Reliability Review

Goals

- Overview of reliability
- Understand how reliability was defined, how we model it, how that relates to systems of the past (and present)
- Look forward: what to do for future systems with high renewable penetration?

System Outages

Two main types:

- Scheduled outage
  - "…typically done to perform maintenance or replacement of equipment… scheduled by operators to minimize the impact on the reliability of the system."
  - From: Power Generation, Operation, and Control, pg. 296 (3rd Ed)
- Forced outage
  - Random
  - Due to component failures
  - Due to mother nature
  - Due to malicious attacks

Do you agree with the statement in red? Why? Why not? If not, what would you propose?

System Reliability

- System must be able to survive from frequent contingencies
  - Transmission line failure
  - Transformer failure
  - Generator failure
- System must be able to handle typical forms of uncertainty
  - Load uncertainty
  - Area interchange
  - Loop flow
  - Renewables
- System operators protect against these by using preventive and corrective actions

Reliability Rules

- N-1 (mandatory):
  - The system must be able to avoid ***involuntary*** load shedding under any ***single*** element outage (generator, *non-radial* transmission)
    - N elements, must be able to survive the loss of 1 (N-1)
- N-k:
  - The system must be able to avoid involuntary load shedding under any ***k different*** element outages

N-1-1 Reliability

- N-1-1 reliability is not the same as N-2 reliability
- N-2 reliability means you have to protect your system against two simultaneous outages (losing two generators simultaneously)
- N-1-1 reliability means that, (some time) after a forced outage (and after you have recovered from that first outage over some period of time), you have your system back to being N-1 reliable (you lost a generator yesterday, you brought the system back to an N-1 secure stage, then you lose another generator)

Discussion

- Should we protect against only N-1? How about N-2?
- Do we protect against N-2 today?
- What is the general assumption that leads us to choose to enforce N-1?
- With renewables, how does this come into play?

Long Term Reliability Criterion

1 day in 10 years:

- One problem: different regions have different interpretations for what this metric means
- Generally used to specify that the length of time that generation is insufficient to meet demand should not exceed 1 day in 10 years

How will extreme weather events impact reliability? How to account for extreme events? Does this become harder to estimate with more renewables?

Long-Term Reliability Criteria

- Loss of Load Expectation (LOLE)
  - Indicates the expected loss of load over a duration (a year, 10 years)
- Loss of Load Probability (LOLP)
  - The proportion of days per year that there is insufficient generation to meet demand

- Commonly used standard: LOLP should be no more than 1 day in 10 years or 2.4 hours/year.

- Note that there is no mention, whatsoever, as to the size of the outage!

Break

Reliability Review

Contingency Analysis

Generator Contingency Modeling

- What happens when there is a generator contingency?
- How does the system respond?
- How do we want the system to respond? How can we dictate the response of the system?

- What about a deviation in load? Net load?

Transmission Contingency Modeling

- What happens when there is a transmission contingency?
- How does the system respond?
- How do we want the system to respond? How can we dictate the response of the system?

Contingency Analysis

- The evaluation of the system operating condition after a contingency (an outage) occurs
- Generally, this includes generator outages or transmission (lines or transformers) outages
- You remove the element, rerun PF or OPF, see if there is a problem

Contingency Analysis

Different potential assumptions when conducting contingency analysis:

- What time point are you modeling?
- Immediately following the contingency?
- A few minutes after the contingency?

- How does this deviate for a resource like a renewable that does not experience a one-time discrete disruption?

Participation Factors

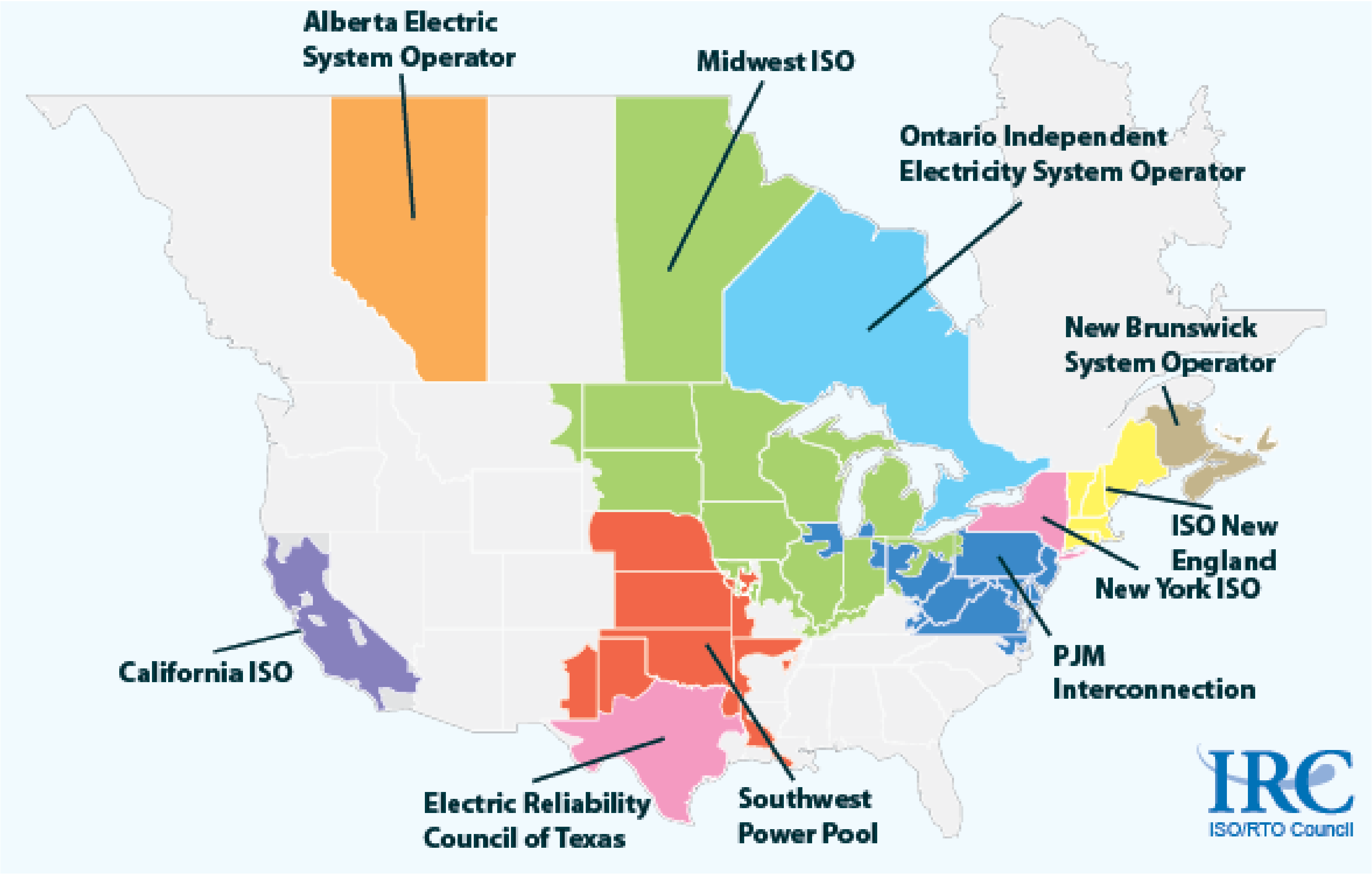
What is a participation factor?

