TAG Meeting
April 16, 2013

NCEMC Office

Raleigh, NC

TAG Meeting Agenda

1. Administrative Items – Rich Wodyka
2. FERC Order No. 1000 - Rule on Transmission Planning – Sam Waters
3. 2013 Study Activities and Study Scope Update – Mark Byrd
4. 2012 NCTPC – PJM Joint Interregional Reliability Study Report – Orvane Piper
5. Regional Studies Update – Bob Pierce
6. 2013 TAG Work Plan – Rich Wodyka
7. TAG Open Forum – Rich Wodyka

FERC Order No. 1000 Rule on Transmission Planning and Cost Allocation Compliance Update

Sam Waters – Duke Energy

on behalf of the North Carolina Transmission Planning Collaborative

Regional Compliance Update

- Duke Energy Carolinas and Progress Energy Carolinas submitted the Order No. 1000 regional compliance filing on October 11, 2012.
- FERC issued an order on February 21, 2013 finding that due to the merger of Duke and Progress, Duke and Progress are no longer separate transmission providers for purposes of Order No. 1000 compliance and therefore the NCTPC no longer qualified as an Order No. 1000 transmission planning region.

Regional Compliance Update (cont.)

- Duke-Progress submitted a request for rehearing/ clarification of the FERC order.
  - Rehearing request – Requested that FERC reconsider their finding and find that Duke and Progress are separate transmission providers.
  - Clarification request – If FERC does not find that Duke and Progress are separate transmission providers then FERC should clarify that Duke and Progress have a single footprint for Order No. 1000 purposes.

Regional Compliance Update (cont.)

- Rehearing/Clarification request responded to LS Power's request for clarification of the FERC order requesting FERC determine that a Duke-Progress transmission project would be a regional project, instead of a local project.
- NCEMC submitted an Answer to the LS Power filing:
  - Requested that FERC reject the LS Power request for clarification. A Duke-Progress project should be considered a local project.
  - If FERC rejects the Duke-Progress request for rehearing of the order, NCEMC stated that the NCTPC process should continue to be used for local transmission planning.

Regional Compliance Update (cont.)

- Based on the FERC order, Duke is working to join the SERTP region.
- Duke's revised regional compliance proposal will include the following:
  - Preservation of the NCTPC as a local transmission planning process
  - Use of the SERTP as the regional transmission planning process
- Schedule for revised regional compliance filing
  - April 23: Release draft Tariff for stakeholder review/comment
  - May 7: Stakeholders provide comments on the draft
  - May 22: Duke-Progress submit filing

Interregional Compliance Update

- SERTP Sponsors will be submitting their interregional compliance filings
- Stakeholder input to the SERTP interregional strawman should be provided to the SERTP
- Following slides are from the SERTP April 10th meeting where the interregional strawman was discussed

SERTP Interim Meeting

October 17th

FERC Order 1000 Discussion

“SERTP”

Background

Order 1000

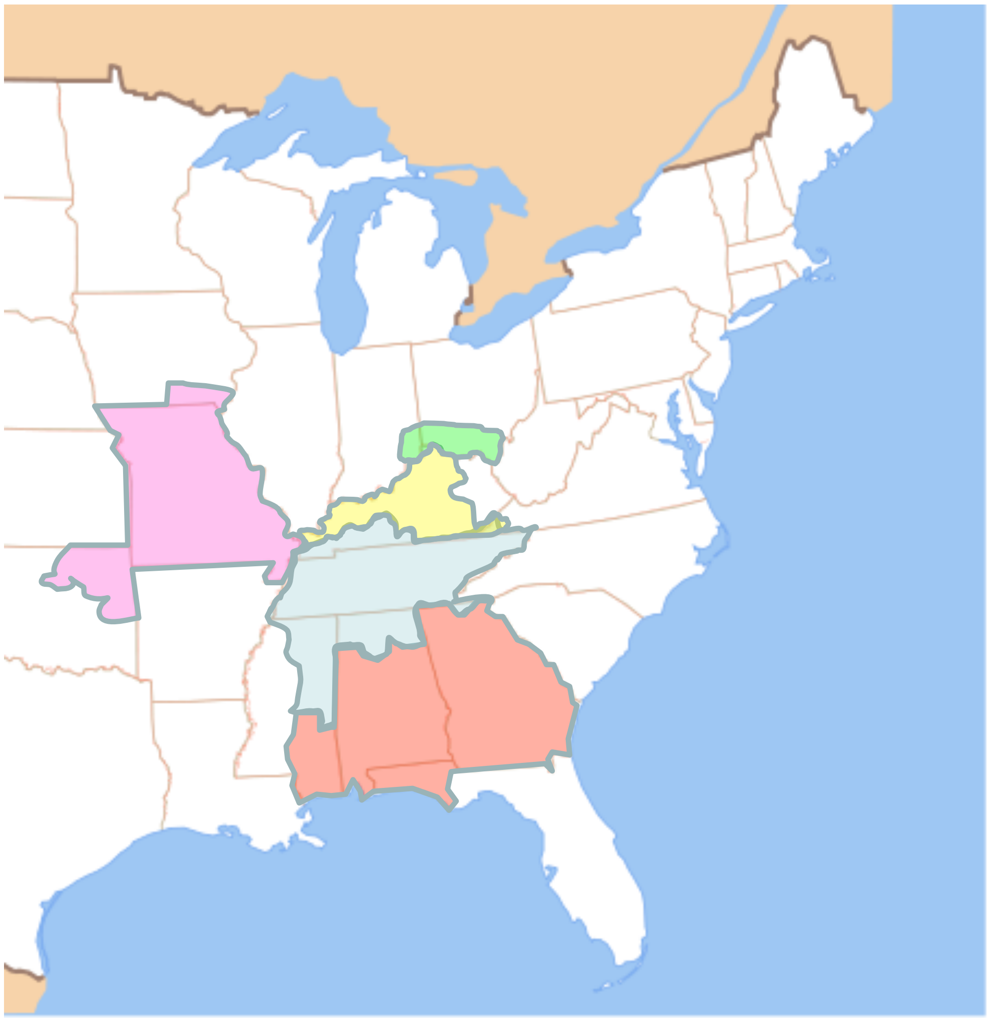
- Background
  - The Southeastern Regional Transmission Planning ("SERTP") Process was formed in 2007 by:
    - Dalton Utilities ("Dalton")
    - Georgia Transmission Corporation ("GTC")
    - Municipal Electric Authority of Georgia ("MEAG")
    - PowerSouth Electric Cooperative ("PowerSouth")
    - South Mississippi Electric Power Association ("SMEPA")
    - Southern Companies ("Southern")

Order 1000

- Background
  - Recently, the SERTP has received an extension of time to submit an Order 1000 compliance filing that expands the SERTP region to include the following entities:
    - Associated Electric Cooperative, Inc. (“AECI”)
    - Louisville Gas & Electric and Kentucky Utilities (“LGE / KU”)
    - Ohio Valley Electric Corporation (“OVEC”)
    - Tennessee Valley Authority (“TVA”)
  - Motion for Extension
    - FERC granted the 120 day extension on September 6th, 2012 extending the filing due date until February 8, 2013

Southeastern Regional TRANSMISSION PLANNING

SERTP Sponsors



- Original SERTP
  - Southern
  - GTC
  - MEAG
  - Dalton
  - PowerSouth
  - SMEPA
- TVA
- AECI
- LG&E / KU
- OVEC

SERTP Sponsors

- Associated Electric Cooperative, Inc.
  - ❖ AECI is owned by and provides wholesale electricity to six G&Ts who serve 51 Distribution Cooperatives with a combined service area covering 90,414 square miles.
    - Headquarters: Springfield, MO
    - Miles of Transmission Line ≈ 9,650
    - Historical Peak Demand ≈ 4,495
    - Number of Member Consumers ≈ 875,000
    - States
      - Missouri
      - Northeast Oklahoma
      - Southeast Iowa

SERTP Sponsors

- Dalton Utilities
  - ❖Established in 1889, DU provides electric, natural gas, water, wastewater, stormwater & telecommunications services to approximately 77,000 customers in Dalton, GA and five surrounding counties.
    - Headquarters: Dalton, GA
    - Miles of Transmission Line ≈ 305
    - Historical Peak Demand ≈ 272 MW
    - Number of Electric Consumers ≈ 18,200
    - States
      - – Georgia

SERTP Sponsors

- Georgia Transmission Corporation

❖ GTC is an electric membership corporation that provides transmission service to 39 retail distribution cooperative members in the state of Georgia.

  - Headquarters: Tucker, GA
  - Formed in 1997 with restructuring of Oglethorpe Power Corporation
  - Miles of Transmission Line ≈ 3,100
  - Historical Peak Demand ≈ 9,300 MW
  - Members serve approximately 4 million people

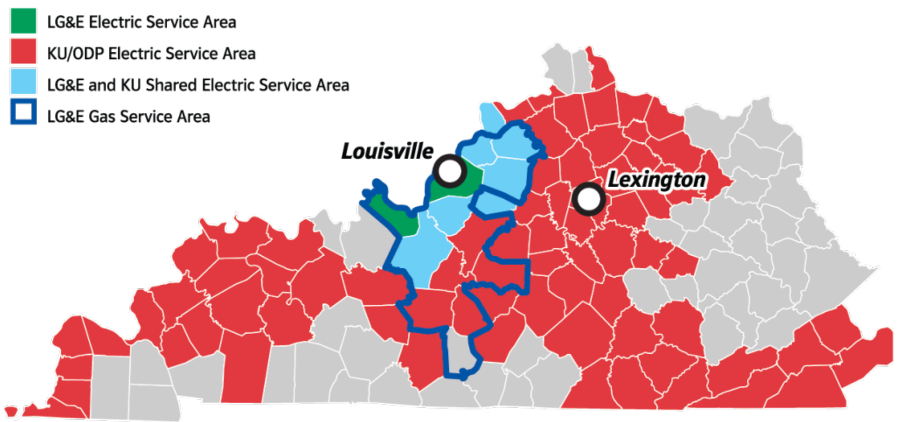
Southeastern Regional TRANSMISSION PLANNING

SERTP Sponsors

- LG&E / KU

❖ Louisville Gas & Electric and Kentucky Utilities are vertically integrated companies that serve two-thirds of the counties in Kentucky and parts of Virginia.

- Headquarters
  - Louisville, Kentucky
- Miles of Transmission Line
  - ~5000
- Historical Peak Demand
  - 7,175 MW
- Number of Customers
  - 943,000 (Electricity)
  - 321,000 (Natural Gas)
- States
  - Kentucky
  - Virginia



SERTP Sponsors

- MEAG Power
  - ❖ A public corporation and an instrumentality of the State of Georgia providing G&T service to 48 cities and one county.
    - Headquarters: Atlanta, GA
    - Miles of Transmission Line ≈ 1320
    - Historical Peak Demand ≈ 2200 MW
    - Number of City and County Consumers ≈ 310,000
    - States
      - – Georgia

SERTP Sponsors

- OVEC
  - ❖OVEC, and its wholly owned subsidiary Indiana-Kentucky Electric Corporation (IKEC), owns and operates a 345kV transmission system across three states; Ohio, Kentucky, and Indiana.
    - Headquarters: Piketon, OH
    - Miles of Transmission Line ≈ 660
    - Peak Generation ≈ 2,200 MW
    - Sell Only to Sponsoring Utilities
      - – By contract, owners are entitled to all generation
      - – DOE facility in Balancing Area; Supplied by off-system sources

Southeastern Regional TRANSMISSION PLANNING

SERTP Sponsors

- PowerSouth
  - ❖PowerSouth is a G&T Cooperative consisting of 16 Distribution Cooperatives and 4 Municipal systems with a total service area of approximately 31,000 square miles.
    - Headquarters: Andalusia, Alabama
    - Miles of Transmission Line ≈ 2,240
    - Historical Peak ≈ 2,400 MW
    - Number of Customers ≈ 418,000
    - States
      - – Alabama
      - – Florida

SERTP Sponsors

- Southern Company
  - ❖Southern Company, which includes four retail operating companies, provides electric service across 120,000 square miles in four states.
    - Headquarters: Atlanta, GA
    - Miles of Transmission Line ≈ 27,000
    - Historical Peak Demand ≈ 38,500 MW
    - Number of Customers ≈ 4,400,000
    - States
      - Alabama (Alabama Power Company)
      - Georgia (Georgia Power Company)
      - Mississippi (Mississippi Power Company)
      - Florida (Gulf Power Company)

Southeastern Regional TRANSMISSION PLANNING

SERTP Sponsors

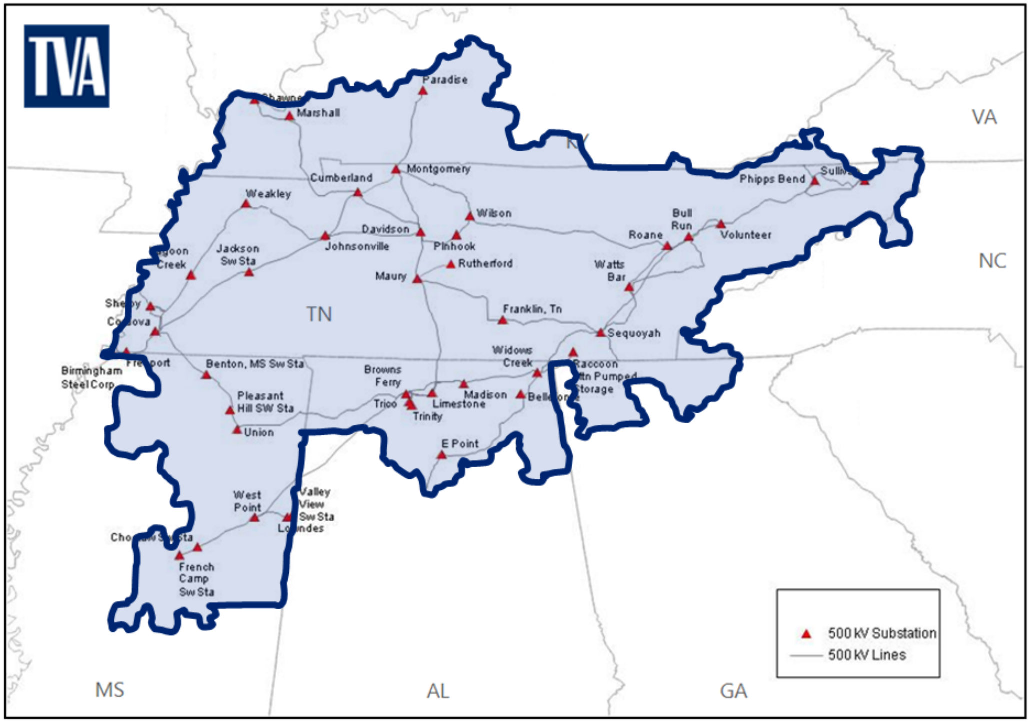
- SMEPA
  - ❖ South Mississippi Electric Power Association is a rural electric cooperative that generates, transmits and sells power to 11 member distribution cooperatives in Mississippi.
    - Headquarters: Hattiesburg, MS
    - Miles of Transmission Line ≈ 1,741
    - Historical Peak Demand ≈ 1507 MW
    - Number of Customers ≈ 410,000 homes/businesses
    - States
      - – Mississippi

SERTP Sponsors

- Tennessee Valley Authority (TVA)

❖ Corporation owned by the U.S. government, provides electricity for 9 million people across 80,000 square miles in parts of seven southeastern states.

