should ensure that transmission facilities are capable of performing during cold weather conditions.

Transmission Operators reported several incidents of unplanned outages during the February 2011 event as a result of circuit breaker trips, transformer trips, and other transmission line issues. Although these outages did not generally contribute materially to any transmission limitations, some transmission breaker outages did lead to the loss of generating units. Many breaker trips were the result of low air in the breaker, low sulfur hexa-fluoride (SF6) gas pressure, failed or inadequate heaters, bad contacts, and gas leaks.

Specifically, the task force recommends:

- Transmission Owner/Operators should ensure that the SF6 gas in breakers and metering and other electrical equipment is at the correct pressure and temperature to operate safely during extreme cold, and also perform annual maintenance that tests SF6 breaker heaters and supporting circuitry to assure that they are functional.

- Transmission Owner/Operators should maintain the operation of power transformers in cold temperatures by checking heaters in the control cabinets, verifying that main tank oil levels are appropriate for the actual oil temperature, checking bushing oil levels, and checking the nitrogen pressure if necessary.

- Transmission Owner/Operators should determine the ambient temperature to which their equipment, including fire protection systems, is protected (taking into account the accelerated cooling effect of wind), and ensure that temperature requirements are met during operations

24. All Transmission Operators and Balancing Authorities should examine their emergency communications protocols or procedures to ensure that not too much responsibility is placed on a single system operator or on other key personnel during an emergency, and should consider developing single points of contact (persons who are not otherwise responsible for emergency operations) for communications during an emergency or likely emergency.

The task force's review of incidents during the event, as well as of operating procedures and protocols in place at the time, indicated that critical employees such as operators had numerous responsibilities that, while manageable in non-emergency situations, could prove impossible to meet during the often-compressed time frame of an emergency situation. In at least one instance, overloading a single on-call operations representative appears to have led to a delay in making emergency power purchases.

LOAD SHEDDING

25. Transmission Operators and Distribution Providers should conduct critical load review for gas production and transmission facilities, and determine the level of protection such facilities should be accorded in the event of system stress or load shedding.

Keeping gas production facilities in service is critical to maintaining an adequate supply of natural gas, particularly in the Southwest where there is a relatively small amount of underground gas storage. And keeping electric-powered compressors running can be important in maintaining adequate pressure in gas transmission lines.
The task force suggests that a review of curtailment priorities be made, to consider whether gas production facilities should be treated as protected loads in the event of load shedding.

26. Transmission Operators should train operators in proper load shedding procedures and conduct periodic drills to maintain their load shedding skills.

The task force found that at least one Transmission Operator in WECC experienced a minor delay in initiating its load shedding sequence, due to problems notifying the concerned Distribution Provider. Another Transmission Operator experienced delay in executing its load shedding because the individual operators had never shed load before and had not had recent drills. These incidents underscore the necessity of adequate training in load shedding procedures.

Actions taken in Texas following 2011 Recommendations

Following the issuance of FERC and NERC's guidance in the February 2011 Cold Weather Report, Texas regulators and lawmakers took affirmative action to investigate and improve industry practices during extreme weather events. In that Report, FERC and NERC made several recommendations directed at improving reliability during extreme weather events, including recommending the assessment of whether minimum standards should be adopted for the winterization of gas production and processing facilities and assessments related to the priority and efficiency of natural gas curtailments.[147]

The Texas Public Utility Commission (Texas PUC) required utilities to strengthen their emergency preparedness plans and to ensure those plans included provisions for severe cold weather. The Texas PUC amended its Electric Service Emergency Operations Plans regulation (16 T.A.C. § 25.53) to require that electric generation utilities' emergency operations plans (filed with the Texas PUC) include "a plan for identification of potentially severe weather events, including . . . severely cold weather," a plan for "the inventory of pre-arranged supplies for emergencies," a plan addressing "staffing during severe weather events," "checklists for generating facility personnel to address emergency events," and a plan for "alternative fuel testing if the facility has the ability to utilize alternative fuels." 16 T.A.C. § 25.53(c)(2)(D-G, I) (2018).

The Texas PUC also commissioned a third-party report on best practices for extreme weather preparedness. This report, published in September 2012, made additional recommendations regarding the identification and awareness of extreme weather events, the identification and understanding of critical failure points within plants and adequate staffing levels, and training for such events, and was submitted to the Texas state legislature.

Together, the Texas PUC, the Railroad Commission of Texas, and the Texas State Energy Conservation Office collaborated on an Energy Assurance Plan that was published in November 2012.[148] This Plan demonstrated the thoughtful engagement of these entities on reliability issues surrounding extreme weather events. It included evaluating updates to the 1973 gas curtailment plan and potentially refining the Texas PUC's list of its critical nodes. Additionally, as part of the Plan, ERCOT engaged a third party to conduct a gas curtailment risk study.

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[147] 2011 Report at 214-17.

[148] Texas Energy Assurance Plan, Nov. 2012, found at https://www.puc.texas.gov/industry/electric/reports/energy_assurance/Energy_Assurance_Plan-Texas.pdf (last accessed April 9, 2019).

Appendix H: Source of Figures Used in Report

Figure No.	Title	Created By	Source of Data
1	January 17, 2018 Event Area – Low Temperature Deviation from the Normal Daily Minimum	Commission Staff	NOAA weather data, prepared using ABB Ventyx Velocity Suite© software
2	MISO and SPP RTO Footprints	MISO and SPP	SEAMS WHITE PAPER FOR ORGANIZATION OF MISO STATES (OMS) AND SPP REGIONAL STATE COMMITTEE (RSC) LIAISON COMMITTEE (November 2, 2018) (https://www.spp.org/documents/59006/spp-miso_rsc_oms_response_spp_miso_final_v3.pdf), used by permission from Organization of MISO States.
3	Tie Lines Between MISO and SPP RC Versus Within MISO	Commission Staff	Data provided by entities, prepared using MS® Office 2013
4	Electric Transmission Lines and Cities within the Event Area	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software
5	MISO Midwest to MISO South Intra-Market Regional Directional Transfers (RDT)	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
6	Upcoming Season Forecast 2017/2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Winter Peak Loads		
7	Generation Capacity Data by Fuel Type	Commission Staff	NERC 2017-2018 Winter Reliability Assessment Resource Adequacy Data – Existing On-Peak Generation (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_11202017_%20Final.pdf), and other publicly-available data, prepared using MS® Office 2013
8	Enclosed coal fired power plant in the northeastern United States	Previously obtained permission for publication	"Appendix: Power Plant Design for Ambient Weather Conditions" to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations
9	Non-enclosed coal fired power plant in the northeastern United States	Previously obtained permission for publication	"Appendix: Power Plant Design for Ambient Weather Conditions" to the joint Commission/NERC Staff Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations
10	MISO's Near-term Peak Load Forecasts and Percent Error for MISO South: 5-day, 4-day, 3-day, 2-day, and 1-day ahead of January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
11	MISO's High and Low Temperature Forecasts Used in MISO South Load Forecasts:	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	5-day, 4-day, 3-day, 2-day, 1-day ahead of January 17, 2018		
12	Event Area Approximate Planned and Unplanned Generation Outages, at the Start of January 15, and January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
13	MISO South Region Forecasted Peak Load for January 17, 2018 and Available Generation, at the Start of January 15, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
14	Total Generation Losses Within the Event Area, Beginning January 17, by RC Footprint	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
15	Declarations Made by MISO in Preparation for January 17 and 18	Commission Staff	Data provided by entities, prepared using MS® Office 2013
16	Comparison of Transmission Planning Voltage Criteria (Percent) – Low	Commission Staff	Data provided by entities, and publicly-available information, prepared using MS® Office 2013

	Limits for Relevant Entities in the Event Area		
17	Comparison of Actual Highs and Lows to Average Daily High and Low Temperatures, January 16 through January 18, 2018	NERC Staff	NOAA weather data
18	January 17, 2018 Peak Loads for Relevant Entities	Commission Staff	Data provided by entities, prepared using MS® Office 2013
19	January 17, 2018 System Loads and Average Event Area Temp.	Commission Staff	Data provided by entities, and NOAA weather data, prepared using MS® Office 2013
20	Total Generation Losses Within the Event Area, Beginning January 17, by Approximate Geographical Area	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
21	January 15-19, 2018 – Number of Generation Unit Losses Versus Temperature, by Hour, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Analysis ToolPak
22	Total Unavailable Generation Over	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Time, for January 17, 2018, by RC Footprint		
23	MISO South Region Approximate Generation Outages and Derates January 17, 2018, by 8am Central Time	Commission Staff	Data provided by entities, prepared using MS® Office 2013
24	Total Incremental Unavailable Generation in the Event Area for January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
25	By 2am CST – BES Transmission Congestion Began to Occur	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
26	MISO Wind Forecast Versus Actual for Winter 2017-2018	MISO Market Monitor, Potomac Economics. Used by permission.	https://www.potomaceconomics.com/wp-content/uploads/2018/03/IMM-Quarterly-Report_Winter-2018_final.pdf Slide 28
27	By 6 a.m. CST – Unplanned Outages, Total and as a Percentage of Event Sub-Area Capacity	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
28	By 6am CST, Total Generation Outages and	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013