What is the purpose of a participation factor?

What are some commonly used participation factors?

- Slack bus picks up the entire supply/demand imbalance
- Participation factor based on inertia
- Available reserve; ramp capability; capacity; current production; proximity to outage

ISONE


Alberta Electric
System Operator
Midwest ISO
Ontario Independent
Electricity System Operator
New Brunswick
System Operator
ISO New
England
New York ISO
PJM
Interconnection
California ISO
Electric Reliability
Council of Texas
Southwest
Power Pool
IRC
ISO/RTO Council

Break

Reliability Review

Notes from NERC Documentation

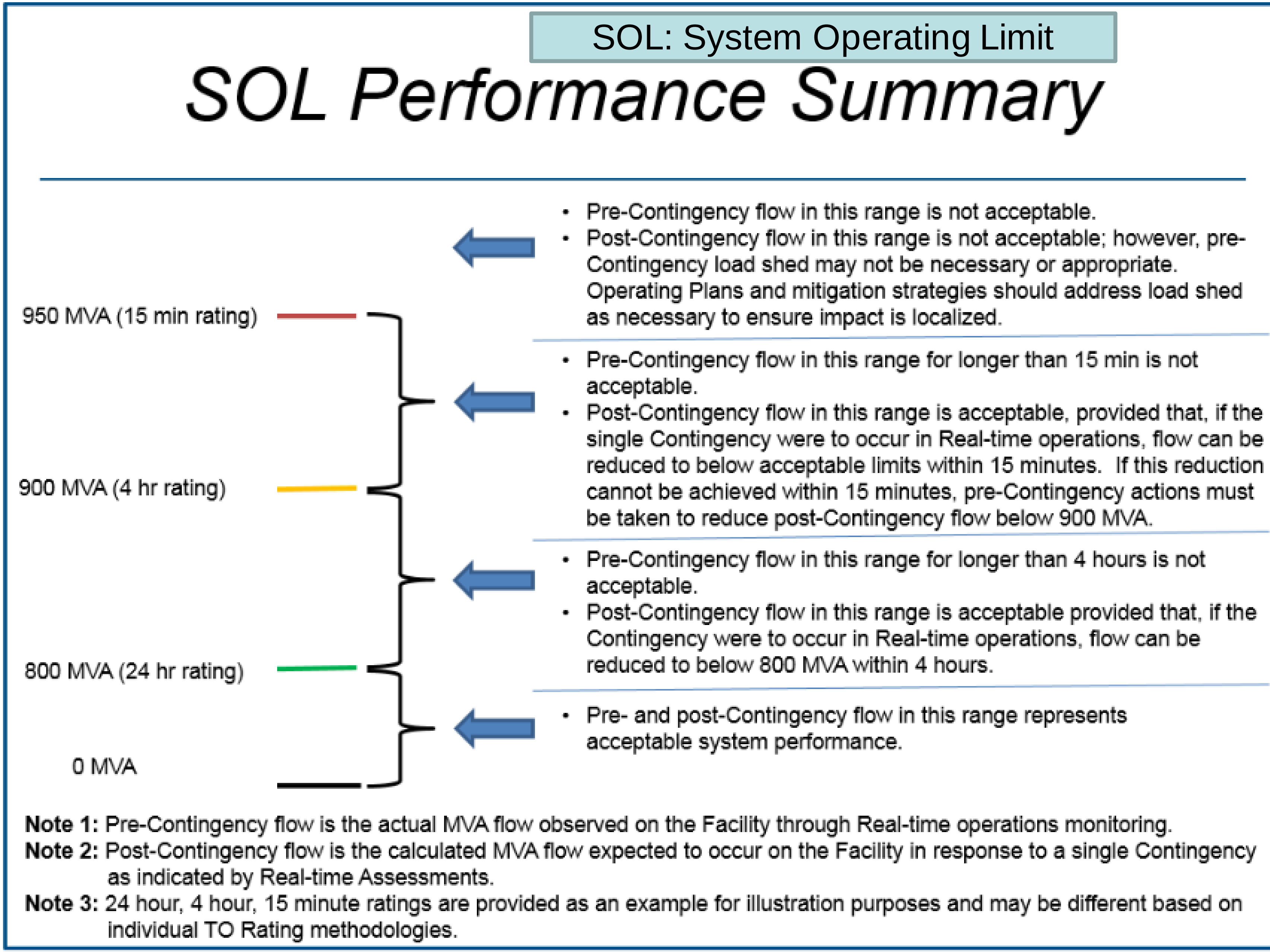


Figure 1. Facility Rating System Operating Limit Performance Summary

http://www.nerc.com/pa/Stand/Prjct201403RvsnstoTOPandIROStndrds/2014_03_fifth_posting_white_paper_sol_exceedance_20150108_clean.pdf

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No

http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-002-0b&title=System%20Performance%20Following%20Loss%20of%20a%20Single%20Bulk%20Electric%20System%20Element%20%28Category%20B%29&jurisdiction=United%20States

Table I. Transmission System Standards — Normal and Emergency Conditions

C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/	No No No No

http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-002-0b&title=System%20Performance%20Following%20Loss%20of%20a%20Single%20Bulk%20Electric%20System%20Element%20%28Category%20B%29&jurisdiction=United%20States

Standard IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments

B. Requirements and Measures

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Each Reliability Coordinator shall have evidence of a completed Operational Planning Analysis. Such evidence could include but is not limited to dated power flow study results.

http://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-008-2.pdf

Standard IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments

R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. [*Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

http://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-008-2.pdf

Standard IRO-008-2 – Reliability Coordinator Operational Analyses and Real-time Assessments

R4. Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-time Operations]*

M4. Each Reliability Coordinator shall have, and make available upon request, evidence to show it ensured that a Real-time Assessment is performed at least once every 30 minutes. This evidence could include but is not limited to dated computer logs showing times the assessment was conducted, dated checklists, or other evidence.

R5. Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. *[Violation Risk Factor: High] [Time Horizon: Same-Day Operations, Real-time Operations]*