- Headquarters
  - Knoxville, Tennessee
- Miles of Transmission Line
  - ~16,000 (2,500 - 500kV)
- Historical Peak Demand
  - 33,482 MW
- Number of Customers
  - 155 distributors
  - 58 direct served customers
- States
  - Alabama
  - Georgia
  - Kentucky
  - Mississippi
  - North Carolina
  - Tennessee
  - Virginia



FERC Order 1000

Stakeholder Discussion

October 17th, 2012

FERC Order 1000

High-Level Overview

Order 890

- Order 890
  - Transmission Planning Principles
    - Coordination
    - Openness
    - Transparency
    - Information Exchange
    - Comparability
    - Dispute Resolution
    - Regional Participation
    - Economic Planning Studies
    - Cost Allocation

Order 1000

- Order 1000
  - Planning Requirements
    - Produce a regional transmission plan, consistent with the principles of Order 890
    - Develop procedures to identify those transmission needs driven by public policy requirements for which potential transmission solutions will be evaluated
    - Determine merchant developer information/data necessary to assess impacts of proposed facilities

Order 1000

- Order 1000
  - Cost Allocation Requirements
    - Develop a method for allocating costs of those facilities that have been selected in the regional plan for purposes of cost allocation
      - Regional Cost Allocation Methodology
      - Interregional Cost Allocation Methodology
    - Regional and interregional cost allocation methodologies must satisfy the six cost allocation principles

Order 1000

- Order 1000
  - Six Cost Allocation Principles
    1) The cost of transmission facilities allocated in a way that is roughly commensurate with benefits.
    2) No involuntary allocation of costs to those who receive no benefits.
    3) Benefit to Cost threshold, if used to determine if facilities have sufficient net benefits to be selected for regional cost allocation, cannot exceed 1.25.
    4) The cost allocation method cannot allocate costs to entity's outside the region, unless that entity voluntarily agrees to assume cost.
    5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries must be transparent.
    6) A region may have different cost allocation methods for different types of facilities. Each cost allocation method must be clearly set out and explained.

FERC Order 1000

SERTP October 17th Proposal

Order 1000

- Regional Requirements – Order 1000
  - Develop procedures to identify those transmission needs driven by public policy requirements, for which potential transmission solutions will be evaluated

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Consideration of Transmission Needs Driven by Public Policy Requirements (PPRs)
  - SERTP Sponsors address transmission needs driven by PPRs in the routine planning, design, construction, operation, and maintenance of the transmission system.
    - Sponsors consider input of SERTP Stakeholders regarding transmission needs driven by PPRs
      - To be considered in the upcoming transmission planning cycle, input should be provided no later than 60 days after the SERTP Annual Transmission Planning Summit.
      - PPR must be a federal or state law/regulation
      - Sponsors will provide and post a response to Stakeholder input

Order 1000

- Consideration of Transmission Needs Driven by Public Policy Requirements (PPRs)
  - The Sponsors will evaluate SERTP Stakeholder input to determine if there is a transmission need driven by the PPR identified by the Stakeholder
  - If a transmission need is identified, that is not already addressed in the expansion planning process, the SERTP Sponsors will identify a transmission solution to address the need in the expansion planning processes.
  - Stakeholder input regarding potential transmission needs driven by PPRs may be directed to the governing OATT process as appropriate.
    - Ex: if the potential transmission need identified by the SERTP Stakeholder is essentially a request by a network customer to integrate a new network resource, the request would be directed to that existing OATT process.

Order 1000

- Regional Requirements – Order 1000
  - Determine which information/data is necessary for merchant developers to provide transmission providers in order to allow transmission providers to assess the reliability and operational impacts of proposed facilities

Order 1000

- Merchant Developer Data/Information
  - Merchant transmission developers who propose to develop a transmission facility potentially impacting the SERTP will provide information and data necessary for the Sponsors to assess potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on the region, including:
    - Transmission project timing, scope, network terminations, steady-state and stability modeling data, HVDC data (as applicable), details of service commitments, and other data necessary to assess potential impacts.

Order 1000

- Regional Requirements – Order 1000 A
  - A clear enrollment process will be established that defines how public utility and non-public utility transmission providers, make the choice to become part of, or to terminate participation in the SERTP region.

Order 1000

- Enrollment
  - Purpose
    - Entities that enroll in the SERTP may be allocated costs based upon the benefits received from a regional project included in the regional plan for Cost Allocation Purposes ("CAP")

Order 1000

- Enrollment
  - General Eligibility for Enrollment
    - A public utility or non-public utility, transmission service provider, and/or transmission owner having a statutory or tariff obligation to ensure that adequate transmission facilities exist to meet its firm service commitments within the SERTP region.

Order 1000

- Enrollment
  - Enrollment Requirement
    - A potential transmission developer and/or transmission dependent utility must enroll in the SERTP in order to be eligible to propose a regional project for CAP if it, an affiliate, or parent company has load in the region.

Order 1000

- Enrollment
  - How to Enroll?
    - A form will be posted on the Regional Planning website.
  - How to withdraw from enrollment?
    - Provide written notification of such intent at least 60 days prior to the Annual Transmission Planning Summit.
    - Termination effective at the end of the then-current transmission planning cycle.
    - Enrollee remains subject to regional cost allocations made while enrolled.

Order 1000

- Regional Requirements – Order 1000
  - Develop a method for allocating costs of those facilities that have been selected in the regional plan for purposes of cost allocation

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Transmission Developer Qualification Criteria
  - Demonstrate the necessary *financial capability* and technical expertise to develop, construct, operate and maintain the proposed transmission facility.
    - S&P credit rating of BBB- or higher (or similar credit rating from another agency if not rated by S&P)
    - <u>AND</u> demonstrated capability to finance U.S. energy projects equal to or greater than the cost of the proposed regional transmission project

Order 1000

- Transmission Developer Qualification Criteria
  - Demonstrate the necessary financial capability and *technical expertise* to develop, construct, operate and maintain the proposed transmission facility.
    - Demonstrated capability to develop, construct, operate, and maintain U.S. electric transmission projects of similar or larger complexity, size, and scope as the proposed project.
      - Summary of transmission projects in-service, under construction, and/or projects not completed including locations, operating voltages, mileages, development schedules, approximate installed costs; and how these facilities are owned, operated and maintained. This may include projects and experience provided by a parent company or affiliates or other experience relevant to the development of the proposed project.
      - List of NERC and/or Regional Entity reliability standard violations

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Transmission Facility Qualification Criteria
  - Regional in nature
    - Operating voltage of 300 kV or above
    - Spans 100 miles or more
    - Located in two or more balancing authorities
    - Consideration will be given to projects that do not fully meet the foregoing on a project by project basis to ensure the proposal satisfies similar regional criteria/provides similar regional benefits
  - Green-field project
  - Materially different from those projects previously considered in the expansion planning process
  - Able to be constructed and tied into the network by the recommended in-service date

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Submittal – Regional Proposal for CAP
  - Demonstration of Qualification Criteria
    - Transmission Developer (“TD”)
    - Regional Transmission Facility
  - NERC and/or Other Industry Registrations
  - Project Description
  - Capital Cost Estimate
  - Technical Analysis performed by “TD”
  - Data/Files to Evaluate the Proposal
  - Planned Approach to Satisfy Regulatory Req’s
  - Submittal Fee
  - Deadline for Submittal

Order 1000

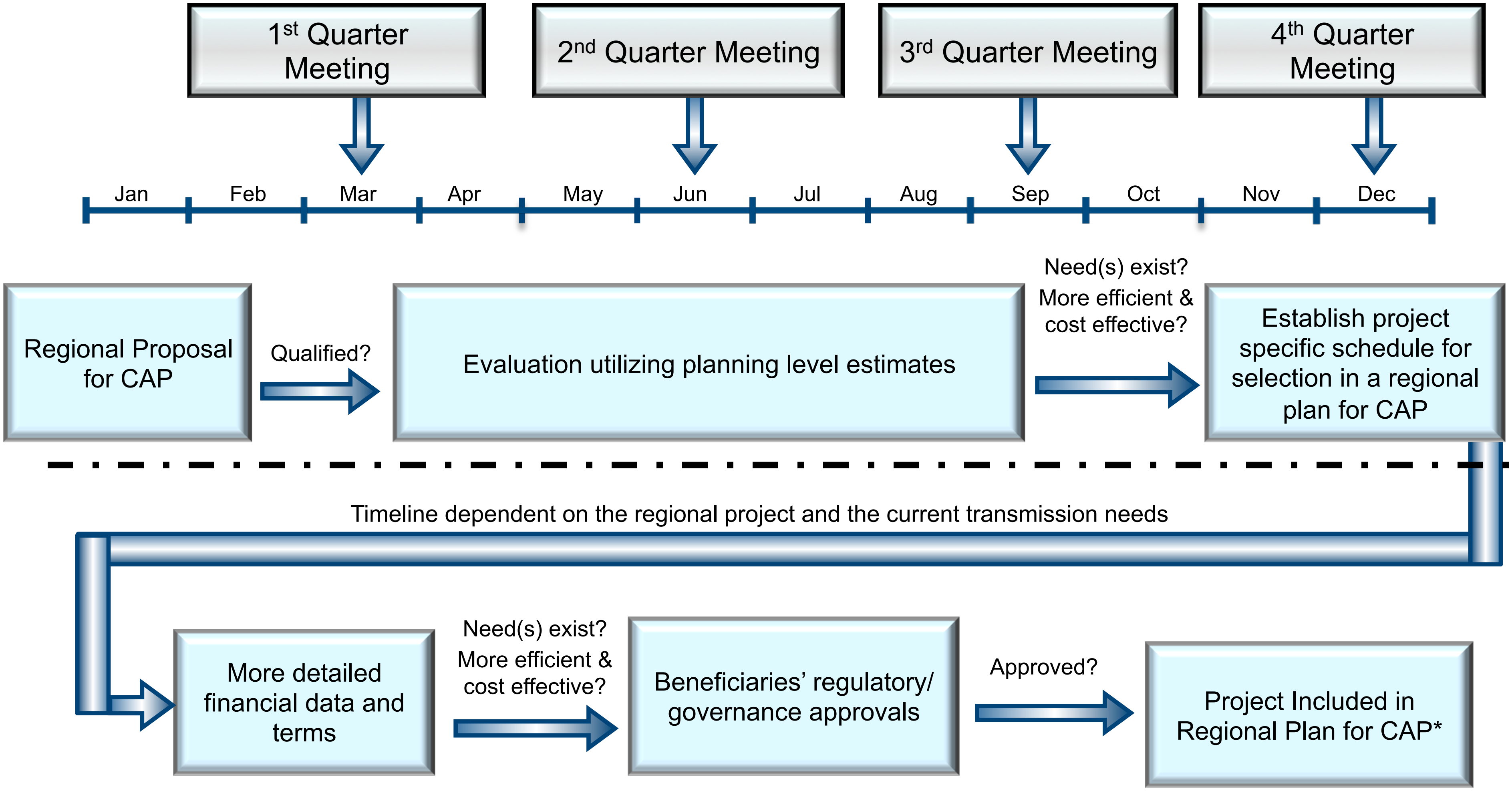
- Submittal – Regional Proposal for CAP
  - Submittal Fee
    - A non-refundable, administrative fee of $25,000 per regional proposal for CAP will be required
    - The fee will be used to offset the costs to review and process the qualification criteria and supporting documentation for each submittal

Order 1000

- Submittal – Regional Proposal for CAP
  - Deadline for Submittal
    - To be considered in the upcoming transmission planning cycle, a regional proposal for CAP should be provided no later than 60 days after the SERTP Annual Transmission Planning Summit.
      - The transmission developer will be notified within 30 days after the submittal deadline if there is an incomplete submittal or if qualification criteria is not met.
      - Within 15 days of such notification, the transmission developer can resubmit the necessary supporting documentation to remedy identified deficiencies.