	Derates Within the Event Area, by Approximate Geographical Area		
29	By 4 a.m. CST – Numerous Additional Transmission Constraints for Wide-Area of South Central U.S.	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
30	By 6am Central – Further Transmission Constraints Occurring for Wide-Area of South Central U.S.	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
31	5am Central: Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Voltages, Early Morning Hours of January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
32	MISO Regional Dispatch Transfer – January 17, 2018	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
33	6am Central: Further Decrease in Southwestern-to-Southeastern Oklahoma 345kV Bus Per	Commission Staff	Data provided by entities, prepared using MS® Office 2013

	Unit Voltages, Early Morning Hours of January 17, 2018		
34	BES Pre-Contingency Voltage Conditions (P.U.) for Select EHV Buses, January 17, 2018, Approximately 6am CST	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
35	BES Voltage Conditions (P.U.) for High Voltage Buses below Normal (Pre-Contingency) Limits, January 17, 2018, Approximately 6am CST	Commission Staff	Data provided by entities, prepared using ABB Ventyx Velocity Suite© software and MS® Office 2013
36	BES Post-Contingency Range of Voltages below Limits for Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC	Commission Staff	Data provided by entities, prepared using MS® Office 2013
37	BES Post-Contingency	Commission Staff	Data provided by entities, prepared using ABB Ventyx

	Voltage Conditions (P.U.) Below Limits for EHV Buses in MISO South, January 17, 2018, at Approximately 06:30am CST, for the Simulated Outage of the MISO South WSC		Velocity Suite© software and MS® Office 2013
38	10am CST: Improvement in Southwestern-to-Southeastern Oklahoma 345 kV per unit Bus Voltages, Early Morning, January 17, 2018	Commission Staff	Data provided by entities, prepared using MS® Office 2013
39	MISO and SPP Wind Output, January 16 through 19, 2018	Entities, Commission Staff	Illustration provided by entities, with additional graphics added using MS® Office 2013
40	January 15-19, 2018 - Causes of Unplanned Generation Outages and Derates for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
41	January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

	Freezing Issues, for Event Area		
42	January 17, 2018 - Causes of Generation Outages for Event Area, By RC	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
43	January 17, 2018 – Causes of Unplanned Generation Outages and Derates for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
44	January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply Problems, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
45	January 17, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
46	January 15-19, 2018 – Sub-causes for Unplanned Generation Outages and Derates due to Fuel Supply	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

	Problems, for Event Area		
47	January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by Number of Generators)	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software
48	January 15-19, 2018 – Fuel Type for Unplanned Generation Outages and Derates due to Freezing Issues, for Event Area (by MW of Generation)	Commission Staff	Data provided by entities, prepared using MS® Office 2013, and Stata® Software

Appendix I: Regional Transfer Operating Committee Event Review Report (September 9, 2018)

Date Prepared: Original Draft - 02/05/2018 and finalized – 09/07/2018

Prepared By: Regional Transfer Operating Committee (RTOC)[1]

Date of Event: 01/17/2018 – 01/18/2018

Party Requesting the Review: Regional Transfer Operating Committee (RTOC)

Event Summary:

MISO Reliability Coordinator Area

On 01/17/2018 and 01/18/2018 MISO and its members managed operations during a period of record cold in the MISO South Region. Record low temperatures in the MISO South region drove significantly higher load than normal for January, see Figure 1. MISO South region peak load of 32.1 GW on January 17th was only 2% lower than the region's all-time peak of 32.7 GW set in August 2015. Operating conditions were further complicated by a significant number of unplanned generator outages and de-rates in real time. A total of 4.5 GW of generation was lost overnight on January 16th and into the morning of January 17th.

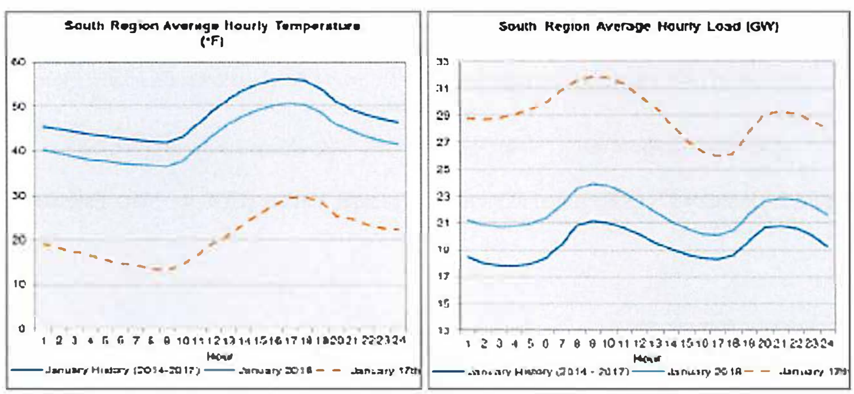

Figure 1. MISO South Region Temperature and Load

Prior to the morning of January 17th MISO issued Conservative Operations and Cold Weather Alerts allowing MISO to commit all available resources and restore all possible transmission outages. Due to significant forced generator outages MISO advanced to Maximum Generation Event Step 2c/d on the morning of January 17th. MISO took all action short of load shed to maintain reliability, including emergency generation, load management, and emergency energy purchases from neighboring Reliability Coordinators. The amount of Load Modifying Resources deployed was 700 MW on the 17th and 930 MW on the 18th. Ultimately what helped MISO avoid shedding load on the morning of January 17 was the emergency energy purchases from neighbors, which were acquired from Georgia System Operations Corp. (150 MW), Southern Co. (700 MW) and TVA (300 MW).

[1] RTOC is a six-member committee comprising two designated representatives for MISO, SPP and the Joint Parties. Joint Parties include: AECI, LG&E/KU, PowerSouth, Southern Co., and TVA.

On the morning of January 17th due to load conditions and the significant number of forced generation outages in the MISO South Region, the Regional Directional Transfer (RDT) flow[2] between the MISO North and Central regions and MISO South region exceeded the North-South Regional Directional Transfer Limit (RDTL)[3] of 3,000 MW, with a maximum exceedance during this timeframe of 936 MW. During this event there was a divergence between the calculated values of the Regional Directional Transfer using MISO UDS data and transfer values based on state estimator data.[4] As shown in Figure 2 below there were periods over January 17 and 18 where the transfer values based on state estimator data (blue line) exceeded 3,000 MW with a maximum value of 4,331 MW on the morning of January 17, while the RDT flow (green line) calculation using UDS showed exceeding 3,000 MW from 0635-0745 EST on January 17. Subsequent examination indicates that the key drivers for the observed divergence between these calculated transfer flows (UDS versus state estimator data) were largely due to differences in actual and forecasted load.

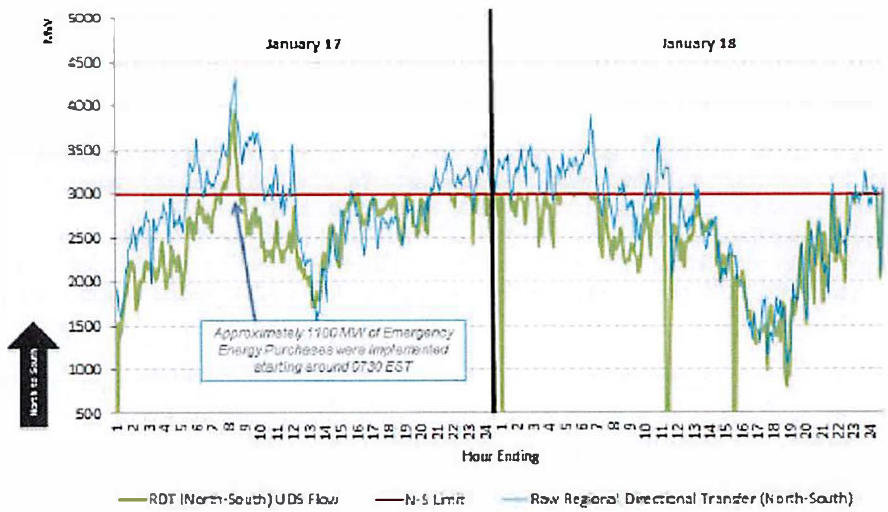

Figure 2. January 17-18 Regional Directional Transfer Values (UDS vs. State Estimator)

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[2] RDT flow is a calculated value defined in the Settlement Agreement entered into between MISO, SPP, and the Joint Parties (AECI, LG&E/KU, PowerSouth, Southern Co., and TVA). The RDT flow calculation at a high-level includes three components to determine the amount and direction of flows between the MISO North and MISO South regions: 1) MISO South region total generation and total load balance; 2) transactions between MISO South and physically connected entities; and 3) pseudo-tie generation flow. The RDT flow is calculated by MISO using data from the latest MISO Unit Dispatch System (UDS) case in accordance with the Settlement Agreement, which represents where load and generation is forecasted to be in the next five-minutes. The results using UDS are intended to serve as a representative proxy for actual flows.