http://www.nerc.com/pa/Stand/Reliability%20Standards/IRO-008-2.pdf

Standard IRO-005-2 — Reliability Coordination — Current Day Operations

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

http://www.nerc.com/files/IRO-005-2.pdf

Break

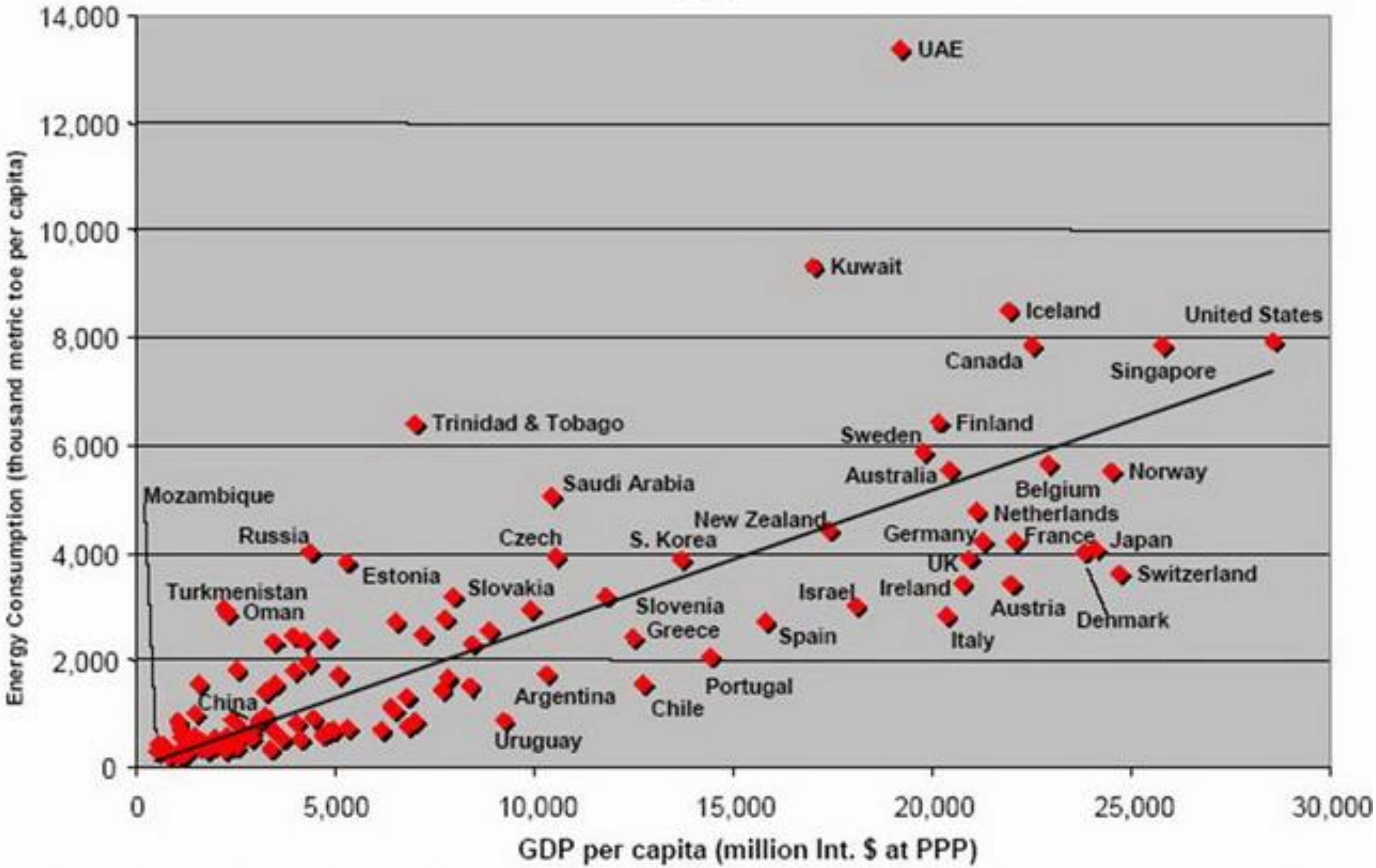
Reliability Review

2003 Northeast Blackout

Reliable Electric Energy

- National Academy of Engineering stated Electrification as the greatest achievement in the 20th Century