Southeastern Regional TRANSMISSION PLANNING

Order 1000



*Project may be removed from regional plan for CAP based upon subsequent reevaluation, project delays/abandonment, or failure to meet developmental milestones

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Evaluation of Proposals for Selection in a Regional Plan for CAP
  - Regional Benefit to Cost Ratio of at least 1.25:
    - Benefit: Transmission costs avoided by the displaced projects
    - Cost: Transmission cost of the regional project proposed for selection in a regional transmission plan for CAP plus any additional projects required to implement the proposal
  - Initial evaluation based upon planning level cost estimates. Subsequent evaluation(s) performed based upon detailed financial terms provided by the transmission developer.
  - To be selected for CAP, the proposal must be approved by the jurisdictional/governance authorities of the beneficiaries.

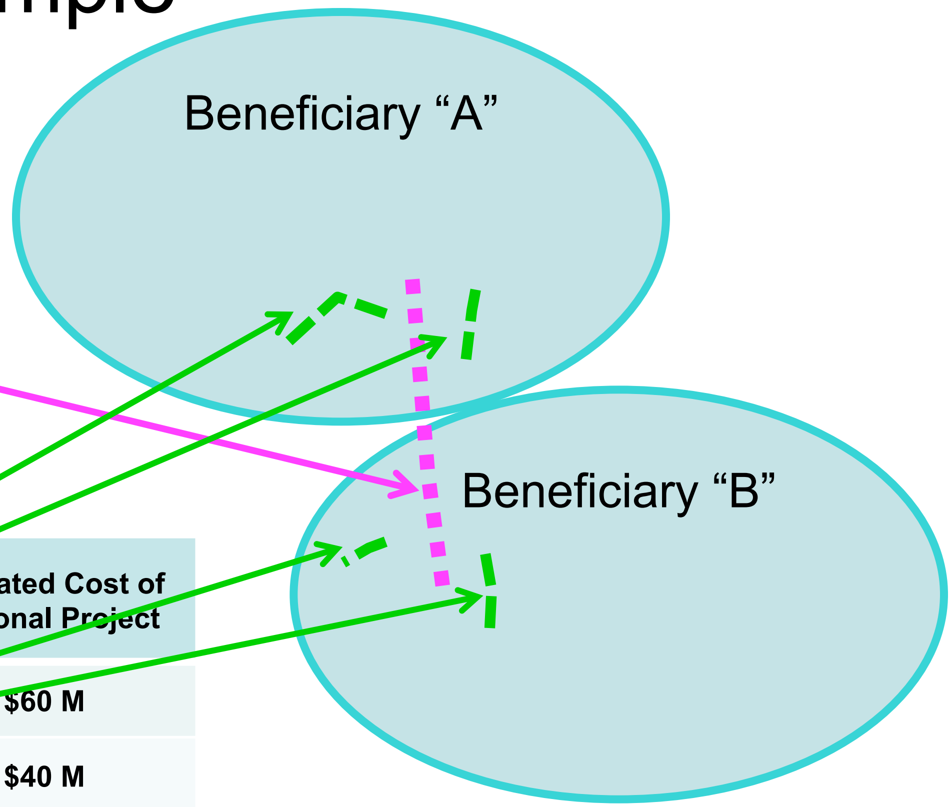
Order 1000

- Selection in a Regional Plan for CAP
  - If a regional transmission project is selected in a regional plan for CAP, the beneficiaries will be allocated costs of the regional transmission facility in proportion to their displaced transmission costs.

Order 1000

- Cost Allocation Example

Regional Project Cost	ΣDisplaced Project Cost	Regional Benefit to Cost Ratio
$100 M	$150 M	1.50



Beneficiary	Displaced Transmission Cost	Regional Cost Allocation %	Allocated Cost of Regional Project
“A”	$90 M	60%	$60 M
“B”	$60 M	40%	$40 M
Total	$150 M	100%	$100 M

Proposed Regional Facility
Displaced Transmission Facility

Southeastern Regional TRANSMISSION PLANNING

Order 1000

- Maintaining “Selected for CAP” Status
  - In order to remain included in a regional plan for CAP:
    - The regional proposal will continue to be evaluated in subsequent expansion planning process that reflect ongoing changes in actual and forecast conditions to ensure:
      - The regional proposal is still needed
      - The regional proposal remains more efficient & cost effective
    - The transmission developer must meet all established milestones necessary to develop and construct the transmission project, including:
      - Obtaining all necessary ROWs and environmental, state, and other governmental approvals
      - Executing a contract to address the terms and conditions associated with the development of the regional transmission project

Order 1000

- Contract Terms & Conditions
  - A contractual agreement(s) will address terms and conditions associated with the development of the regional transmission project in a regional plan for CAP, such as:
    - Specific financial terms associated with the development of the regional transmission project,
    - The allocation of the costs of the aforementioned facility,
    - Creditworthiness/project security requirements,
    - Operational control of the regional transmission facility,
    - Milestone reporting, including schedule of projected expenditures,
    - Engineering, procurement, construction, maintenance, and operation of the regional transmission facility,
    - Emergency restoration and repair responsibilities,
    - Reevaluation of the regional transmission facility, and
    - Non-performance or abandonment

Order 1000

- Delay / Abandonment
  - SERTP Sponsors will determine if alternative transmission projects may be required in addition to, or in place of, the proposal due to a delay or abandonment in the development of the regional transmission project selected for CAP. Circumstances prompting this evaluation include:
    - If notification is provided by the transmission developer that the proposed facility will be delayed
    - If the Sponsors are otherwise informed or become aware that the transmission developer is not meeting established project milestones.

Questions ?

NCTPC 2013 Study Activities and Study Scope

Mark Byrd

Progress Energy Carolinas

Purpose of Study

- **Assess Duke and Progress transmission systems' reliability and develop a single Collaborative Transmission Plan**

Steps and Status of the Study Process

Completed

1. Assumptions Selected
2. Study Criteria Established
3. Study Methodologies Selected
4. Models and Cases Developed
5. Technical Analysis Performed
6. Problems Identified and Solutions Developed
7. Collaborative Plan Projects Selected
8. Study Report Prepared

Study Assumptions Selected

- Study Years for reliability analyses:
  - Near-term: 2018 Summer, 2018/2019 Winter
  - Longer-term: 2023 Summer
- LSEs provided:
  - Input for load forecasts and resource supply assumptions
  - Dispatch order for their resources
- Interchange coordinated between Participants and neighboring systems

Study Criteria Established

- NERC Reliability Standards
  - Current standards for base study screening
  - Current SERC Requirements
- Individual company criteria

Study Methodologies Selected

- Thermal Power Flow Analysis
- Each system (Duke and Progress) will be tested for impact of other system's contingencies

Base Case Models Developed

- Started with 2012 series MMWG cases
- Detailed models for Duke and Progress systems
- Adjustments were made based on additional coordination with neighboring transmission systems
- Planned transmission additions from updated 2012 Plan were included in models

Resource Supply Options Selected

- **Last year**
  - Hypothetical new base load generation
  - NCTPC-PJM inter-regional wind study
- **This year**
  - Hypothetical import/export scenarios
  - Coordination with PJM for modeling transfers

2023 Hypothetical Import / Export

Resource From	Sink	Test Level (MW)
NORTH – PJM	Duke	1,000
SOUTH – SOCO	Duke	1,000
SOUTH – SCEG	Duke	1,000
SOUTH – SCPSA	Duke	1,000
EAST – Progress (CPLE)	Duke	1,000
WEST – TVA	Duke	1,000

2023 Hypothetical Import / Export

Resource From	Sink	Test Level (MW)
NORTH – PJM	Progress (CPLE)	1,000
SOUTH – SCEG	Progress (CPLE)	1,000
SOUTH – SCPSA	Progress (CPLE)	1,000
WEST – Duke	Progress (CPLE)	1,000
WEST – Duke	SOCO	1,000

2023 Hypothetical Import / Export

Resource From	Sink	Test Level (MW)
NORTH – PJM	Duke / Progress (CPLE)	1,000 / 1,000
WEST – Duke / Progress (CPLE)	PJM	1,000 / 1,000
EAST – Progress (CPLE)	PJM	1,000
WEST – Duke	PJM	1,000
SOUTH – SOCO *	PJM	1,000

Enhanced Transmission Access Requests

- TAG memo was distributed on February 1, 2013 requesting input
- The deadline for input was February 12, 2013
- The NCTPC is considering a joint wind study with South Carolina

Proposed Carolinas Joint Wind Study

- ***Joint effort of NCTPC and SCRTP***
- ***Assess impacts of various wind injection sites along the NC and SC coasts***
- ***Sites to be tested will be selected based on latest available off-shore wind data and studies***

Technical Analysis

- Conduct thermal screenings of the 2018 and 2023 base cases
- Conduct thermal screenings of the 2023 hypothetical transfer scenarios and coordinate with PJM

Problems Identified and Solutions Developed

- Identify limitations and develop potential alternative solutions for further testing and evaluation
- Estimate project costs and schedule

Collaborative Plan Projects Selected

- Compare all alternatives and select preferred solutions

Study Report Prepared

- Prepare draft report and distribute to TAG for review and comment

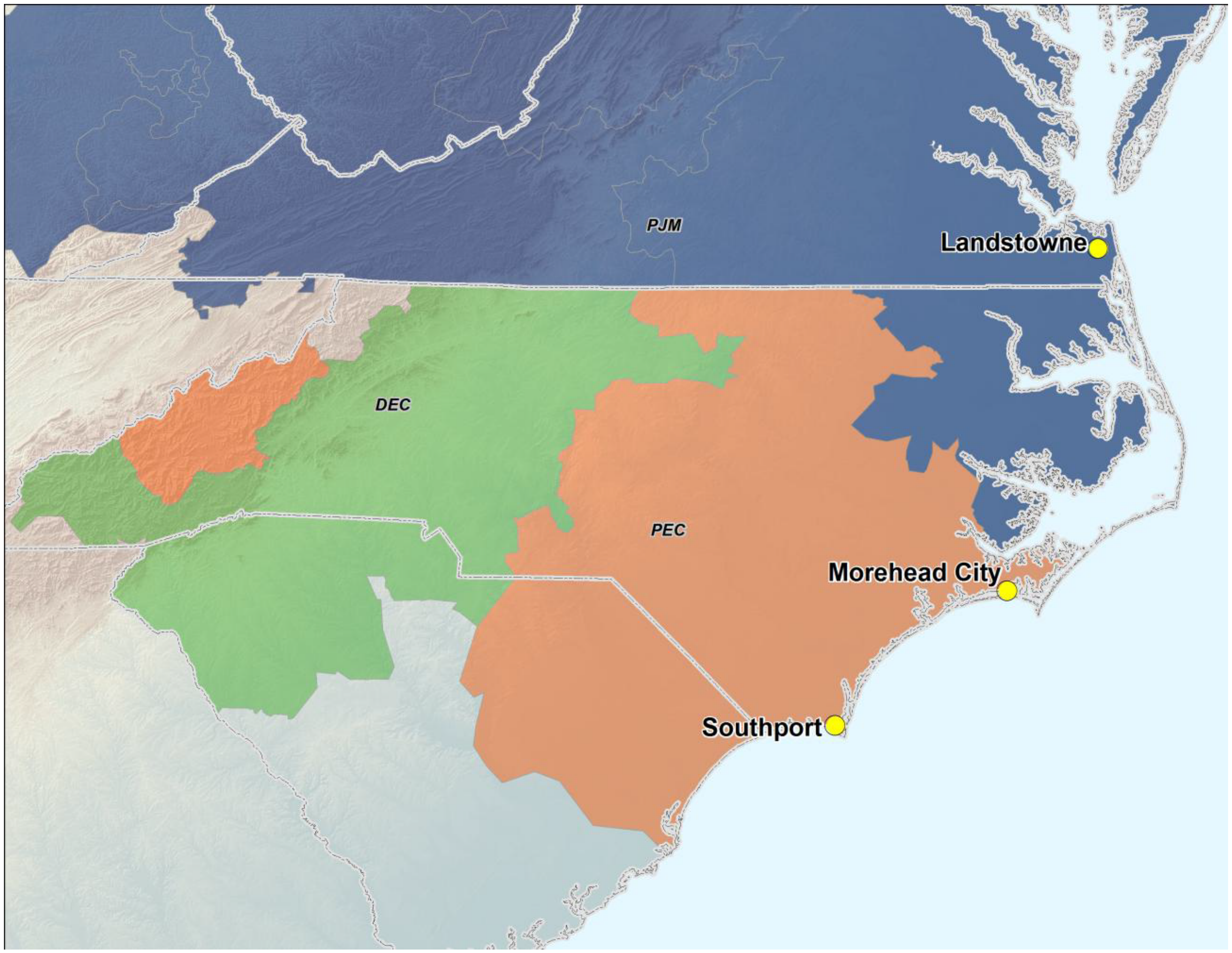
Questions ?