[3] RDTL amount of 3,000 MW for transfers from MISO North to South is defined in the Settlement Agreement, and states if the limit is exceeded that MISO will take action consistent with Good Utility Practice to return RDT flow to the limit within 30 minutes.

[4] The state estimator based transfer flow (blue line in Figure 2) is calculated using real-time load and generation telemetered values instead of data sourced from MISO's Unit Dispatch System.

SPP Reliability Coordinator Area
SPP RC issued a Cold Weather Alert that was in effect from January 15th until 11:00 on the 18th. Loading for SPP RC on January 17th resulted in a new winter peak of 43.5 GW. Due to the high loads in SPP and neighboring systems, combined with the high MISO North to South RDT flows, SPP had numerous flowgates that were above their SOL on a post-contingent basis, and even had some flowgates where SPP and the Transmission Operators (TOP) were depending on post-contingent load shed plans to mitigate the SOL exceedance. In addition to post-contingent exceedances, SPP experienced real-time loading on line sections and was forced to reconfigure transmission to mitigate loading on these elements. SPP also experienced voltage issues during this period in the northeast Oklahoma and Southwest Missouri areas.

To reliably manage SPP's SOL exceedances and low voltages observed on Jan 17th, SPP put into place post-contingent reconfiguration and load-shed plans, in addition to utilizing market redispatch, additional resource commitments, and other pre- and post-contingent manual actions. As a result of these actions, SPP operators were able to maintain reliability for the SPP footprint while also supporting the reliability of neighboring systems. SPP's review of the events of Jan 17th does not indicate any violation of NERC reliability standards for SPP or our members. Additionally SPP remains committed to working with neighboring RCs to improve operational practices and assistance procedures during extreme weather events.

TVA Reliability Coordinator Area
Prior to the excessive RDTF flow, TVA-RC was experiencing heavy loading in all the TVA-RC TOP footprints, and had several N-1 contingencies in the RC footprint that were being mitigated through TVA's normal congestion management processes, and had been planned for during the prior day's Next-Day Analysis. During the excessive high flows from the RDTF, the normal congestion management processes ceased to be effective, resulting in TVA-RC resorting to post-contingency emergency load shed as its only actionable response for numerous mitigations of N-1 contingencies. TVA-RC also had several real-time overloads that had to be mitigated, resulting in additional N-1 overloads during the excessive RDTF flow. TVA was in communication with MISO throughout the morning, and asked MISO to reduce the RDTF as a direct result to the numerous N-1 contingencies.

During this time the TVA BA issued a Conservative Operations Alert and asked for public conservation due to the expected high loads. On the morning of January 17th TVA in response to MISO's request provided 300 MW of emergency energy to Entergy. Starting on January 17th MISO called a TLR 3 [redacted], cutting 1000+ MW non-firm flows into TVA, resulting in an EEA 1 for TVA. This TLR was kept active for 30 hours due to on-going concerns by the MISO RC with overloading if the TLR was closed.

Southeastern Reliability Coordinator Area
Southeastern RC also experienced high flows across its system due to heavy cold weather loads and RDT flow but was able to manage the constraints due to the dynamic facility ratings associated with the low temperatures and redispatch of resources in the Southeastern RC footprint. PowerSouth declared an EEA 1 at 05:38 on the 17th due to all resources being deployed. On the morning of January 17th Southern Company, in response to MISO's request, provided 700 MW of emergency energy and facilitated the purchase of another 150 MW from Georgia System Operations Corp.

The SeRC did not experience any SOL or IROL exceedances on January 17th. However, if there were a potential SOL/IROL exceedance, the SeRC would have implemented its congestion management procedures, up to and including, issuing an Operating Instruction to MISO to reduce their real time dispatch flow. Review of the events of January 17th did not identify any NERC Reliability Standards violations for the SeRC or any of the members in the SeRC footprint.

Lessons Learned/Follow Up Items:

MISO, SPP, TVA, and Southeastern Reliability Coordinators met on 3/15/18 and the RTOC met on 6/7/18, 7/26/18, 8/30/18 to review the event, and to, discuss lessons learned and potential coordination enhancements. RTOC members are actively collaborating on the following items:

Action Items	Status
1) Schedule follow up discussions between the collective RCs to address reliability concerns associated with use, and management, of as available, non-firm RDT flows between 1000MW and the RDTL.	Representatives of the RCs met on 3/15/18 and as part of the RTOC on 6/7/18, 7/26/18, and 8/30/18. At the 8/30/18 meeting each RC provided an overview of their emergency procedures.
2) Enhance communications among Reliability Coordinators during and prior to emergency events. 3) Clarify expectations for normal operations and extreme events where BAs/RCs are forced to implement redispatch, reconfiguration or manual load shed to maintain reliability when RDT flows are in excess of 1000 MWs.	1) MISO has provided SPP and the Joint Parties the process to sign-up for MISO's real-time and market notification emails MISO uses to communicate system conditions. 2) Anticipate items 2 and 3 will be addressed as part of enhancements to the existing Regional Transfer Operating Procedure among MISO, SPP, and the Joint Parties. 4) Procedures for normal operations and extreme events under development. 4) Goal is to have the enhanced procedures finalized no later than November 1, 2018 in advance of the winter season.
4) Refine processes used to manage reserve levels in MISO South Region to mitigate potential RTDL exceedances.	1) MISO made a FERC filing (ER18-1464) on April 27, 2018 to allow for the MISO reserve procurement process to take into account regional transfer constraints. 2) Filing was accepted by FERC on August 23, 2018 with an effective date of August 26, 2018. 3) MISO is developing a process to share forecasted regional transfers with SPP, TVA, and Southeastern RCs.

. Action Items	Status
5) Better alignment of UDS and State Estimator RDT flow values. Explore alternatives to using UDS versus State Estimator calculated RDT for real time operations.	1) MISO has identified the likely causes of the divergence between UDS and State Estimator calculated regional transfer values. 2) First fix scheduled to be implemented by MISO in mid-September, which will modify the load measurement value used in UDS to better align with State Estimator loads. 3) MISO to create metrics to monitor alignment performance and will report out to SPP/JPs in December.
6) Review usage of the TLR process on January 17/18 and address concerns that MISO's "as-available non-firm" flows appeared to have higher priority than tagged non-firm service and apply lessons learned to future TLRs.	1) Discussed at RTOC meeting on 6/7 and 7/30. 2) MISO has discussed with operators the use of TLR on January 17/18 and areas for improvement.
7) Enhance processes for acquiring/delivering emergency energy. Develop and implement a plan for collective Reliability Coordinator drills to exercise Emergency Energy transfers.	1) MISO has developed a training plan for emergency energy purchases. 2) Working with SPP and Joint Parties to schedule a tabletop exercise on emergency energy purchases in September. 3) MISO working on establishing a drill cadence on emergency energy purchases with each neighboring BA.
8) Enhance IDC process to calculate RDT flow impacts on flowgates.	1) IDC Working Group has assigned a sub-group to work on this action item. 2) MISO is developing a tool to calculate the impact of RDT flow on flowgates. Targeting having available for testing by IDC sub-group by mid-September.