- Maintaining a continuous supply of electric energy is paramount for all of society
- Society expects high reliability
- Cost to society is high if there is a blackout
  - Northeast blackout of 2003 is estimated to cost: $6 - $10 Billion
  - Value of Lost Load (VOLL) is often used to estimate the economic impact of load shedding

GDP vs. Energy Consumption



Toe = ton of oil equivalent

PPP = purchasing power parity

August 14, 2003

10 Million
Canadians

45 Million USA

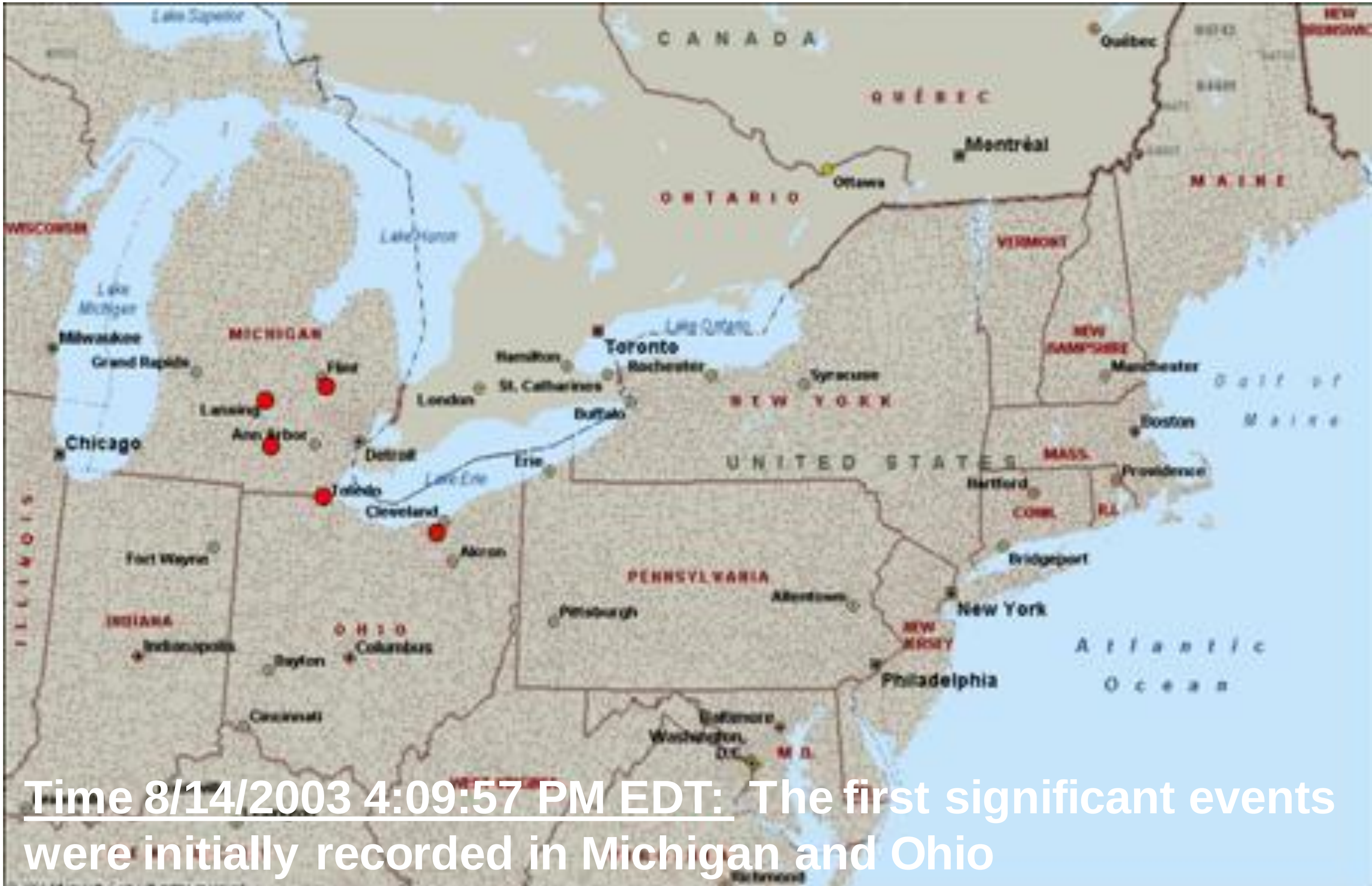
Estimated cost:

>$6B

11 deaths

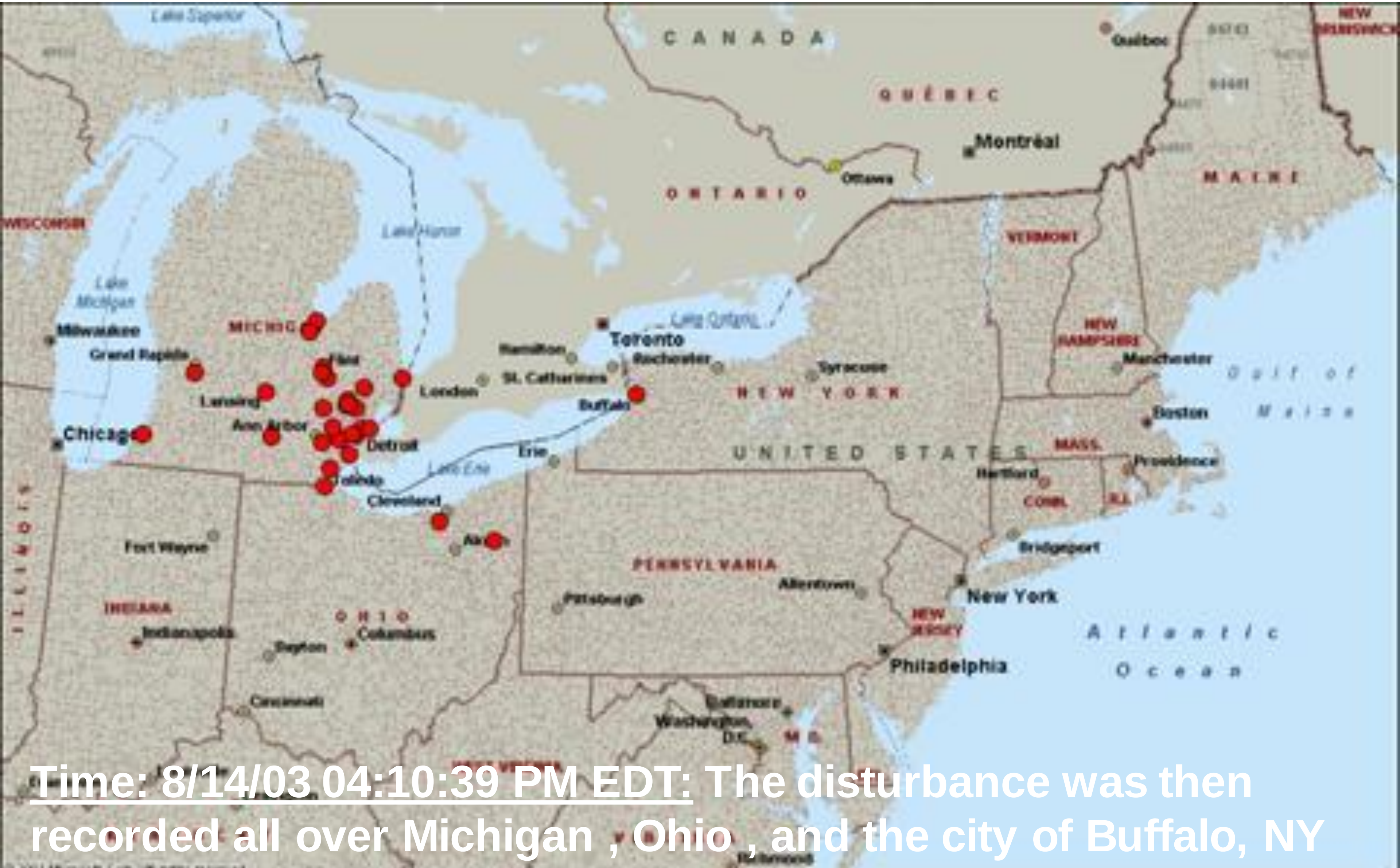
https://en.wikipedia.org/wiki/Northeast_blackout_of_2003#/media/File:Map_of_North_America,_blackout_2003.svg