NCTPC – PJM Joint Interregional Reliability Study Report

Orvane Piper
Duke Energy

Scope of 2012 Joint Wind Study

- Year 2027 summer cases used for the Wind Generation Scenarios located off the North Carolina / Virginia coast
- Three off-shore injection points studied
  - Dominion’s Landstown 230 kV Substation
  - PEC’s Morehead City area
  - PEC’s Southport area
- The load level of each study area was set to 60% of 2027 summer forecasted peak levels

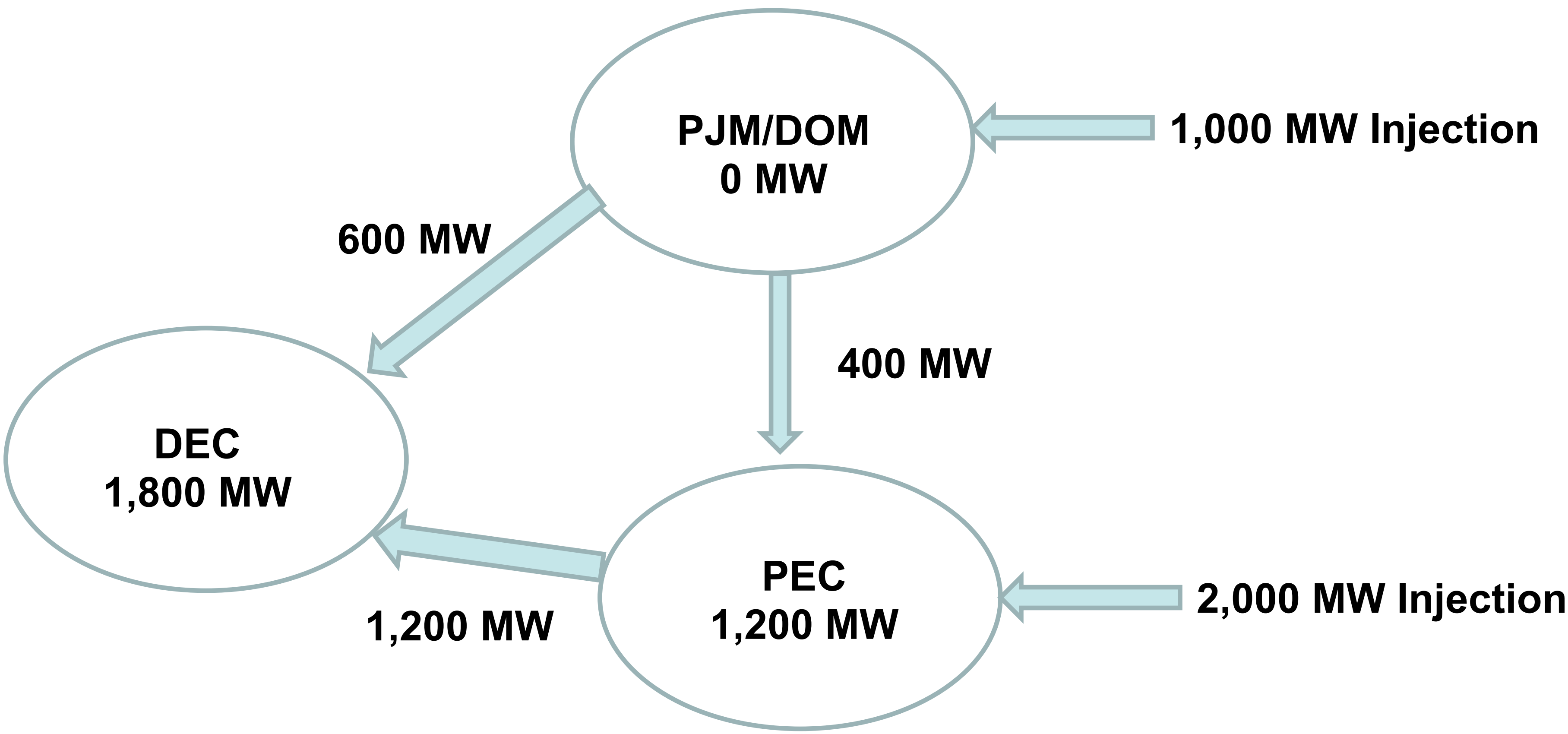

PJM
Landstowne
DEC
PEC
Morehead City
Southport

Wind Study Methodology

- The 2027 off-peak case was screened for base thermal overloads and voltage violations
- The PEC system included transmission upgrades from prior NCTPC wind studies already incorporated
- A thermal N-1 analysis was conducted to test the post-contingency reliability of the network
- Solutions were determined, modeled in the scenario case, and then verified to ensure the solutions were effective

2027 Summer
60% of Peak Case

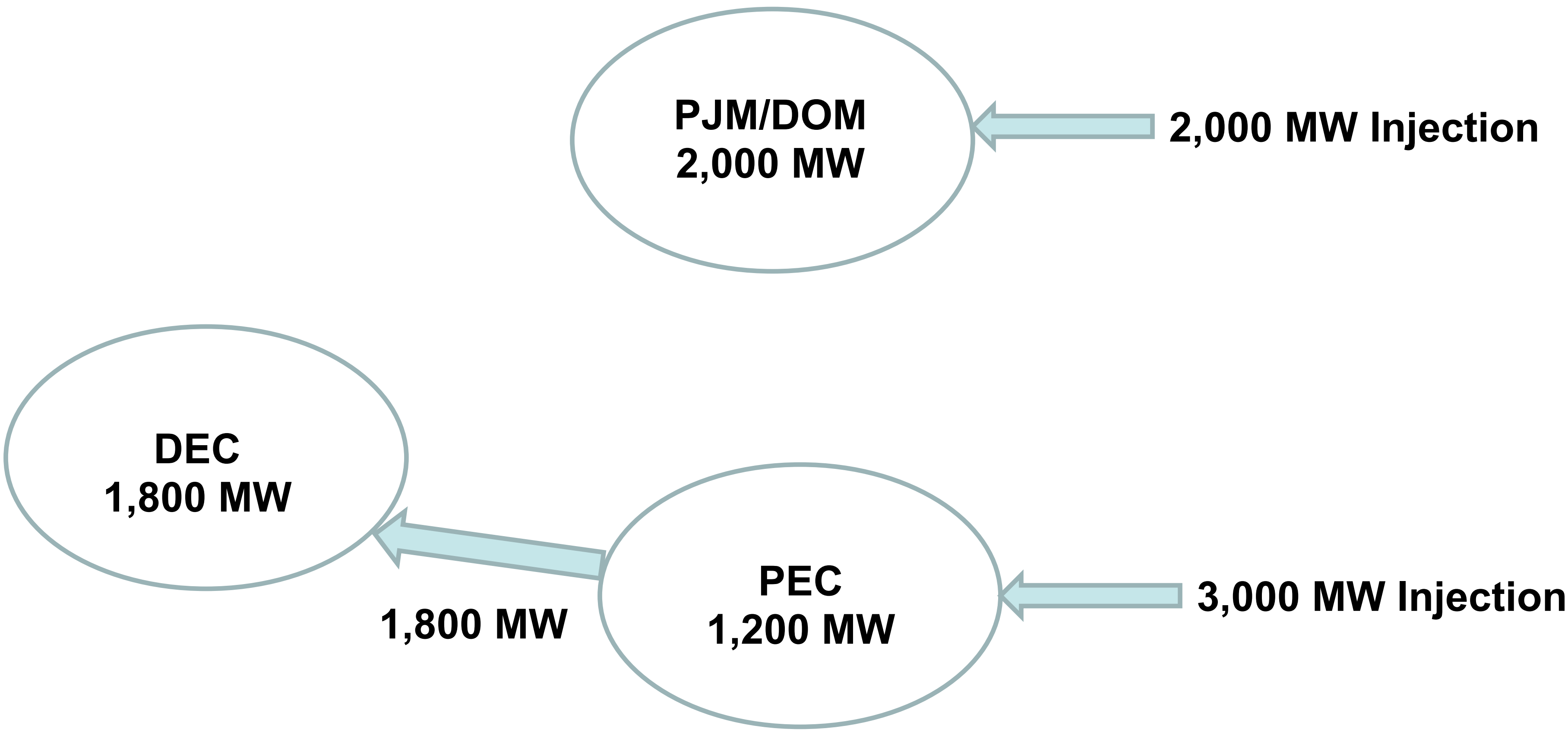
Scenario #1



Scenario #1 PEC Upgrades Line/Equipment Name	Estimated Cost (M)
Morehead 500 kV Switching Station	$30
Jacksonville 500 kV Substation	$60
Jacksonville - Morehead Switching Station 500 kV Lines	$200
Wommack 500 kV Substation	$60
Jacksonville - Wommack 500 kV Line	$120
Southport 500 kV Switching Station	$30
Sutton North 500 kV Substation (including 230 kV work)	$70
Southport - Sutton North 500 kV Lines	$150
Cumberland - Sutton North 500 kV Line	$210
Cumberland 500 kV Substation - Add terminals	$2
TOTAL	**$932 M**

2027 Summer
60% of Peak Case

Scenario #2



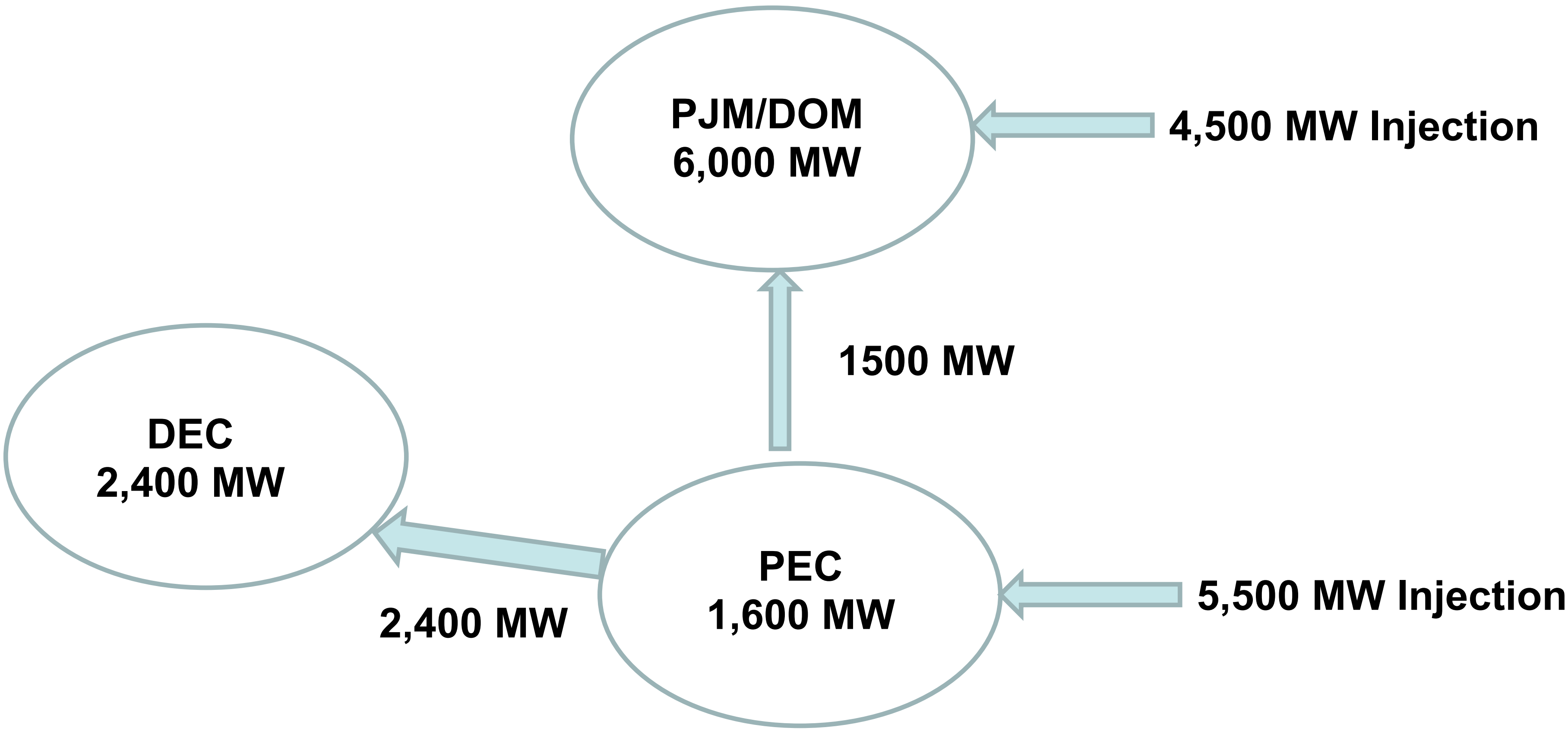
Scenario #2 DEC Upgrades Line/Equipment Name	Estimated Cost (M)
McGuire – Riverbend 230 kV Line Reactors	$4
TOTAL	**$4 M**

Scenario #2 PEC Upgrades Line/Equipment Name	Estimated Cost (M)
Morehead 500 kV Switching Station	$30
Jacksonville 500 kV Substation	$30
Jacksonville - Morehead Switching Station 500 kV Lines	$200
Wommack 500 kV Substation	$30
Jacksonville - Wommack 500 kV Line	$120
Cumberland - Jacksonville 500 kV Line	$210
Jacksonville - Sutton North 230 kV Line	$90
Southport 500 kV Switching Station	$30
Sutton North 500 kV Substation (including 230 kV work)	$70
Southport - Sutton North 500 kV Lines	$150
Cumberland - Sutton North 500 kV Line	$210
Cumberland 500 kV Substation - Add terminals	$4
SVC at Sutton North	$40
TOTAL	**$1,214 M**

Scenario #2 PJM Upgrades Line/Equipment Name	Estimated Cost (M)
2nd Landstown – Stumpy Lake 230 kV Line	$4
TOTAL	**$4 M**

2027 Summer
60% of Peak Case

Scenario #3



Scenario #3 DEC Upgrades Line/Equipment Name	Estimated Cost (M)
McGuire – Riverbend 230 kV Line Reactors	$4
TOTAL	**$4 M**

Scenario #3 PEC Upgrades Line/Equipment Name	Estimated Cost (M)
Morehead 500 kV Switching Station	$30
Jacksonville 500 kV Substation	$60
Jacksonville - Morehead Switching Station 500 kV Lines	$300
Wommack 500 kV Substation	$60
Jacksonville - Wommack 500 kV Lines	$200
Cumberland - Jacksonville 500 kV Line	$210
Jacksonville - Sutton North 500 kV Line	$135
Wake - Wommack 500 kV Line	$195
Wake 500 kV Sub - Add terminals	$2
Southport 500 kV Switching Station	$30
Sutton North 500 kV Substation (including 230 kV work)	$70
Southport - Sutton North 500 kV Lines	$150
Cumberland - Sutton North 500 kV Line	$210
Cumberland 500 kV Substation- Add terminals	$4
SVC at Sutton North	$40
SVC at Wommack	$40
TOTAL	**$1,736 M**