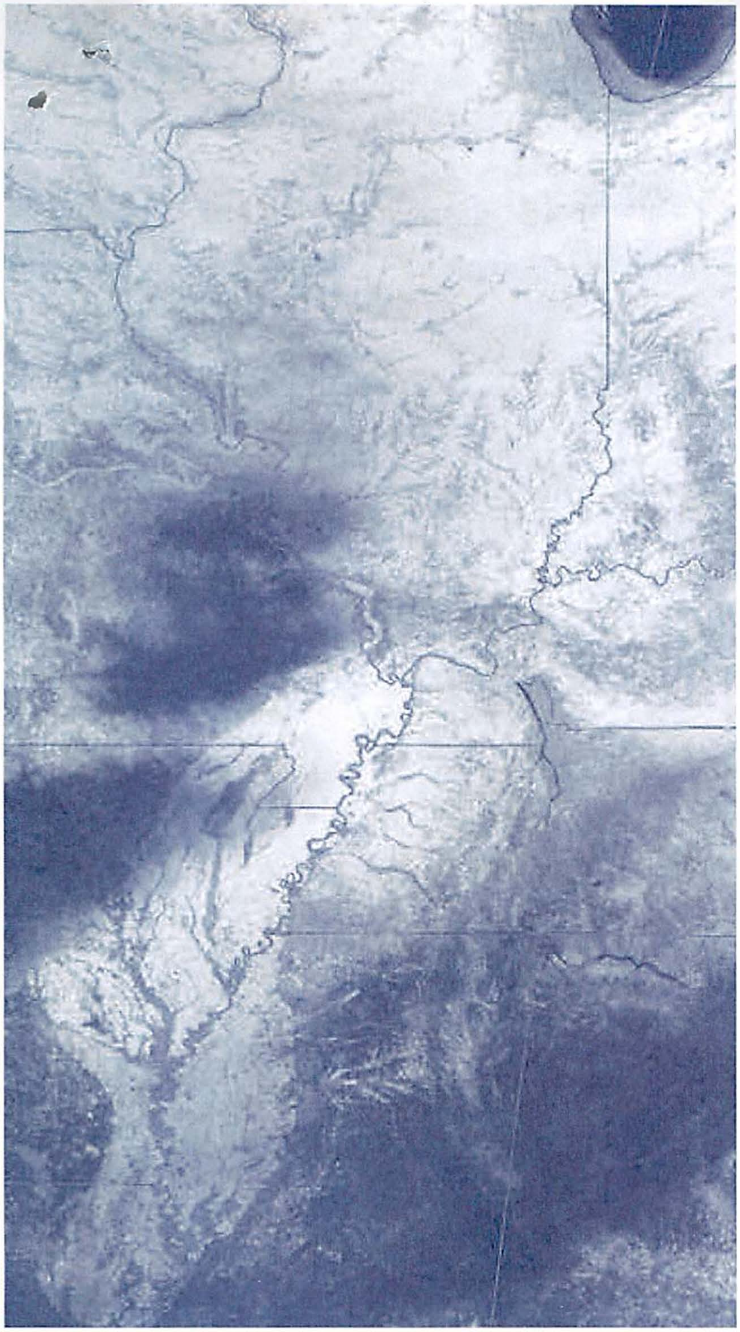
In addition to the lessons learned items being addressed by MISO, SPP, and the Joint Parties as part of the Regional Transfer Operating Committee MISO is continuing to evaluate our system's winter readiness and opportunities to improve. MISO's winter readiness process today includes such items as: 1) winter readiness workshop, fuel survey, winterization guidelines for resources that were all enhanced as part of the lessons learned from the 2014 polar vortex. MISO also has kicked-off discussions with stakeholders to evaluate resource availability and need to ensure energy is available every hour of the year. This discussion will continue in 2019.[5]

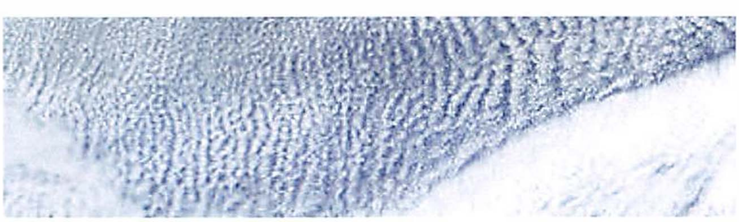
[5] MISO RAN Issues Statement Whitepaper: https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

FERC and NERC Staff Report July 2019

This report was prepared by the staff of the Federal Energy Regulatory Commission in consultation with staff from the North American Electric Reliability Corporation and its Regional Entities.

This report does not necessarily reflect the views of the Commission.





FERC and NERC Staff Report
July 2019

A.P.S.C. DOCKET NO 32953
APCo EX. NO. 53
Rabago-Cross

Nexant addressed uncertainty tied to measure impact by defining the program and portfolio scenarios using the Southern Company's DSM technology catalog, which was recently updated.

1.4.2 Rate Impacts

Energy-efficiency programs could cause electricity rates to rise faster than they would ordinarily. The noted uncertainties could result in lower than expected energy savings, without corresponding reductions in fixed program costs; therefore, adversely impacting rates. Market acceptance rates failing to materialize with forecasts, for example, would reduce saved energy and avoided cost benefits with fixed program management and reporting costs. If realized technology impacts prove less than estimated, impacts of all estimated costs for rebates, processing, marketing, and administration would remain, but with diminished supply-side cost savings. Rate impacts could, therefore, be more severe than those estimated in this study.

1.4.3 Differences from Prior Study

This energy efficiency potential assessment considers a significantly increased resolution of measure definitions and permutations building from more advanced energy simulation modeling and market research from prior Alabama Power potential assessments. The high-level portfolio, sector, and end-use level results remain largely unchanged with a subtle reduction in the estimate of energy-savings potential from the 2010 estimate of energy-efficiency potential. This reduction would be generally attributable to increased federal efficiency standards and building codes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Petition for determination of need for Okeechobee Clean Energy Center Unit 1 By Florida Power & Light Company	DOCKET NO. 150196-EI

ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA'S PREHEARING STATEMENT

The Environmental Confederation of Southwest Florida, Inc. ("ECOSWF"), by and through its undersigned counsel, and pursuant to Order No. PSC-15-0394-PCO-EI, Order Establishing Procedure, hereby submits its Prehearing Statement.

A. Appearances

Bradley Marshall
Alisa Coe
David Guest
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, Florida 32301

B. Witnesses

Witness	Subject Matter	Issue Nos.
Karl Rábago 62 Prospect Street White Plains, NY 10606	Lack of demonstration of need for Okeechobee power plant, reserve margin, loss of load probability, generation only reserve margin, system reliability, demand response, cost, and all other matters addressed in direct testimony.	1-7, Proposed Issues 8-12

All witnesses listed or presented by any other party or intervenor

Impeachment and rebuttal witnesses as needed

Any witness revealed through continuing discovery or other investigation

Authentication witnesses or witnesses necessary to lay a predicate for the admissibility of evidence as needed

EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, D.C. INTERNATIONAL

October 14, 2015

Carlotta Stauffer, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: DOCKET NO. 150196-EI
Petition for determination of need for Okeechobee Clean Energy Center Unit
By Florida Power & Light Company

Dear Ms. Stauffer,

On behalf of Intervenor, Environmental Confederation of Southwest Florida ("ECOSWF"), I have enclosed the testimony and exhibits of Karl Rábago. Please file these documents in Docket No. 150196-EI. Please contact me if there are any questions regarding this filing.

Sincerely,

/s/Bradley Marshall
Bradley Marshall
Florida Bar No. 0098008
Alisa Coe
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 14th day of October, 2015 via electronic mail on:

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/s/Bradley Marshall
Bradley Marshall, Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's	)	
Petition for Determination of Need for	)	DOCKET NO. 150196-EI
Okeechobee Clean Energy Center Unit 1	)	

TESTIMONY OF KARL R. RÁBAGO ON BEHALF OF THE ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA

October 14, 2015

INTRODUCTION

Q. **Please state your name, business name and address, and role with The Environmental Confederation of Southwest Florida.**

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a New York limited liability company, located at 62 Prospect Street, White Plains, New York. I appear here in my capacity as an expert witness on behalf of The Environmental Confederation of Southwest Florida.

Q. **Please summarize your experience and expertise in the field of electric utility regulation and the renewable energy field.**

A. I have worked for more than 25 years in the electricity industry and related fields. My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, and Director with AES Corporation, among others. A detailed resume is attached as Exhibit KRR-1.

Q. **Have you ever testified before the Florida Public Service Commission or other regulatory agencies?**

A. Yes. In the past three years, I have submitted testimony, comments, or presentations in proceedings in Florida, Virginia, New York, Hawai'i, Georgia, Minnesota, Michigan, Missouri, Louisiana, North Carolina, Kentucky, Arizona, Wisconsin, California, and the District of Columbia. A listing of my recent previous testimony is attached as Exhibit KRR-2.

Q. **What materials did you review in preparing this testimony?**

A. I reviewed applicable sections of the Florida Statutes and Administrative Rules, the Application of Florida Power & Light ("FPL" or "Company"), and other materials and information cited.

SUMMARY OF TESTIMONY

Q. **Please summarize your testimony in this matter.**

A. In this testimony, I review the Company's legal and regulatory requirements and how it addressed the standard of proof. I find that the Company has not met the requirements of the law because it has not demonstrated that the proposed Okeechobee power plant is needed. I specifically note that the Company has adopted a standard for when to propose new generation that is, in practice, a one-part test relating to a reserve margin percentage that is untested against actual impacts on system reliability and integrity, or adequacy of supply. I point out that the Company has created a system with outrageously low Loss of Load Probability ("LOLP") values, guaranteeing that customers are paying for an overbuilt system that unfairly burdens customers with unnecessary costs. I provide evidence drawn from the Company's application that deficiencies in the Application are not adequately addressed and materially impact the quality of the Application. I review the Company's evidence about forecasts of the drivers of need for generation capacity and show how the proposal in this Application is out of step with the Company's forecast data. Finally, I review the Company's assertions of potential harm associated with denial or delay in approval of this Application, and find that the Company has not substantiated these assertions with any data. Based on all this evidence and analysis, I recommend that the Commission deny the Company's Application. I recommend that the Commission direct the Company to take a hard look at system reliability and integrity as well as the costs of its generation construction plans prior to the submission of any subsequent application.