The Northeast blackout of 2003



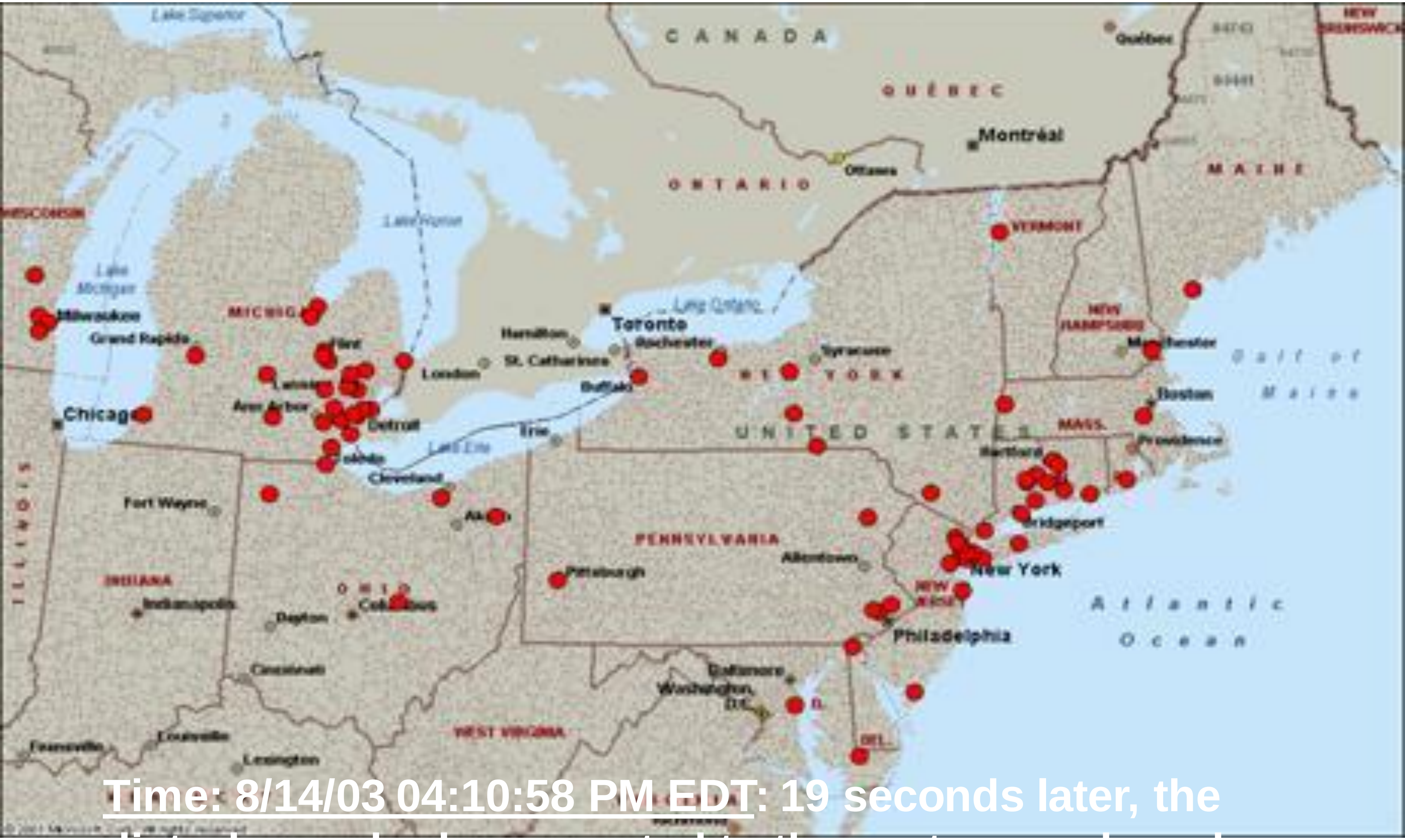
<u>Time 8/14/2003 4:09:57 PM EDT:</u> The first significant events were initially recorded in Michigan and Ohio

The Northeast blackout of 2003



<u>Time: 8/14/03 04:10:39 PM EDT:</u> The disturbance was then recorded all over Michigan , Ohio , and the city of Buffalo, NY

The Northeast blackout of 2003



Time: 8/14/03 04:10:58 PM EDT: 19 seconds later, the

The Northeast blackout of 2003

Main causes

- Tree trimming
- Failure of state estimator in MISO to model ‘external’ system changes
- Combination of heavy power exchanges, high reactive power flows, planned outages of transmission circuits and planned outage of a main generating facility (none of which are unusual)
- Operator error / training of MISO operators / imprudent operation of an Ohio utility (generation outages)
- Unplanned unit and line outages

http://www.pserc.org/Resources.htm#Description

Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. Apr. 5.