Scenario #3 PJM Upgrades Line/Equipment Name	Estimated Cost (M)
Landstown 500 kV Substation	$18.5
Landstown 500/230 kV Transformers	$32
Chickahominy 500/230 kV Transformer	$16
Surry – Chickahominy 500 kV Line	$171
Landstown – Fentress 500 kV Line	$57
Landstown – Yadkin 500 kV Line	$38
2nd Landstown – Stumpy Lake 230 kV Line	$4
2nd Stumpy Lake – Thrasher 230 kV Line	$4
2nd Fentress – Thrasher 230 kV Line	$8
TOTAL	**$349 M**

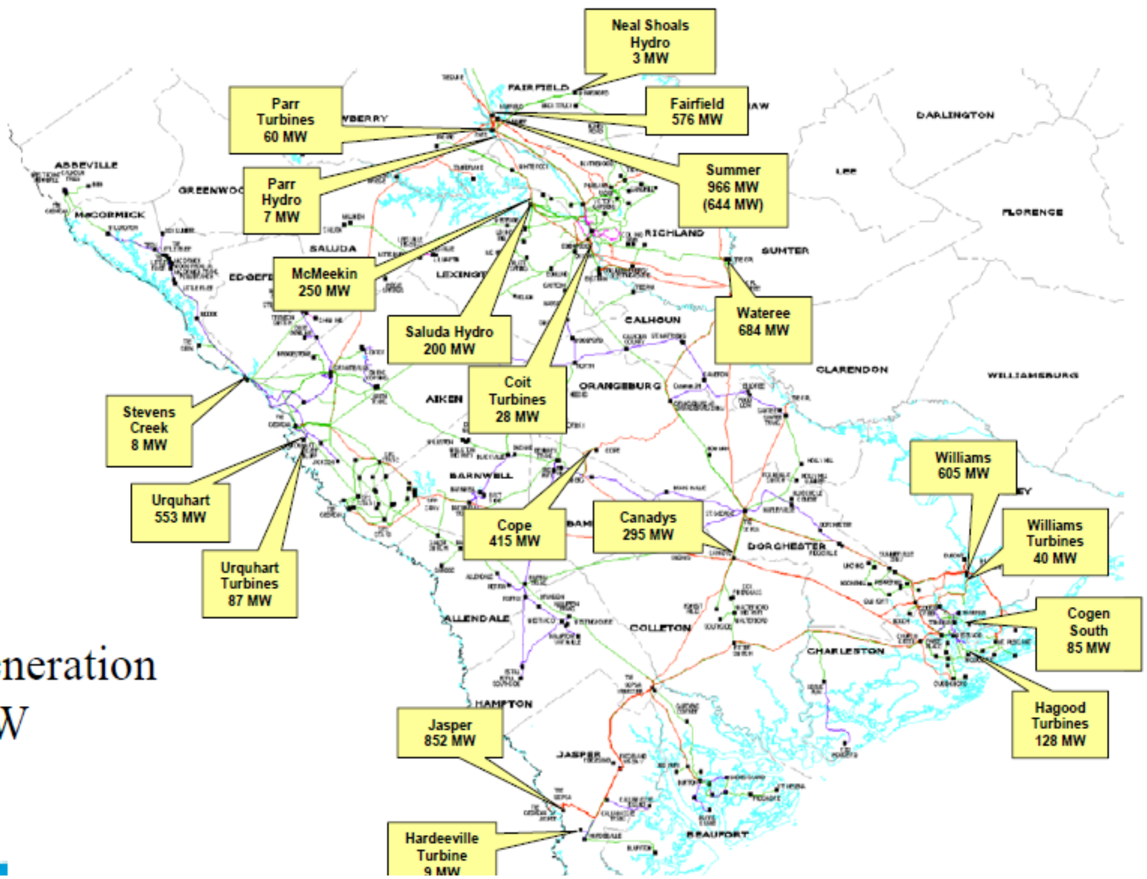
Questions ?

Regional Studies Reports

Bob Pierce
Duke Energy

South Carolina Regional Transmission Planning (SCRTP)

Existing Generation



Rated Generation
5,529 MW

Generation Plan

Reductions

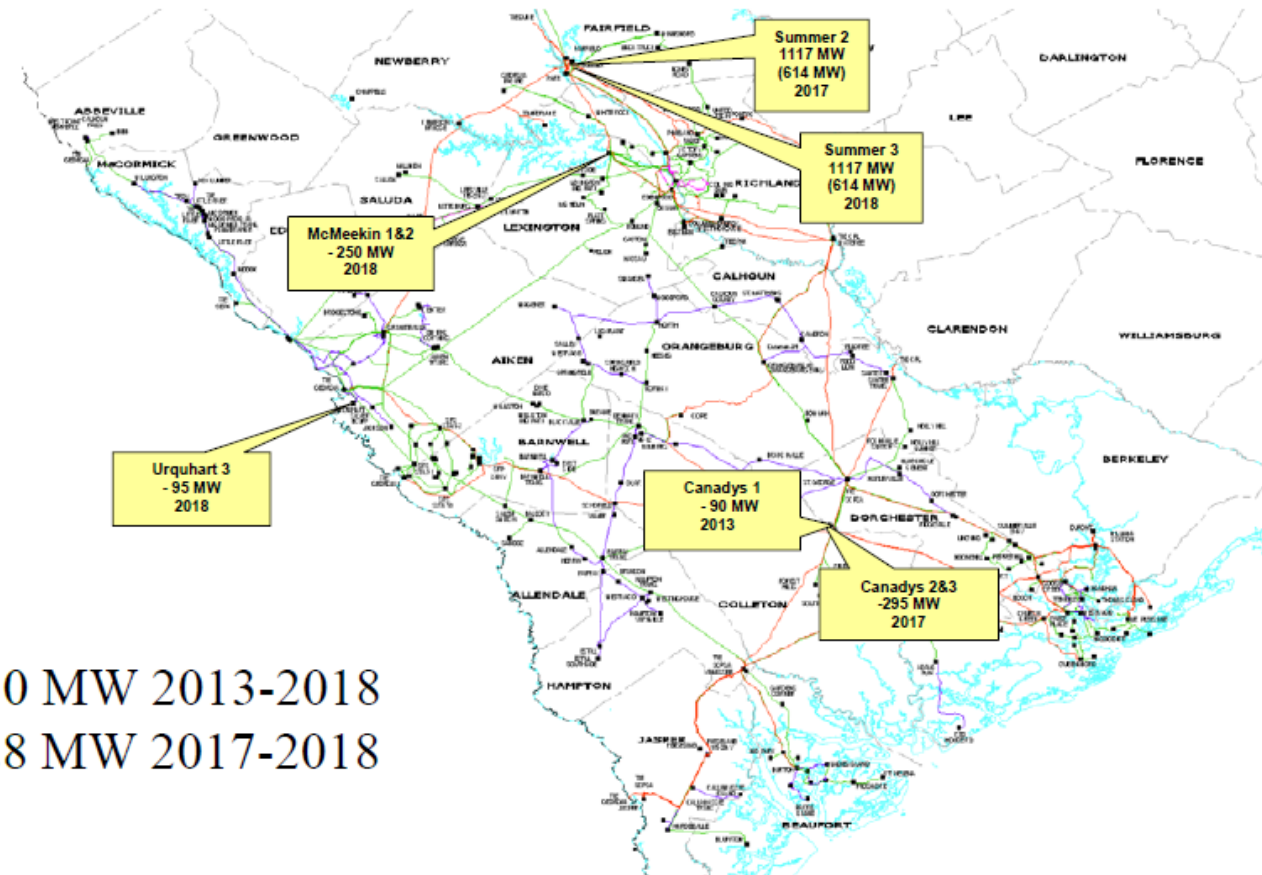
- 90 MW Coal 2013
- 245 MW Coal 2017
- 345 MW Coal 2018

Generation Plan

Additions

- 1117 MW of SCE&G/Santee Cooper Base Load Nuclear Generation planned for 2017 (V. C. Summer)
- 1117 MW of SCE&G/Santee Cooper Base Load Nuclear Generation planned for 2018 (V. C. Summer)

Generation Changes



- 730 MW 2013-2018
+ 1228 MW 2017-2018

Generation Resources

Existing Connected Generation

Cross 1- 4
Grainger 1, 2
Hilton Head Turbines 1- 3
Jefferies 1, 2, 3, 4, 6 (Hydro)
Jefferies 1, 2, 3, 4 (Steam)
Myrtle Beach Turbines 1-5
Winyah 1-4

J.S. Rainey Power Block 1
J.S. Rainey 2A, 2B
J.S. Rainey 3-5
Spillway (Hydro)
St. Stephen 1-3 (Hydro)
V.C. Summer #1

2013 Economic Planning Scenarios

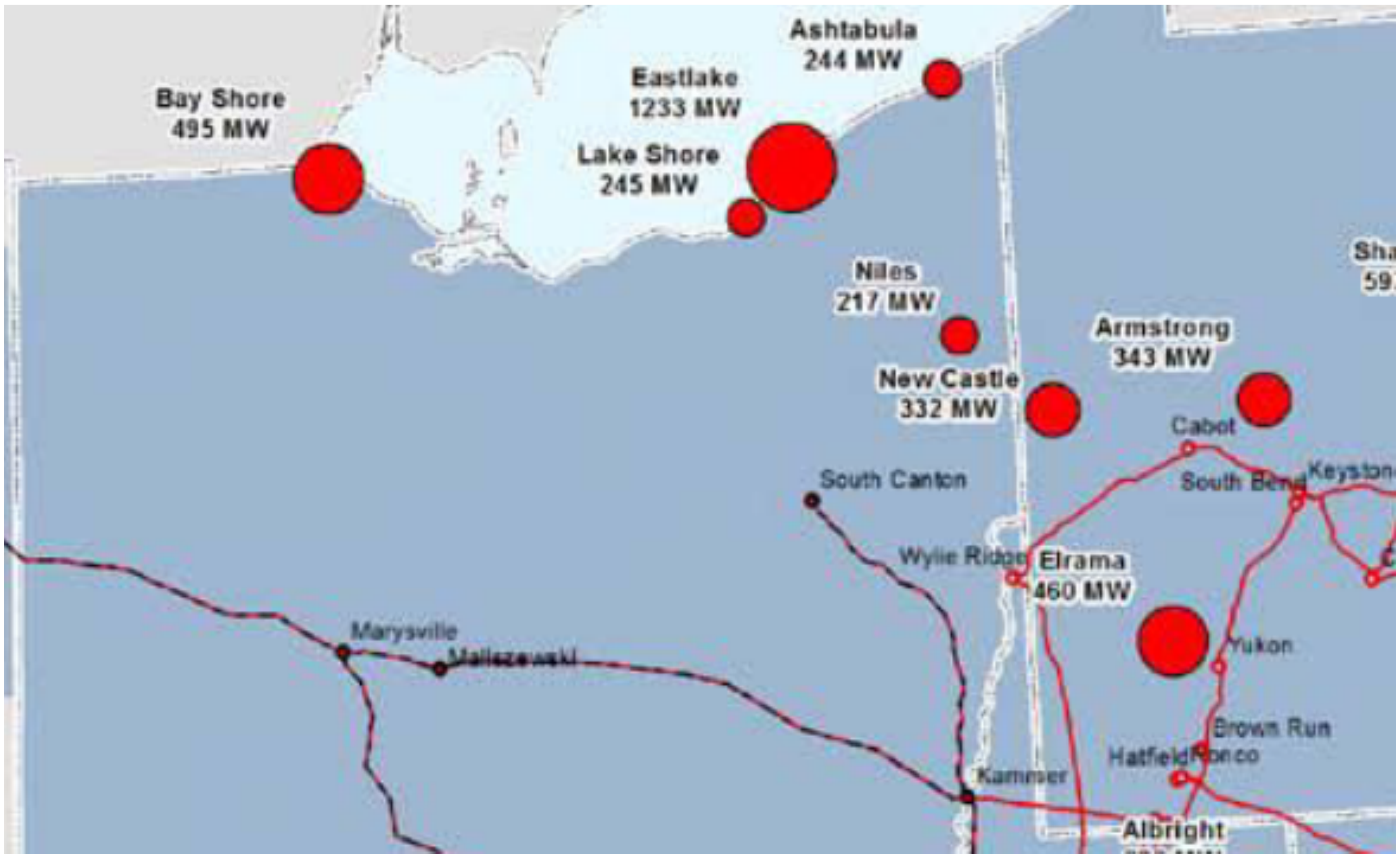
Source	Sink	Amount (MW)	Year	Study Conditions
Southern	SCPSA	500	2014	Summer Peak
Southern	SCPSA	500	2014	Winter Peak