THE COMPANY'S RESPONSIBILITY UNDER THE LAW

Q. **What is your understanding of the Company's obligations under the Florida law in meeting its burden of production and persuasion in securing a determination of need for its**

Next Planned Generating Unit ("NPGU")?

A. Florida law requires that the Company submit competent and sufficient evidence to support a determination by the Florida Public Service Commission ("FPSC" or "Commission") that the proposed plant is needed. Under Florida Statute 403.519,[1] the evidence must enable the Commission to make a determination that adequately accounts for:

- "the need for electric system reliability and integrity,
- The need for adequate electricity at a reasonable cost,
- The need for fuel diversity and supply reliability,
- Whether the proposed plant is the most cost-effective alternative available, and
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available."[2]

Q. **What is the Company ultimately required to produce for review in this proceeding and what does it seek from the Commission?**

A. The Company is obligated to produce an application that justifies a determination of need, taking into account the factors for decision. The Company seeks a determination of need for its NPGU, what it calls the "Okeechobee Clean Energy Center Unit 1."

THE COMPANY'S APPLICATION FOR A DETERMINATION OF NEED

Q. **Have you reviewed the Company's application for a determination of need for its NPGU?**

A. Yes. Company witness Sim outlines the application in testimony supported and amplified by Company witnesses Kingston, Feldman, and Stubblefield. My testimony addresses issues raised by the testimony of all of these witnesses except Stubblefield.

[1] § 403.501, et seq. Florida Statutes.
[2] *Id.*

Q. **What does the Company propose in this application?**

A. Basically, the Company proposes to construct, own, and operate a 1,622 MW 3 x 1 Combined Cycle natural gas-fired greenfield power plant to be sited in the northeast corner of Okeechobee County.

Q. **How does this proposal compare with the plant addition contemplated in the Company's 2014 Ten Year Site Plan ("TYSP")?**

A. The proposed NPGU is 353 MW larger[3] than that contemplated in the 2014 TYSP—a 28% larger plant reflecting an increase in capacity of 5.5% per year in the planned unit size over the time from 2014 to 2019. FPL's 2014 TYSP is attached as Exhibit KRR-3N[4]. This significant increase in the already planned growth in generation stands in stark contrast to forecasted growth rates for customer population, load, and household income over the same period.

Q. **How does the current proposal compare with projections in 2013?**

A. According to Table 1 in the Commission's Order No. PSC-13-0505-PAA-EI in Docket No. 130198-EI, issued on October 28, 2013, this plant was not even needed just two years ago. In that case, the evidence was that the Company would not need any generation between 2016 and 2022. This order is attached as Exhibit KRR-4.

Q. **What is the foundation of the Company's basis for its application?**

A. The Company ultimately rests its entire application on the manner in which it employs what it terms the "three reliability criteria to project the timing and magnitude of its future resource needs." (Sim, p. 12, l.16 through p. 13, l.4) These criteria are the 20% minimum total Reserve Margin ("RM") test, the 10% minimum generation-only reserve margin, and the maximum loss of load probability standard of 0.1 day per year.

[3] Page 91 of the 2014 site plan shows a 1269 MW coming online in 2019.
[4] Composite Exhibit KRR-3 is a set of Florida Power and Light's 10-year site plans for 2001-2015.

Q. **How does the Company apply these tests?**

A. The Company's approach is quite simplistic. If, under the latest forecast, the Company expects not to meet any one of these criteria in a given year, then additional resources are deemed necessary in that year.

Q. **How does the Company forecast LOLP?**

A. It does not. As a result, the LOLP test really has no practical meaning in this application.

Q. **What factors drive LOLP?**

A. In general, LOLP is in practical terms, the risk of a blackout due to inadequate generation capacity. Specifically, LOLP measures the annual probability of loss of firm load events over a single year. LOLP improves, or is reduced, as the system operator diversifies the risk probability through the construction of more and smaller generating units, and through the modernization of the generation fleet.

Q. **What does this suggest about the LOLP that you would expect for FPL?**

A. As Company witness Kingston sets out in her testimony, the Company has been aggressively building new combined cycle generation since the year 2000 (Kingston, Exhibit JKK-2). This suggests that the Company system LOLP should have improved substantially over the past 15 years.

Q. **Does the Company provide any information about how the proposed NPGU impacts LOLP?**

A. Not in this Application. The Company provided LOLP calculations in response to a request from Staff in Docket No. 130199-EI, which I have attached as Composite Exhibit 5.[5] The Company provided data that showed that under its projections in place at the time of that Docket, it anticipated an LOLP value of 0.000387 days per year in 2015[6], and an LOLP of 0.007782 in

[5] Docket No. 130199-EI, Staff's Second Set of Interrogatories, Interrogatory No. 55, Including Affidavit of Sim and Attachment No. 1.

[6] Exhibit KRR-5A, Table marked as Plan without 10% Generation Only RM, LOLP for 2015

2018[7], on the eve of the intended operation of its NPGU.

Q. **What should the Commission understand from these numbers?**

A. The LOLP numbers are enormously lower than the LOLP standard of 0.1 days per year that the Company asserts is required to maintain system reliability:

- The 2015 number is 258 times smaller, or less than one half of one percent of the LOLP threshold set by the Company. The Company standard is the equivalent of one system outage day per year every ten years. In contrast, FPL's 0.000387 LOLP in 2015 is the equivalent of a blackout risk of 9.3 hours per 1,000 years. That risk is comparable to the risk of death caused by a falling meteor.[8]
- The LOLP rises to 0.007782 by 2018—still a massive difference from the 0.1 day LOLP standard the Company claims to use.
- An LOLP of 0.007782 is the equivalent of about 19 hours of outage per 100 years. These outage years do not include "acts of God," such as hurricanes. This number indicates that the proposed NPGU is not required in order to maintain system reliability or integrity.

Q. **Are you suggesting that the 0.1 day LOLP standard is inappropriate?**

A. Absolutely not. As reported in "The Economic Ramifications of Resource Adequacy White Paper" produced by Astrape Consulting for the Eastern Interconnection States' Planning Council and the National Association of Regulatory Utility Commissioners ("EISPC/NARUC"), attached as Exhibit KRR-7, the 0.1 day standard for Loss of Load Event ("LOLE") is common in North America, is generally used interchangeably with the LOLP term, and is generally applied in conjunction with reserve margins of 12% to 16%. What I am pointing out is that the Company applies its reliability criteria in such a way that it implements much higher reliability at much

[7] Exhibit KRR-5A, Table marked as Plan without 10% Generation Only RM, LOLP for 2018.

[8] Exhibit KRR-6 includes an estimate of the risk of being killed by a falling meteor.

higher cost than is required. As detailed in the EISPC/NARUC White Paper, economic analysis techniques for electric system reliability standard setting and evaluation have evolved considerably over the past several decades, offering important opportunities to reduce costs while maintaining system reliability and integrity.

Q. **How did the Company predict reserve margins would change during the period of 2013 through 2025 in Docket No. 130199-EI?**

A. The table in Exhibit KRR-3-M and provided by the Company in that case shows that when reserve margins near the 20% level, the Company proposes to add new generation. That is the position the Company takes in this Application as well. Overall system reserve margin drives the Company's proposals to build new capacity, without regard for actual system performance.

Q. **Where does the 20% RM test come from?**

A. The test is a legacy of a settlement reached in Commission Docket No. 981890-EU, and spelled out in Commission Order No. PSC-99-2507-S-EU, issued on December 22, 1999. Attached as Exhibit KRR-8.