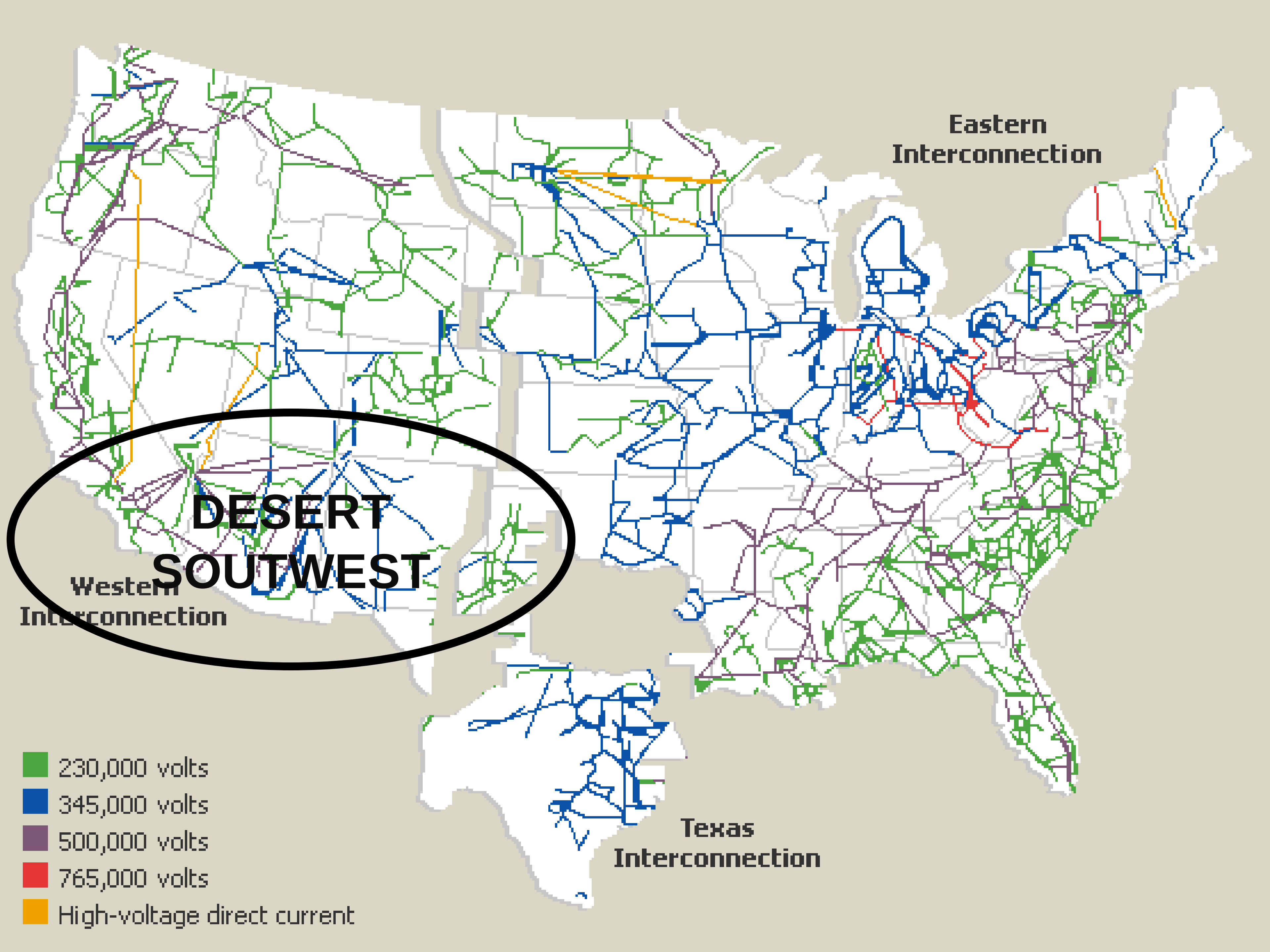
ECAR Investigation of August 14, 2003 Blackout By Major System Disturbance Analysis Task Force. Technical Report. February 2004.

Task Force Interim Report. Nov. 19. Presentation on the Interim Report. NERC. Dec. 1, 2003.

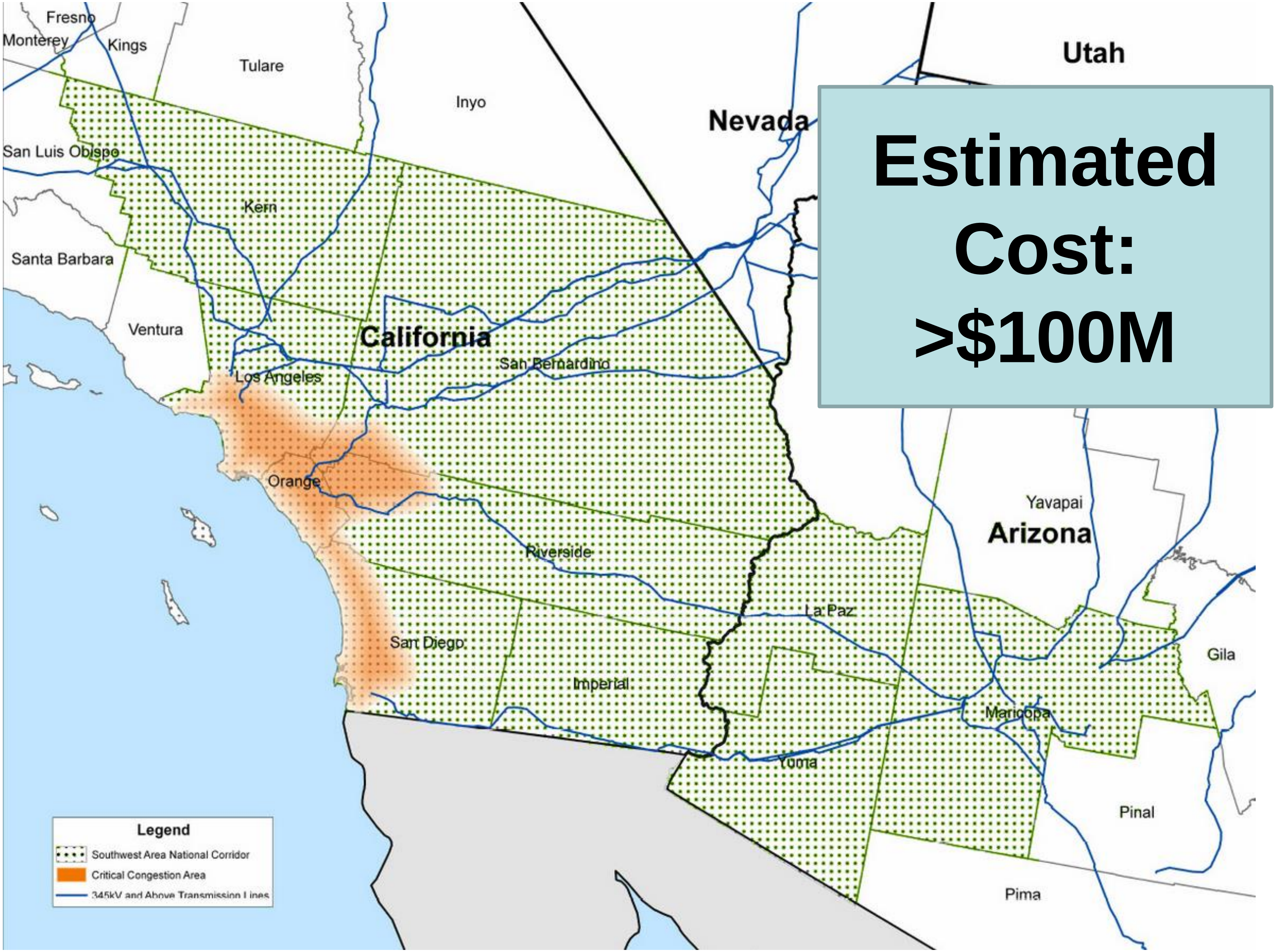
Blackout of 2003: Description and Responses. This presentation integrates material linked on this web page to provide an overview of the Blackout of 2003. An accompanying simulation of the Eastern Interconnection uses a 1998 system case to illustrate consequences of selected generation and line outage events along the Joint Task Force timeline. Updated 11/5. (Note: PDF versions are available.)