www.scrtp.com

PJM Baseline Reliability Assessment

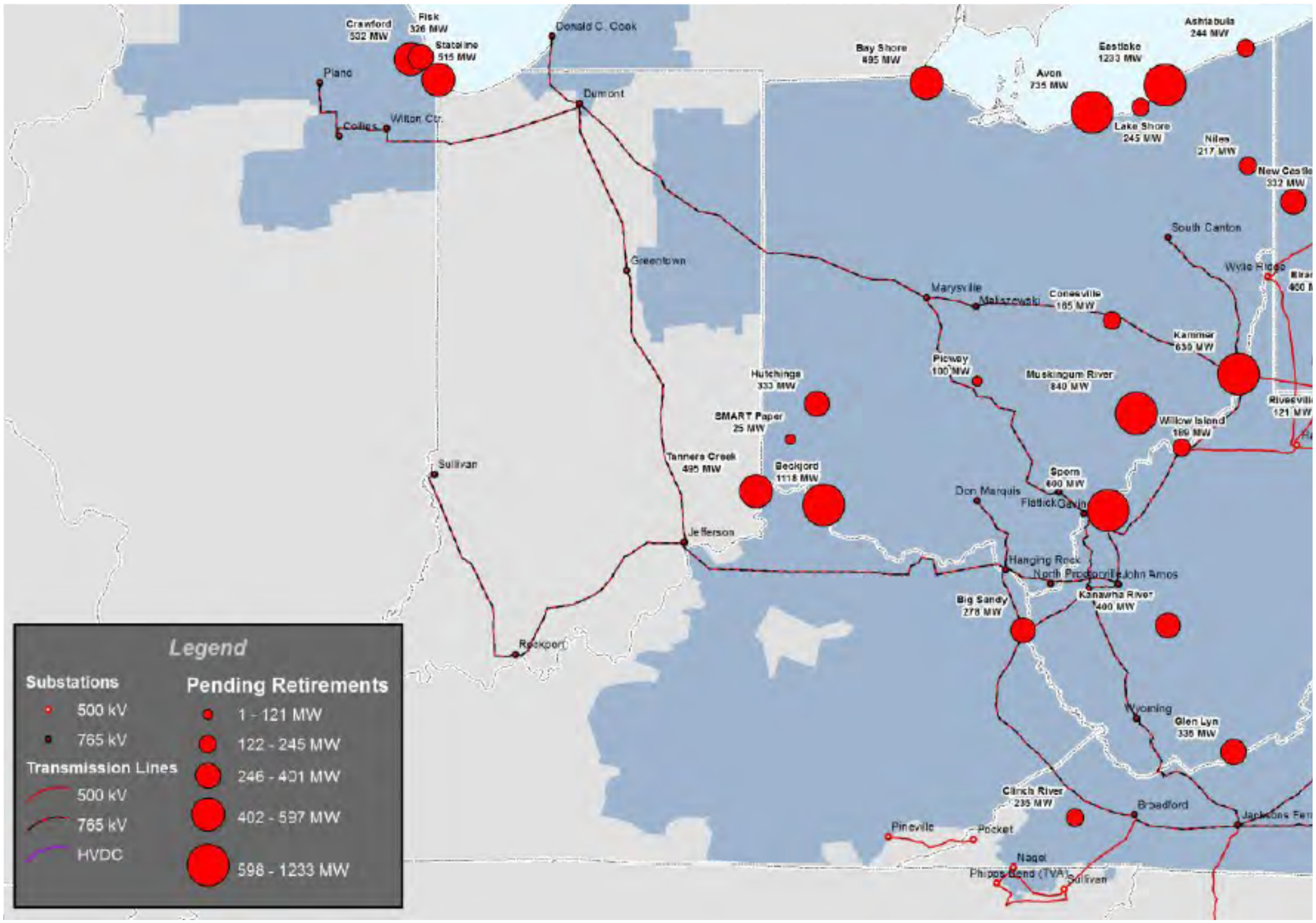
- **For the 2012 RTEP cycle, over 11,000 MW of existing generation has announced its intentions to deactivate in the near future.**

- **In order to establish a model which accurately included all expected generation retirements, PJM performed many sets of analysis to study the effects of these generation retirements on the system**


Ashtabula
244 MW
Eastlake
1233 MW
Bay Shore
495 MW
Lake Shore
245 MW
Niles
217 MW
Armstrong
343 MW
New Castle
332 MW
Cabot
South Canton
South Bend
Wylie Ridge
Elrama
460 MW
Marysville
Yukon
Brown Run
Hatfield
Kammer
Albright

American Transmission Systems, Incorporated

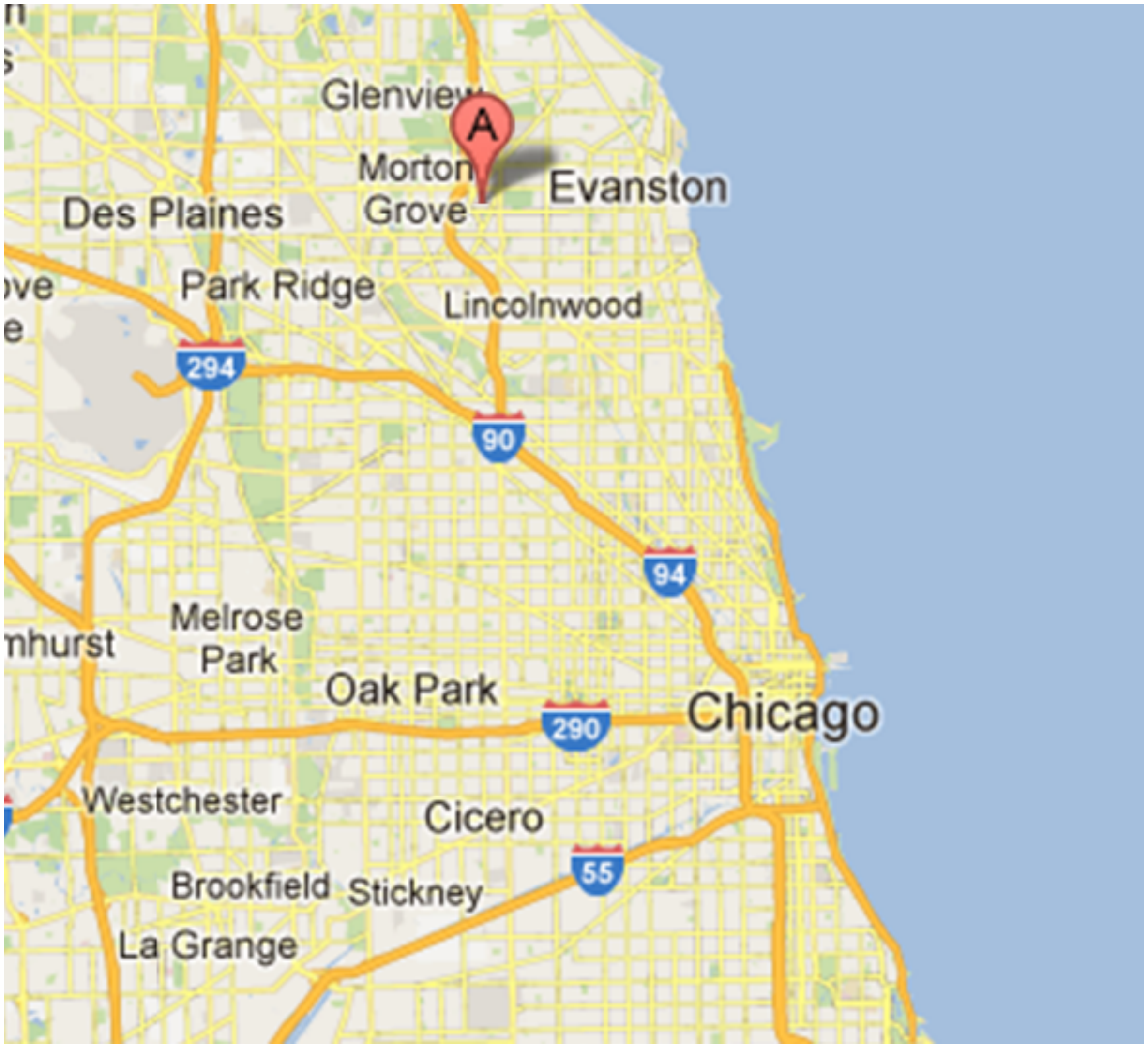
- Convert Eastlake unit 1 to synchronous condensers - 6/1/2015 - $20M
- Convert Eastlake unit 2 to synchronous condensers - 6/1/2015 - $20M
- Convert Eastlake unit 3 to synchronous condensers - 6/1/2015 - $20M
- Convert Eastlake unit 4 to synchronous condensers - 6/1/2014 - $20M
- Convert Eastlake unit 5 to synchronous condensers - 6/1/2013 - $20M
- Convert Lakeshore 18 to a synchronous condenser - 6/1/2015 - $20M

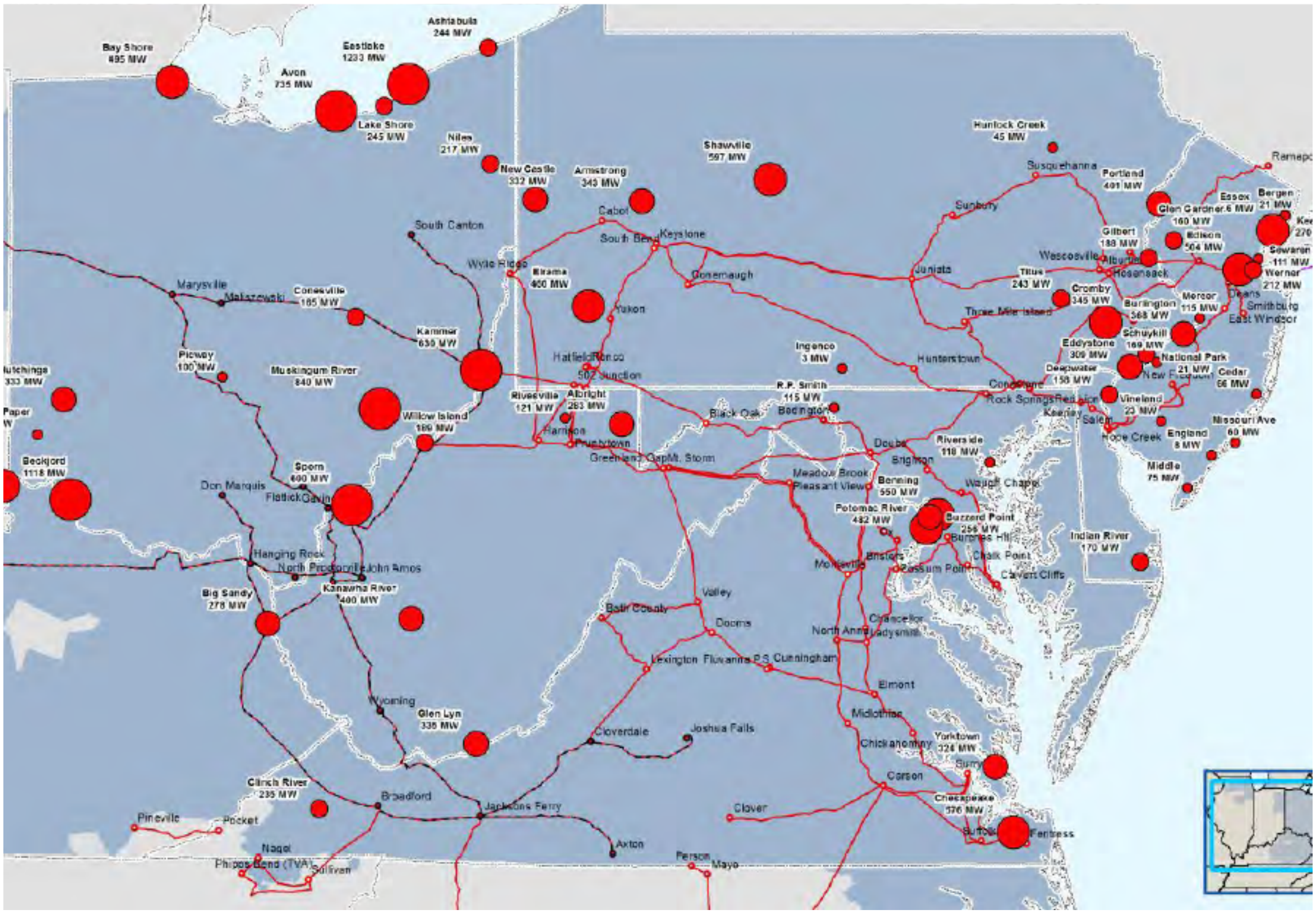

Legend
Substations
500 kV
765 kV
Transmission Lines
500 kV
765 kV
HVDC
Pending Retirements
1 - 121 MW
122 - 245 MW
246 - 401 MW
402 - 597 MW
598 - 1233 MW

Baseline Upgrade b2127

- Overview of Reliability Problem
  - Criteria Violation: Failure of ComEd dynamic voltage recovery criteria
  - Contingency:
  - Criteria test: ComEd criteria

- Overview of Reliability Solution
  - Description of Upgrade: Install two 300 MVAR SVC's on the 138 kV red and blue buses at Prospect Heights substation
  - Upgrade In-Service Date: June 01, 2014
  - Estimated Upgrade Cost: $75.00 M
  - Construction Responsibility: ComEd


Glenview
A
Morton Grove
Evanston
Des Plaines
Park Ridge
Lincolnwood
294
90
94
Melrose Park
Oak Park
290
Chicago
Westchester
Cicero
55
Brookfield
Stickney
La Grange



Baseline Upgrade b1912

- Overview of Reliability Problem
  - Criteria Violation: Voltage collapse in the VA Beach area
  - Contingency: Loss of Suffolk – Yadkin 500 kV and Yadkin – Fentress 500 kV
  - Criteria test: NERC TPL-003 Category C (N-1-1 Voltage)

- Overview of Reliability Solution
  - Description of Upgrade: Install a 500 MVAR SVC at Landstown 230 kV
  - Upgrade In-Service Date: June 01, 2016
  - Estimated Upgrade Cost: $60.00 M
  - Construction Responsibility: Dominion

Baseline Upgrade b2125

- Overview of Reliability Problem
  - Criteria Violation: High voltage on the 230 kV transmission system in Northern Virginia during periods of light system load
  - Contingency:
  - Criteria test: Operation Performance, Light Load