Q. **Where does the 10% GRM test come from?**

A. I cannot tell from the application. I assume that it is a standard designed to ensure that at least half of the RM is met with generation assets, as opposed to interruptible load or other demand side resources. The Company points out that this factor is not significantly different in impact in light of the impact of the single-criteria standard and the forecasting that the 20% RM will not be met in 2019. (Sim, p. 16, l. 14-21)

Q. **Is the 10% GRM test, alone or in conjunction with the 20% RM test, still appropriate?**

A. This is an issue that should be investigated thoroughly by the Company in a public proceeding conducted by the Commission. Just as the Commission had to initiate the proceeding in Docket No. 981890-EU because of concerns about capacity adequacy, the evidence about outrageously low LOLP values and the steep increase in capacity additions and reliance on natural gas suggests that the Company is now out of control when it comes to power plant construction. A sequential review of the Company Ten Year Site Plans (TYSP) since 2000 demonstrates the way in which essential expansion and modernization of the generation fleet has transformed into an unnecessary and expensive building spree. I have attached these TYSP documents as Exhibits KRR-3A through KRR-3-O. In all, the factors suggesting a need to reexamine both the RM and GRM tests include:

- The increase in the rate of capacity additions since 2000, as I will describe.
- The dramatically low LOLP assessments for the FPL fleet.
- The potential for increased reliance on other generation in the Eastern Interconnection.
- The fact that 15 years has elapsed since the Commission undertook the inquiry in Docket No. 981890-EU.
- The dramatic improvements in load management, load control, and demand response that have occurred in the electricity industry over the past 15 years.
- The dramatic improvements in distributed generation and storage that have occurred over the past 15 years and the prospect of continued improvements in the economics and performance of these technologies (and other demand-side measures and technologies) when operating together, especially in microgrid configurations.
- The improvement and growth in analytical techniques to assess optimal and most economic reserve and reliability measures described in the EISPC/NARUC White Paper at Exhibit KRR-7.

Q. **Taken together, what do these factors demonstrate?**

A. As a whole, these factors and facts demonstrate that the standard of proof under Florida law is not satisfied merely by adherence to a 20% RM test or the 10% GRM test. Quite separately from the 20% RM test, the advances and availability of reliable demand response resources, above and beyond those selected through the FEECA process, suggests that the 10% GRM may be too high and too expensive to be economical.

Q. **Doesn't the Company's program of capacity expansion mean that customers save money?**

A. Not necessarily. The improved efficiency and incremental economics of modern generation must be tested against the added revenue requirements of an unamortized plant, increased amortization expense, and the customer net bill consequences of load building through measures like economic development rates and limits on energy efficiency improvements. In short, the Company should conduct an objective and quantitative assessment of the ratepayer impact measure of its generation construction program over the past fifteen years in order to honestly claim customer benefits.

Q. **How does the application of these tests ensure that the statutory requirement of system reliability and integrity is met?**

A. The Company submits no evidence to meet that requirement other than reciting the test. Specifically, the Company:

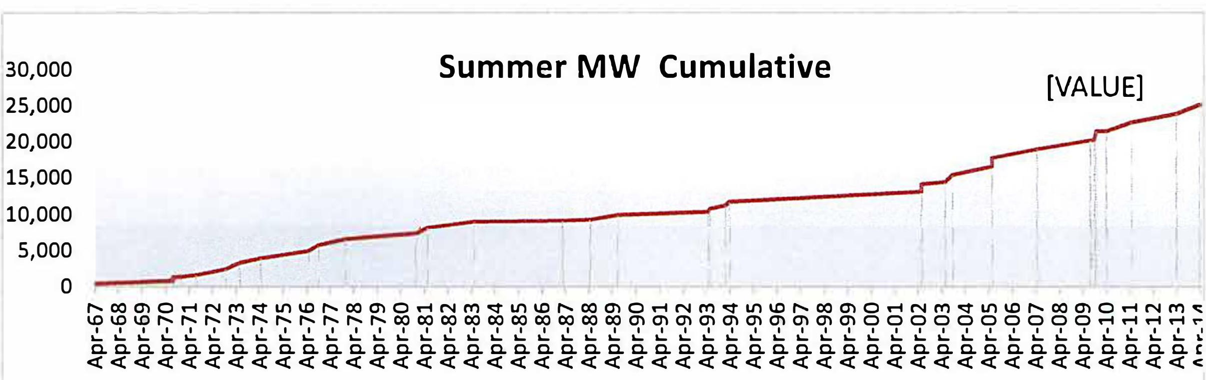
- Provides no evidence on the past, current, or forecasted LOLP,
- Provides no evidence of how the settlement-based 20% RM test ensures system reliability and integrity,
- Provides no foundation to explain the need for or value of the GRM test set at 10%, and
- Provides no explanation as to why not meeting any one of these tests is sufficient justification for requiring customers to pay for new Company-owned generation.

Q. **How would you characterize the Company's approach to this application based on your review of the testimony and supporting exhibits?**

A. The Company application is characterized by results-oriented arguments that use the reserve margin criteria as the vehicle for justifying a power plant building campaign. That is, rather than engage in a genuine search for the best alternatives to meet the need for energy services in a reliable and economic fashion, the Company appears to have recently decided that they would like to have another generating unit operating by 2019, and they built a case to support that conclusion. This campaign appears to have accelerated around the year 2000, when the 20% RM was adopted. The chart below, utilizing data from the Company Ten Year Site Plan, visually depicts this trend.

Figure 1. Summer Cumulative MW Capacity

Source: FPL Ten Year Site Plan 2015



Q. **Do you think that approach is problematic?**

A. Yes. I believe it is inconsistent with the spirit of the requirements of Florida Statute 403.519 to seek out only the most economic and beneficial resources when there is demonstrated need for those resources. While this might be beneficial to the Company's shareholders as long as the Commission approves such applications, the result is likely excess capacity that imposes long-term burdens on customers and the electricity market in Florida.

Q. **How do you believe the Commission should evaluate the Company's assertions of**

the need for more generation to support system reliability and integrity?

A. The Company enjoys a monopoly position as a provider of electricity in its service territory at a rate of return that provides substantial, almost guaranteed returns to investors. Customers end up paying for the Company's investments whether they are needed or not, so the Commission has the responsibility of ensuring that the Company has fully demonstrated the need for every investment in capacity.

Q. **Does the 20% Reserve Margin standard ensure that generation capacity is needed?**

A. No. The evidence in this case is that slavish adherence to the 20% Reserve Margin has, in effect, a single-factor criterion that has resulted in costly and unnecessary overbuilding of the Company system. This Application demonstrates that overbuilding. The 20% Reserve Margin adopted by Commission settlement may have been the right solution at a time when it appeared that the Company capacity planning and construction was not keeping pace with load growth and contingencies in its service territory. But now, the 20% Reserve Margin, unbalanced by a consideration of actual impacts on reliability, is excessive and unnecessarily expensive.

THE COMPANY FORECASTS OF GROWTH AND NEED

Q. **How does the proposed NPGU size compare with forecasts of growth and need?**

A. Company witness Feldman sets out the forecasting process. He explains that in order to forecast customer growth, net energy for load, and peak demand, the Company looks at forecasts of pollution, economic conditions, the weather, and codes and standards. (Feldman, p. 8, l. 9-19)

Q. **What rate does the Company forecast for customer growth?**

A. The Company forecasts the number of customers to grow by 1.3%, on average, between 2015 and 2024. (Feldman, p. 10, l. 1-3).

Q. **What rate of household disposable income growth does the Company assume during the 2015-2024 period?**

A. The Company assumes a 2% average annual growth rate in household disposable income during that period. (Feldman, p. 12, l. 10).

Q. **What rate of summer peak demand growth does the Company expect during the period 2014-2024?**

A. The Company expects summer peak demand growth at a rate of 1.6% per year during this period. (Feldman, p. 17, l. 23).

Q. **What is the probability and magnitude of potential deviation from this expected rate of demand growth under the Company's risk-adjusted procedure?**

A. The Company estimates that there is a 25% chance that the summer peak demand could grow at a rate of 2.1% per year, instead of 1.6%. (Feldman, p. 20, l. 12).

Q. **What is the probability and magnitude of potential downward deviation from the expected rate of demand growth under the Company's risk-adjusted procedure?**

A. There is a 75% chance that the growth in demand will be less than the base forecast, but the Company does not report the magnitude of that potential deviation. (Feldman, p. 20, l. 1-4)

Q. **Does the risk-adjusted analysis suggest the potential for over-building of capacity?**

A. Yes. The analysis suggests a 25% chance that demand could be 1,143 MW higher in 2019 than currently forecast. If the 75% probability that demand will be lower has equivalent impact, the demand requirement underpinning this application disappears entirely.

Q. **Does this suggest that the Company should do nothing?**

A. Absolutely not. Given the significant probability that the current NPGU will represent overbuilding, it would be reasonable in light of the Florida statutory directives to evaluate approaches to mitigate this risk with a more modular and just-in-time approach to meeting demand.

Q. **The Company forecast seems to indicate that all major drivers of demand and demand itself are likely to grow at an average rate of 2% or less during the period of 2015 -**

2024. What is the rate of capacity increases the Company has implemented?

A. The Company has increased capacity at a rate of about 5% average annual growth since 2000, when the Reserve Margin settlement order was issued. The NPGU in this Application would continue that trend of growth.