- Overview of Reliability Solution
  - Description of Upgrade: Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations
  - Upgrade In-Service Date: December 01, 2013
  - Estimated Upgrade Cost: $ 24.00 M
  - Construction Responsibility: Dominion

Baseline Upgrade b2126

- Overview of Reliability Problem
  - Criteria Violation: High voltage on the 230 kV transmission system in Eastern Virginia during periods of light system load
  - Contingency:
  - Criteria test: Operation Performance, Light Load

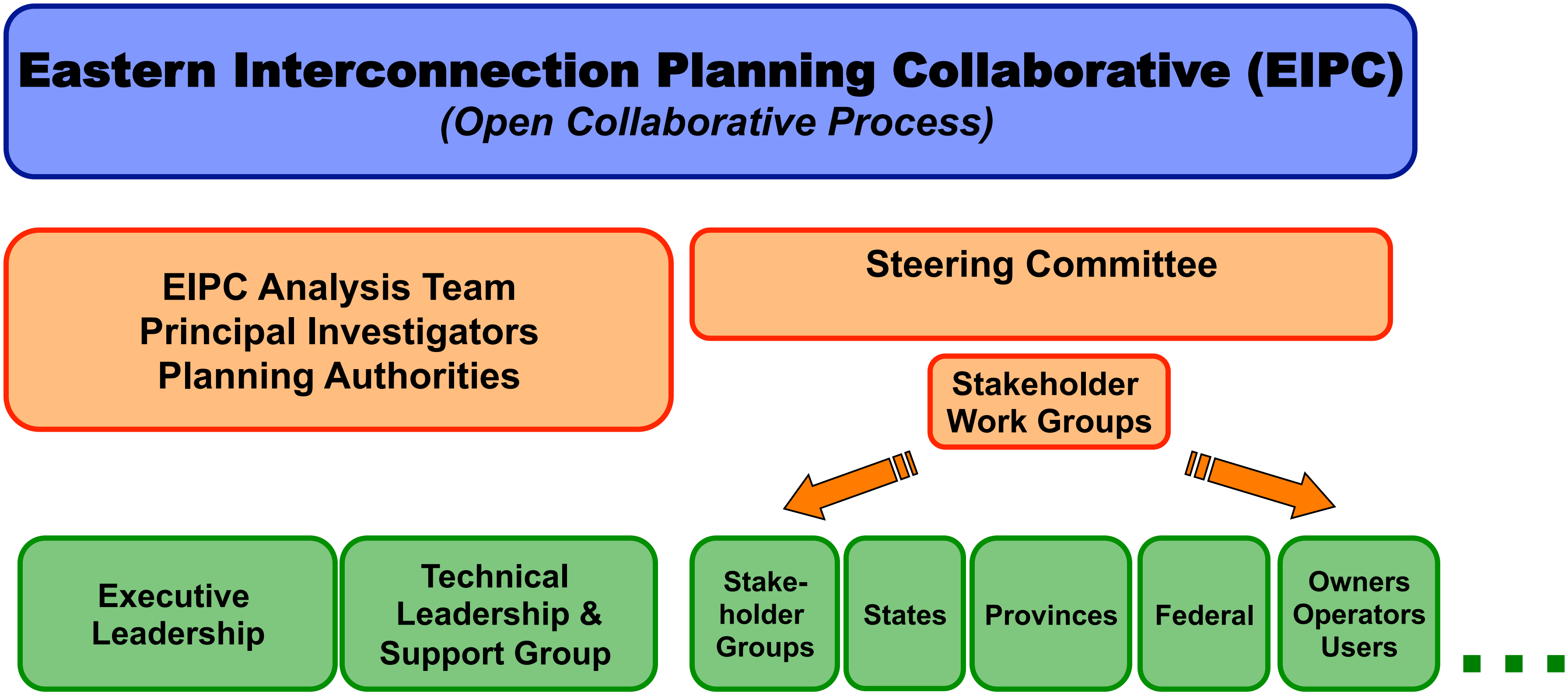
- Overview of Reliability Solution
  - Description of Upgrade: Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations
  - Upgrade In-Service Date: May 01, 2014
  - Estimated Upgrade Cost: $ 12.00 M
  - Construction Responsibility: Dominion

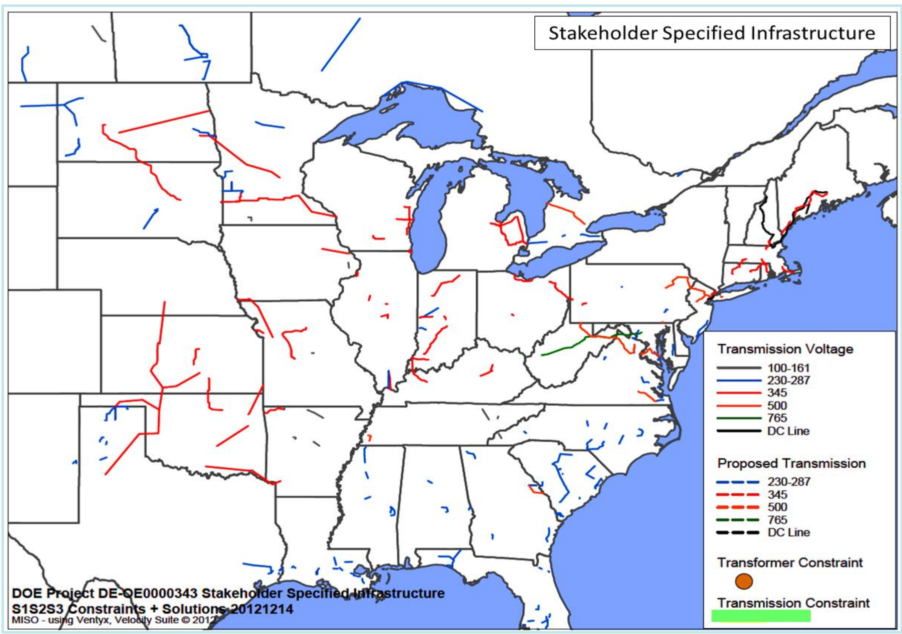
Eastern Interconnection Planning Collaborative (EIPC)

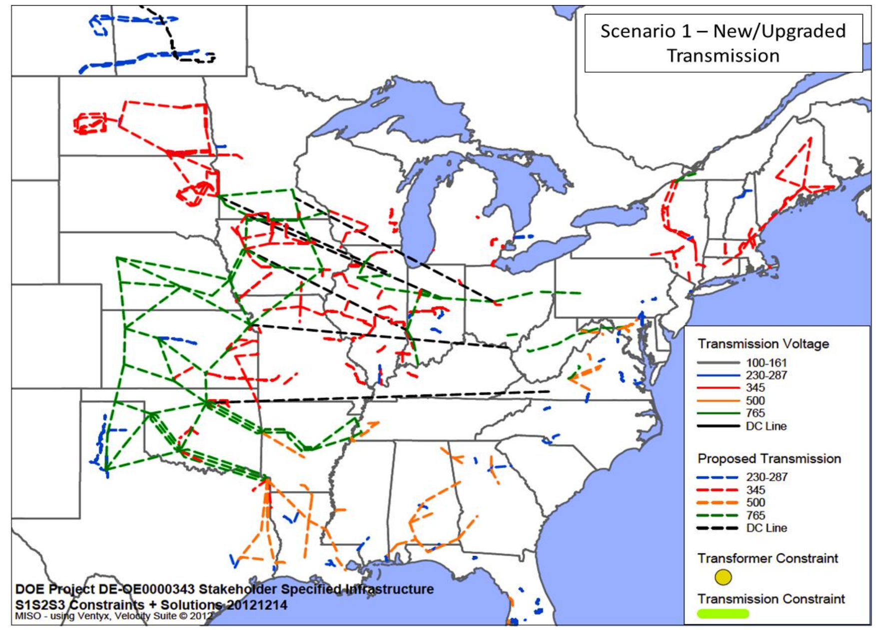
EIPC background

- EIPC Objectives
  1. Integration (“roll-up”) and analysis of approved regional plans
  2. Development of possible interregional expansion scenarios to be studied
  3. Development of interregional transmission expansion options

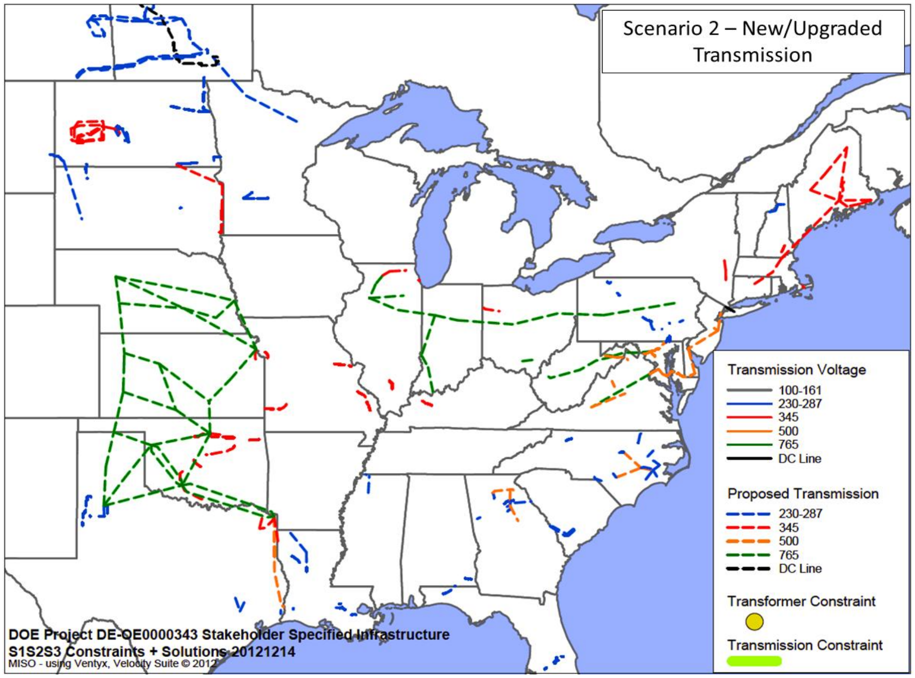
EIPC Structure

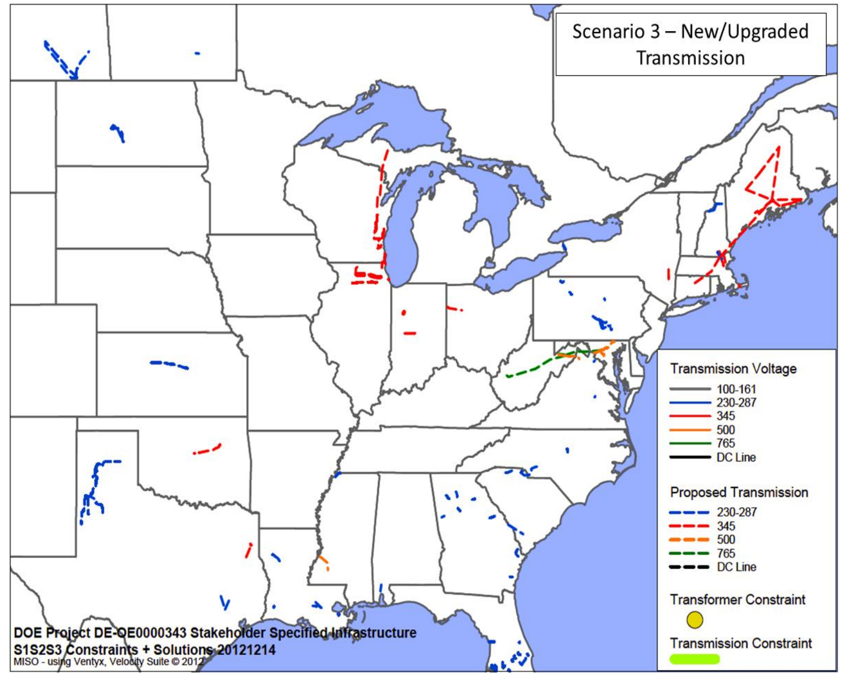






- Stakeholder Specified Infrastructure part of the base model
- Scenario 1 - Combined Policies (80% carbon reduction, significant EE/DR/DG), required largest transmission build out
  - This included significant HVDC needed to move power long distances





- Scenario 2, National RPS (30%) Implemented Regionally, required a fair amount of transmission
- Scenario 3, Business as Usual, required the least additional transmission

2030 O&M Costs - ($2010 Billions)			
Costs	Scenario 1: Combined Policy	Scenario 2: RPS Implemented Regionally	Scenario 3: Business as Usual
Production Costs - Fuel	$ 40.8	$ 73.8	$ 85.1
Production Costs - Variable O&M	$ 6.4	$ 15.5	$ 18.4
CO2 Costs	$ 45.3	$ 0.1	$ 0.2
Policy Driven Energy Efficiency	$ 8.9	$ 1.5	$ 1.5
CO2 Price Driven Energy Efficiency	$ 10.0	$ -	$ -
Demand Response O&M	$ 0.6	$ 0.3	$ 0.3
Variable Resource Integration	$ 2.9	$ 2.5	$ 1.0
Fixed O&M	$ 34.7	$ 52.1	$ 48.1
Total O&M Costs	**$ 149.6**	**$ 145.9**	**$ 154.5**
Total O&M Costs without CO2	**$ 104.3**	**$ 145.7**	**$ 154.4**

Overnight Capital Costs for Capital through 2030 ($2010 Billions)			
Costs	Scenario 1	Scenario 2	Scenario 3
Transmission - Generation Interconnection	$ 49.6	$ 54.3	$ 7.3
Transmission - Constraint Relief	$ 48.4	$ 13.0	$ 7.9
Transmission - Voltage Support	$ 0.5	$ 0.1	$ 0.2
Generation	$ 868.1	$ 679.4	$ 242.3
Nuclear Uprates	$ 4.9	$ 4.9	$ 4.9
Pollution Retrofit Costs	$ 6.8	$ 20.2	$ 22.0
Distributed Generation	$ -	$ -	$ -
Total Capital Costs	$ 978.2	$ 771.9	$ 284.6

- These costs are extremely high level, indicative only costs
  - Mix of annual 2030 costs and overnight capital costs
- Many costs have not been included in this analysis
- Costs reflect very different economies

	Scenario 1 Base - Combined Policies	Scenario 2 Base - National RPS Implemented Regionally	Scenario 3 Base - Business as Usual
Emissions (short tons)			
SO2 (000)	93	873	1,122
N0x (000)	21	1,300	1,771
CO2 (000)	358	1,391	1,792
Peak Demand (MW)	565,012	673,108	690,492
Energy (Twh)	2,979	3,621	3,687

EIPC 2013 Activities

- Phase 2 Gas-Electric Interface Analyses
- EIPC Work Plan 2013-2014 (non-grant)

EIPC Work Plan 2013-2014

Phase 2 Gas-Electric Interface

- Proposed scope – Analysis of the interface between natural gas and electric transmission infrastructures
- Principal Investigators from EIPC – PJM as the project recipient, New England ISO, the Independent Electricity System Operator (IESO) Ontario, Canada, New York ISO, Midwest ISO, and TVA
- Timeline – January, 2013 to December, 2014
- Technical analysis to be performed by a new contractor as a result of an RFP (spring, 2013)

EIPC Work Plan 2013-2014

- Create/modify 2018 and 2023 steady-state load-flow models
  - Summer Peak (other seasons as needed)
- Perform AC analysis for model validation
- Perform linear transfer analysis as specified in SMLFWG Procedure Manual
- Development of future transmission enhancements as required
- Compilation of analysis into a report

EIPC Work Plan 2013-2014

SMLFWG Case Development

- 2012 ERAG MMWG cases will be used as a starting point
- Planning Authorities will adjust loads, interchange, generation, etc. as necessary
- Regional Coordinators will assist with accurate data collection
- AC N-1 analysis will be performed for model validation

EIPC Work Plan 2013-2014

Linear Analysis

Will be performed to demonstrate strength of the grid, not to identify constraints such that transmission projects can be identified and transfer capability increased. Once linear analysis performed, individual Planning Authorities (PA) will share expansion plans with other PA on regional basis to look for enhancements.

Report

Once models are finalized, analyses are performed, enhancements are identified, and reporting data gathered, “Roll-Up” report will be assembled and sent out for review. Meeting will be held with stakeholders to review report (**11/13**)

http://www.eipconline.com/

SERC Long Term Study Group Update

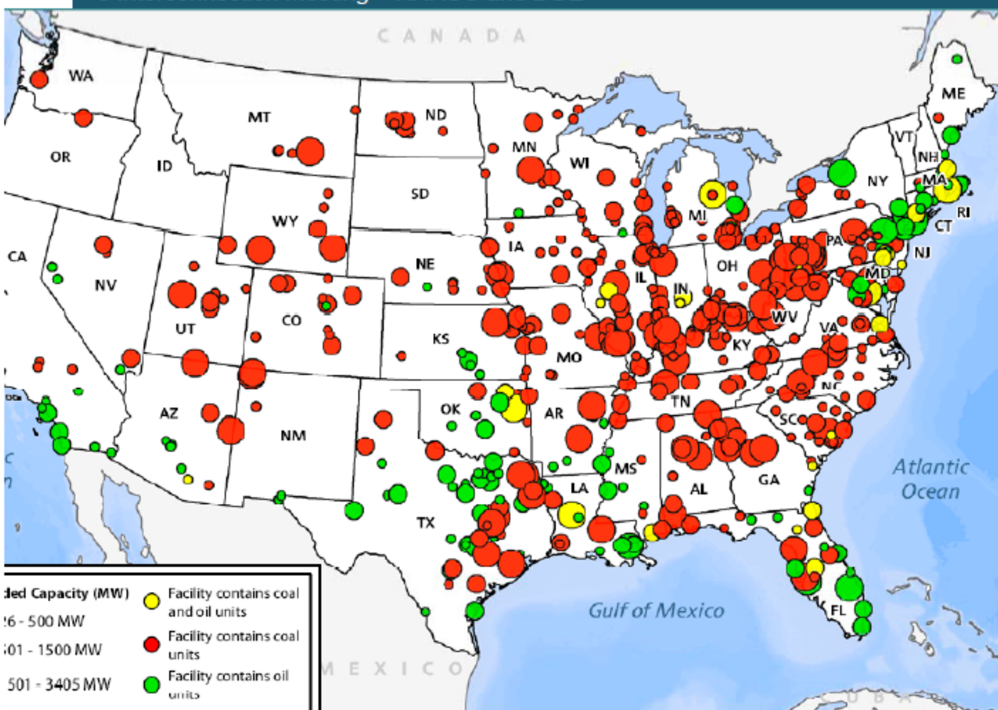
SERC Long Term Study Group

- Finishing report on 2016 MATS implementation impact study
- 2016 Summer Study Report available with FERC 715 filings
- 2013 model building process has begun

3 Interconnection Meeting – NARUC and DOE

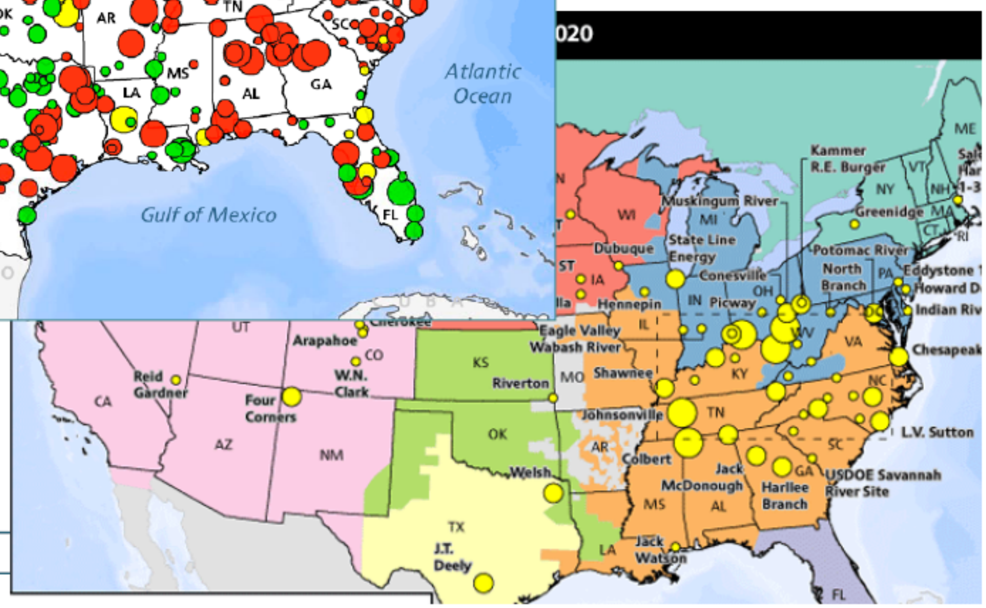
ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Coal and Oil Plants Affected by MATS Rule 2011



Announced Retirements (2011-2020)

September 2012



2016 LTSG STUDY RESULTS

SIGNIFICANT FACILITIES

Antioch 500/230 kV Transformers
The outage of either bank may limit Dominion-Duke and Gateway Subregion-VACAR transfers. The impedance difference between the banks causes the limit to be different for each bank. Duke Energy plans to upgrade these banks by 2014.

McGuire 500/230 kV Transformer
For the outage of the Woodleaf-Pleasant Garden 500 kV line, the McGuire 500/230 kV bank may limit Ameren-Duke transfers. The contingency's impact on the McGuire 500/230 kV transformer is directly related to the participation of McGuire Unit 1 in the transfer. Duke Energy has no plans for upgrades at this time, but will continue to monitor the facility.

SIGNIFICANT FACILITIES

McGuire – Riverbend Steam Station 230 kV 1/2

These lines may become overloaded during Progress East, LGEE, SCPSA, SGEG, SOCO and TVA to Duke transfers for outage of one of the parallel lines. Duke Energy plans to mitigate the issue through redispatching its generation at Lincoln CT Station.

Parkwood 500/230 kV Transformers

The outage of either parallel bank may limit Duke transfers to Ameren, Progress East, and Dominion; GTC and TVA transfers to Progress East; and GTC and TVA transfers to Dominion. An ancillary equipment upgrade can eliminate the lower transfer limits caused by limitations on bank 6. Future plans are to open the parallel bank for outage of either bank in order to mitigate the issue; however, Duke Energy continues to evaluate alternative future corrective actions.

SIGNIFICANT FACILITIES

Progress Energy identified no significant facilities resulting from this study.

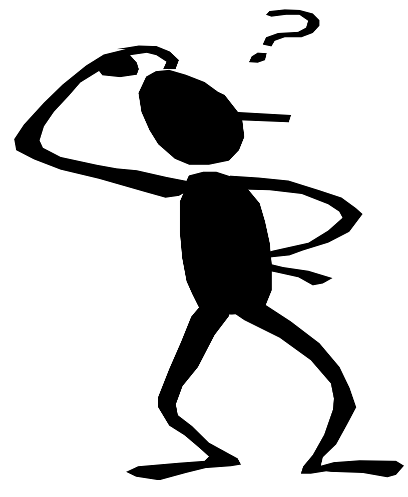
NERC Reliability Standards Update

- TPL “footnote b” remand – NERC BOT approved

- TPL - 003/4 – Stuck breaker and/or PS failure – NERC BOT approved

- BES definition guidance document – FERC approved

Questions ?



2013 TAG Work Plan

Rich Wodyka
ITP

2013 NCTPC Overview Schedule

Reliability Planning Process

- Evaluate current reliability problems and transmission upgrade plans
- Perform analysis, identify problems, and develop solutions
- Review Reliability Study Results

Enhanced Access Planning Process

- Propose and select enhanced access scenarios and interface
- Perform analysis, identify problems, and develop solutions
- Review Enhanced Access Study Results

Coordinated Plan Development

- Combine Reliability and Enhanced Results
- OSC publishes DRAFT Plan
- TAG review and comment

FERC Order 1000 Updates

TAG Meetings

1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter

2013 TAG Work Plan

January – February

- **2013 Study – Finalize Study Scope of Work**
  - ✓ Receive final 2013 Reliability Study Scope for comment
  - ✓ Review and provide comments to the OSC on the final 2013 Study Scope
  - ✓ Receive request from OSC to provide input on proposed Enhanced Transmission Access scenarios and interfaces for study
  - ✓ Provide input to the OSC on proposed Enhanced Transmission Access scenarios and interfaces for study

March 14th changed to April 16th

TAG Meeting

- **2013 Study Update**
  - ✓ **Receive a progress report on the Reliability Planning study activities and preliminary results**
- **Order 1000 Update**
  - ✓ **Receive report on the direction that the NCTPC is heading on the Order 1000 regional compliance**
  - ✓ **Receive an update on the overall Compliance Timeline highlighting when continued stakeholder involvement in the process will occur**

April - May - June

- **2013 Study - Technical Analysis, Problem Identification, and Solution Development**

  – **TAG will be requested to provide input to the OSC and PWG on the technical analysis performed, the problems identified as well as proposing alternative solutions to the problems identified**

  – **TAG will be requested to provide input to the OSC and PWG on any proposed alternative solutions to the problems identified through the technical analysis**

April - May - June

TAG Meeting scheduled for June 10th

- **2013 Study Update**
  - Receive a progress report on the Reliability Planning study activities and preliminary results
  - Receive update status of the upgrades in the 2012 Collaborative Plan
- **Order 1000 Update**
  - Receive an update on the Order 1000 regional compliance work and the discuss changes that will be coming in the regional compliance documents
  - Receive an update on the overall Compliance Timeline highlighting when continued stakeholder involvement in the process will occur

July - August - September

- **2013 Study Update**
  - Receive a progress report on the Reliability Planning study activities and preliminary results
- **2013 Selection of Solutions**
  - TAG will receive feedback from the OSC on any alternative solutions that were proposed by TAG members

July - August - September

TAG Meeting

- **2013 Study Update**
  - Receive a progress report on the Reliability Planning study activities and preliminary results
- **Order 1000 Update**
  - Receive an update on the Order 1000 regional compliance work and discuss the proposed changes that will be coming in the regional compliance documents
  - Receive an update on the overall Compliance Timeline highlighting when continued stakeholder involvement in the process will occur

October - November - December

- **2013 Study Update**

  - **Receive and comment on final draft of the 2013 Collaborative Transmission Plan report**

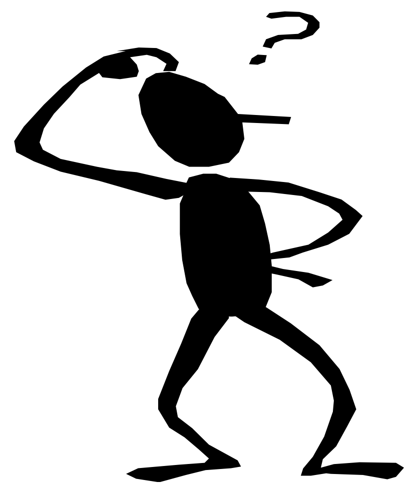
  - **Discuss potential study scope for 2014 studies**

October - November - December

TAG Meeting

- **2013 Study Update**
  - Receive presentation on the draft report of 2013 Collaborative Transmission Plan
  - Discuss potential study scope for 2014 studies
- **Order 1000 Update**
  - Receive an update on the Order 1000 regional compliance work

Questions ?



TAG
Open Forum Discussion

Comments or Questions ?