Q. **Witness Sim asserts that the Company undertook an "extensive evaluation process." (Sim, p. 7, l. 5). Do you agree?**

A. The extensive evaluation process only describes how the preferred plant design was chosen. After reviewing the evaluation process, I come to the conclusion that the entire process was ultimately designed to select the chosen NPGU because that solution is the one that meets the reserve margin requirements. That is, reserve margin requirements, and not the factors cited in the Florida Statute and Rules seem to be deciding how generation is added to the FPL system.

Q. **How does the application address the issue of fuel diversity?**

A. The NPGU will not increase fuel diversity. (Sim, p. 10, l. 4). In fact the NPGU will increase the Company's already extensive reliance on natural gas as a fuel. The risk of this excessive dependence on natural gas is significant for customers, who bear any and all fuel price risk. The Company asserts that other initiatives will reduce the risks of this reduction in fuel diversity, but does not quantify the added risks to which customers are exposed compared to a no-plant alternative. Of course, the gas price volatility risk benefits of the other mitigation measures will be far more effective if 1,622 MW of natural gas generation is not added to the fleet in 2019.

Q. **Does the Company's dependence on natural gas stand out as excessive?**

A. Yes. According to Schedule 6.2 (attached as Exhibit KRR-3-O) of the Company's 2015 Ten Year Site Plan, the proposed NPGU in this Application would increase the Company's dependence to nearly 70% of total generating capacity. As a whole, Florida was recently singled out as the State most at risk for overreliance on natural gas in a study by the Union of Concerned

Scientists.[9]

Q. **Does the Company address efficiency and resulting environmental benefits?**

A. Company witness Kingston states that the NPGU will be 35% more fuel efficient than a conventional steam plant of the same size. (Kingston, p. 9, l. 20-22) However, there is no serious proposal for the construction of a conventional steam plant. The proposed NPGU will perform at about the same level of efficiency as other combined cycle plants of recent vintage, similarly configured. The Company does not directly report gross emissions in tons from the proposed NPGU. (Kingston, p. 17-18) The Company asserts that the plant will improve the system heat rate, but offers no quantitative data. (Kingston, p. 9, l. 22-23)

Q. **How does the application address the option to deploy demand side resources ("DSM") to meet the need?**

A. The Company evaluates the DSM resource option solely for its ability to meet *all* of the increase in forecasted need. This approach is unrealistic, does not consider matching an increase in demand side resources coupled with a smaller NPGU. While I understand that additional demand side resources would not clear the RIM test hurdle in the recent FEECA proceeding, it is important to note that the proposed new plant in this application will, in fact, increase rates and costs for all ratepayers. Options not considered include sufficient demand side resources to defer the NPGU for a single year, for example. Instead, the Company constructs a hyperbolic hypothetical in which 800 MW of new DSM must be obtained solely through increases in the residential air conditioning control program.

Q. **How does the application square the fact that the proposed NPGU is significantly larger than the identified need in 2019?**

A. As applied by the Company, the reserve margin tests appear to serve only as a floor for

[9] "Rating the States on Their Risk of Natural Gas Overreliance," Union of Concerned Scientists (October 2015). Available at www.ucsusa.org/naturalgasoverreliance. Attached as Exhibit KRR-9.

resource sizing. In this proposal, the maximum need in 2019 is 1,052 MW. And yet the Company is proposing 1,622 MW. This seriously tests the common sense definition of "need," and seems to confirm that the Company is primarily focused on building rate base.

Q. **How does the Company evaluate renewable utility scale solar photovoltaic generation as a resource?**

A. First, as with DSM, the Company only evaluated the solar PV option for its ability "to supply all, or a substantial portion, of the needed 1,052 firm MW of Summer capacity." (Sim, p. 23, l. 7-10). The Company also finds too many other uncertainties associated with development of solar PV that could be resolved by the 1st quarter of 2015.

Q. **Where did the test of the 1st quarter of 2015 come from?**

A. That is the date on which the Company felt it had to commit to its decision to pursue a natural gas-fired self-build option. (Sim, p. 23, l. 10-12). The Company does not evaluate the solar option from the perspective of the time frame required to develop that option.

Q. **Does the Company approach impact the offering of competitive bids?**

A. Yes. As detailed by Company witness Sim, the fact that the Company uses such a large, self-build NPGU size has a significant impact on dampening participation by non-utility bidders. (Sim, p. 33, l. 15-18).

Q. **What does the Company say about the potential consequences of delay in the construction of the proposed NPGU?**

A. Company witnesses Sim and Kingston both address the potential for delay in securing a determination of need in this proceeding. Witness Sim suggests that FPL customers "will face significant adverse consequences related to either system reliability or the cost of electricity." (Sim, p. 37, l. 6-8). Witness Kingston states that delay would defer operation "necessary to maintain system reliability and provide an efficient reliable generating unit that will contribute to ensuring customers have adequate electricity at a reasonable cost. In addition, it would result in a higher system heat rate and lower customer fuel savings than customers would enjoy if the unit were constructed on time."

Q. **Does the Company provide any quantitative analysis or information to support its assertions of negative consequences?**

A. No. In my opinion, the Company witnesses could quantify net heat rate savings, fuel savings, reliability benefits, LOLP impacts, and other factors to support their assertions. The lack of this evidence weakens their assertion of need.

FINDINGS AND CONCLUSIONS

Q. **What are your findings in this case?**

A. My findings can be summarized as follows:

- The Company reliance on the 20% Reserve Margin criteria drives this application, and, in fact, has driven a substantial amount of generation construction for the Company.
- The Company reliance on the 10% generation-only reserve margin is also a significant factor in the Company's justifications for building new capacity.
- The reliability standard of a maximum loss-of-load probability (LOLP) of 0.1 day per year is not a significant driver of generation planning and proposals. The Company does not quantitatively address the reliability status of its system or the impacts of its proposal on reliability.
- The Company rate of historic and proposed growth in power plant construction significantly outstrips the forecasted rate of growth in population, household income, and electricity consumption.
- The high rate of plant construction, in large plant unit sizes, appears to have the effect of almost eliminating independent power plant development in the Company's

service territory.

- The Company pays little or no attention to the risk of overbuilding, despite the potential economic impacts on customers.
- The Company has not quantified either the asserted risks or the potential benefits of delay in building the NPGU.

Q. **What do you conclude based on your findings?**

A. In light of the statutory background described above, and the information submitted in the Company's application, I conclude that the Company's application for a determination of need for its NPGU is materially deficient in the following respects:

- The Company's application does not adequately establish the need for the NPGU to maintain system reliability and integrity.
- The Company proposal does not consider the risks and impacts of overbuilding, and therefore fails to properly address the requirement for adequate and affordable electricity service.
- The Company proposal does not improve and in fact worsens the Company position in terms of fuel diversity, and exposes customers to greater fuel supply risk and costs in the future.
- By failing to consider the potential for overbuilding, the Company constrains its examination of alternative methods to meet the demand for energy services, and therefore has not demonstrated that its proposal is the most cost effective alternative.

RECOMMENDATIONS

Q. **In light of your findings and conclusions, do you offer any recommendation to the Commission?**

A. I recommend that the Commission deny the Company's application for a determination of need for its NPGU.

Q. **Do you have any further recommendations?**

A. Yes. I recommend that the Commission direct the Company to ensure that in any subsequent application for need filing, the Company fully and quantitatively analyze the impact on system reliability and integrity that drives the application. In particular, the Company should report the current state of the LOLP assessment and how that metric is impacted by any NPGU.

Q. **Do you have any recommendations regarding analysis of resource options in any subsequent application by the Company?**

A. Yes. The Commission should direct the Company to explore ways to increase the reliance on demand side resources and third-party owned generation resources as part of an effort to diversify risk to customers. In particular, the Commission should direct the Company to examine reliability issues in light of the Port Everglades Unit 5 plant and planned capacity additions by other utilities operating in the Florida peninsular system. In addition, and above and beyond the FEECA process, the Commission should direct the Company to explore "extreme" or "fast response" demand response resources specifically designed to provide reliability support. The Company should compare the short- and long-term costs of these options against any self-build power plant proposals. Finally, the Commission should direct the Company to quantitatively assess in any future application the risks of over-building in terms of costs to customers, potential stranding of investments, and impacts on demand-side and third-party owned resources.

Q. **Does this conclude your testimony?**

A. Yes.

Standing witnesses as needed

C. Prefiled Exhibits

ECOSWF will sponsor the direct exhibits as set out below. However, ECOSWF reserves the right to use other exhibits during cross examination of any other party's or intervenor's witnesses, and will file a notice in accordance with the orders governing procedure identifying any documents that Florida Power & Light ("FPL") claims to be confidential which ECOSWF may use during cross examination.

Exh. Number	Sponsoring Witness	Description
KRR-1	Karl Rábago	Resume of Karl Rábago
KRR-2	Karl Rábago	Table of Previous Testimony by Karl Rábago
KRR-3-A	Karl Rábago	FPL 2001-2010 Ten Year Site Plan
KRR-3-B	Karl Rábago	FPL 2002-2011 Ten Year Site Plan
KRR-3-C	Karl Rábago	FPL 2003-2012 Ten Year Site Plan
KRR-3-D	Karl Rábago	FPL 2004-2013 Ten Year Site Plan
KRR-3-E	Karl Rábago	FPL 2005-2014 Ten Year Site Plan
KRR-3-F	Karl Rábago	FPL 2006-2015 Ten Year Site Plan
KRR-3-G	Karl Rábago	FPL 2007-2016 Ten Year Site Plan
KRR-3-H	Karl Rábago	FPL 2008-2017 Ten Year Site Plan
KRR-3-I	Karl Rábago	FPL 2009-2018 Ten Year Site Plan
KRR-3-J	Karl Rábago	FPL 2010-2019 Ten Year Site Plan
KRR-3-K	Karl Rábago	FPL 2011-2020 Ten Year Site Plan
KRR-3-L	Karl Rábago	FPL 2012-2021 Ten Year Site Plan
KRR-3-M	Karl Rábago	FPL 2013-2022 Ten Year Site Plan

KRR-3-N	Karl Rábago	FPL 2014-2023 Ten Year Site Plan
KRR-3-O	Karl Rábago	FPL 2015-2024 Ten Year Site plan
KRR-4	Karl Rábago	Order No. PSC-13-0505-PAA-EI, In re: Petition for Prudence Determination Regarding New Pipeline System by Florida Power & Light Company.
KRR-5-A	Karl Rábago	FPL LOLP Table with and without 10% Generation Only Reserve Margin from Docket No. 130199-EI
KRR-5-B	Karl Rábago	Affidavit of Steven R. Sim
KRR-5-C	Karl Rábago	Interrogatory Answer from Docket No. 130199-EI
KRR-6	Karl Rábago	Chance of Meteor Strike
KRR-7	Karl Rábago	The Economic Ramifications of Resource Adequacy, January 2013, Eastern Interconnection States' Planning Council
KRR-8	Karl Rábago	Order No. PSC-99-2507-S-EU, In re: Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida

All exhibits listed or introduced into evidence by any other party or intervenor

Standing documents as needed

Impeachment exhibits

Rebuttal exhibits

Exhibits determined necessary by ongoing discovery

All deposition transcripts, and exhibits attached to depositions

All documents produced in discovery

Blow ups or reproductions of any exhibit

Demonstrative exhibits

All pleadings, orders, interrogatory answers, or other filings

All document or data needed to demonstrate the admissibility of exhibits or expert opinion

Maps and summary exhibits

D. Statement of Basic Position

There is no need for the proposed Okeechobee Power plant pursuant to 403.519(3), Florida Statutes. The proposed plant will lead to increases in customers' bills which are several times the increases that were contemplated with high energy efficiency goals in the FEECA proceedings. There is no need for these increases, as FPL's generating system is already over-built. FPL's own reliability projections show that system reliability will in no way be compromised by saving over 1 billion dollars of ratepayer money by not building another unneeded power plant. Instead of investing in Florida's clean energy future, FPL wants to double-down on natural gas, a fuel which FPL already over-relies on.

FPL advocates for special treatment in this proceeding, adding a generation-only reserve margin reliability criterion which no other utility gets, in order to justify additional over-building. FPL argues that this additional criterion because energy efficiency and demand response are not reliable, an argument which is demonstrably false.

FPL is likely to point to the January 11, 2010 high load event to show that high reserves are needed. The weather on January 11, 2010 was unprecedented. FPL sold Duke 500 MW during the height of the event, and was still able to meet all firm load. People lose power all the time from transmission wires or substations being down, often due to weather. During a hurricane, people can lose power for several days due to transmission failures. We do not overbuild our transmission lines to the extent that they can withstand a Category 5 hurricane, and neither should we overbuild our generating system to withstand any possible event. Extreme weather can cause power disruptions. Solely focusing on whether there is enough generating capacity for all extreme weather events is not a helpful exercise, because even if there is enough generating capacity in a Category 5 hurricane to meet all demand, having that capacity is not useful if the power lines are down. Nor should we be trying to build our electric system to withstand such a weather event. The cost simply outweighs the benefit. When driving down the highway, people do not pay to have a chase car full of parts and mechanics follow them in case they break down. In the unlikely event their car breaks down, they simply go through the inconvenience of calling a tow truck, and having a mechanic fix the car. Similarly, in the event of an extreme weather event like the one that took place on January 11, 2010, some small risk of failure to meet all firm demand, a risk that is far smaller than that of a hurricane taking down transmission lines for more than a day, is acceptable if the cost is too much. The cost of the proposed plant is too much for FPL customers. FPL is overbuilding its generating capacity in order to guarantee its own profits, at the cost of a small fortune to its customers. The cost-benefit analysis of building generation to withstand freak weather events should be treated the same as the cost-benefit analysis of over-building transmission to withstand hurricanes. Demand response is the true safety valve for freak weather events. To the extent FPL has any additional need to cover peak load requirements, FPL should expand its investments in energy efficiency, clean energy, and demand response and load management programs.

E. <u>Statement of Issues and Positions</u>

<u>ISSUE 1</u>: Is there a need for the proposed Okeechobee Clean Energy Center Unit 1, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(3), Florida Statutes?

POSITION: No. FPL's system will meet appropriate reliability and integrity standards without the proposed unit.

<u>ISSUE 2</u>: Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to Florida Power & Light, which might mitigate the need for the proposed Okeechobee Clean Energy Center Unit 1?

POSITION: Yes, renewable energy and conservation measures could obviate whatever need would be met by the proposed unit.

ISSUE 3: Is there a need for the proposed Okeechobee Clean Energy Center Unit 1, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519(3), Florida Statutes?

POSITION: No. The unnecessary unit will simply add an unnecessary cost to FPL customers.

ISSUE 4: Is there a need for the proposed Okeechobee Clean Energy Center Unit 1, taking into account the need for fuel diversity, as this criterion is used in Section 403.519(3), Florida Statutes?

POSITION: No. The proposed unit will increase FPL's over-reliance on natural gas when FPL should be investing in clean energy to diversify its fuel portfolio.

ISSUE 5: Will the proposed Okeechobee Clean Energy Center Unit 1 provide the most cost-effective alternative, as this criterion is used in Section 403.519(3), Florida Statutes?

POSITION: No. Energy efficiency, clean energy, demand response and load management, and not over-building are more cost-effective alternatives.

ISSUE 6: Based on the resolution of the foregoing issues, should the Commission grant Florida Power & Light's petition to determine the need for the proposed Okeechobee Clean Energy Center Unit 1?

POSITION: No. The Commission should deny the petition.

ISSUE 7: Should this docket be closed?

POSITION: Yes.

ECOSWF PROPOSED ISSUE 8:

What reserve margin criterion should be used to determine FPL's need?

POSITION: A 15% reserve margin should be applied, because coupled with the Loss of Load Probability criterion, system reliability is ensured.

ECOSWF PROPOSED ISSUE 9:

Should the Commission apply reserve margin criterion to FPL that are not applied to other utilities?

POSITION: No. The Commission should reject FPL's request to add the generation-only reserve criterion.

ECOSWF PROPOSED ISSUE 10:

Is demand response significantly cheaper than new power plants?

POSITION: Yes. As a consequence, FPL should be expanding demand response in order to maintain reliability during freak weather events, not spending ratepayer money on an unneeded power plant.

ECOSWF PROPOSED ISSUE 11:

Has the reduction in payments by FPL to customers for participation in demand response programs artificially reduced demand for demand response?

POSITION: Yes. By reducing payments, FPL has artificially reduced the number of customers who would volunteer to participate in demand response programs.

ECOSWF PROPOSED ISSUE 12:

Should FPL follow the 15% reserve margin recommended by the North American Electric Reliability Corporation?

POSITION: Yes. The 15% reserve margin, coupled with the Loss of Load Probability criterion, ensures adequate reliability.

F. Stipulated Issues

ECOSWF has not stipulated to any issues at this time.

G. Pending Motions or Other Matters

ECOSWF has no pending motions or other matters at this time.

H. Pending Requests or Claims for Confidentiality

ECOSWF has no pending confidentiality requests or claims.

I. Objections to Witness' Qualifications as an Expert

None at this time.

J. <u>Compliance with Order Establishing Procedure</u>

ECOSWF has complied with all applicable requirements of the order establishing procedure in this docket.

Respectfully submitted this 3rd day of November, 2015.

/s/ Bradley Marshall
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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 3rd day of November, 2015 via electronic mail on:

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