System Restoration. PJM. August 2003. This Power Point training presentation outlines reasons for blackouts and describes restoration processes

Desert Southwest Outage
September 8, 2011



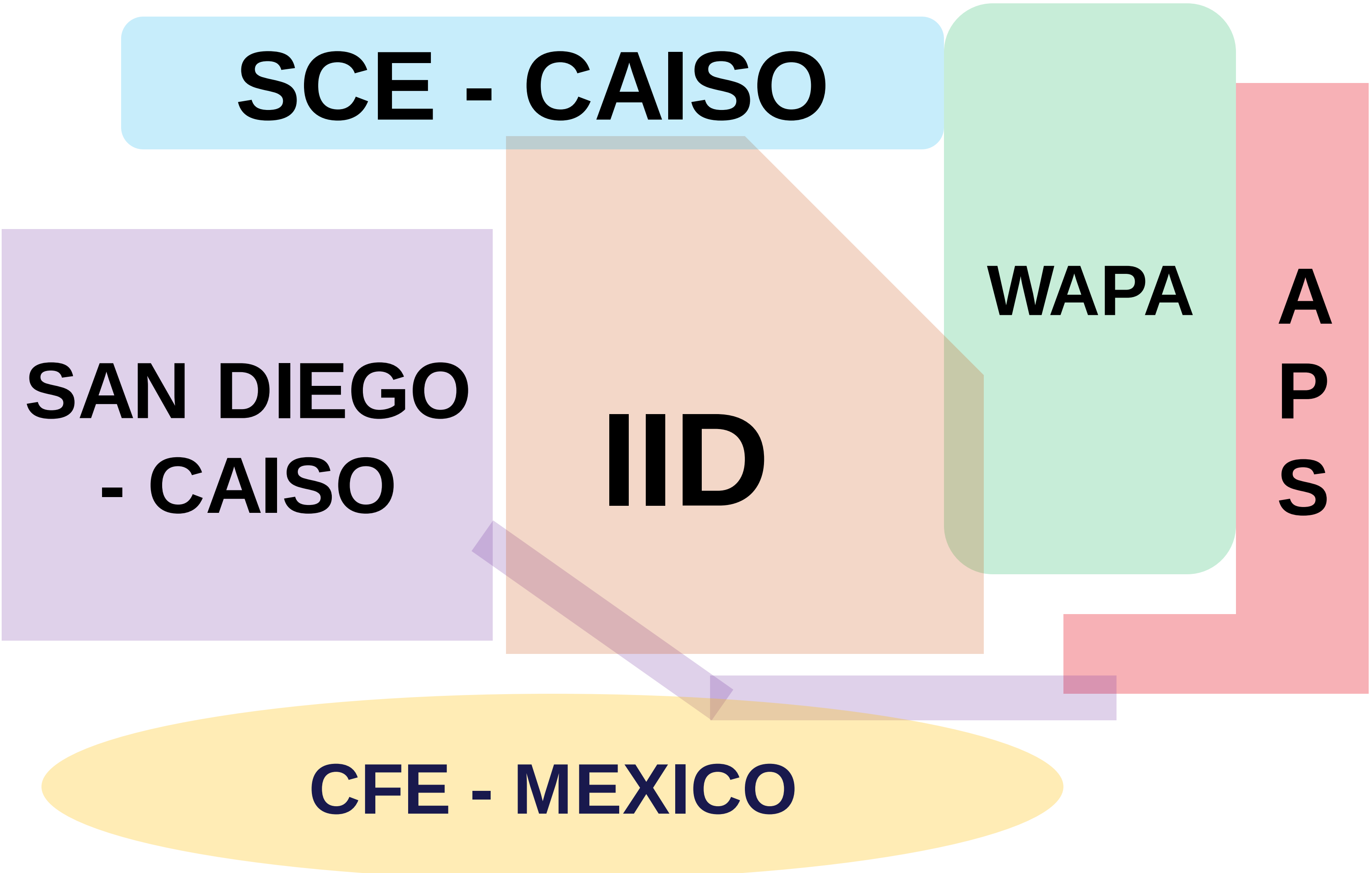
Eastern Interconnection
DESERT SOUTWEST
Western Interconnection
Texas Interconnection
230,000 volts
345,000 volts
500,000 volts
765,000 volts
High-voltage direct current



Estimated Cost: >$100M

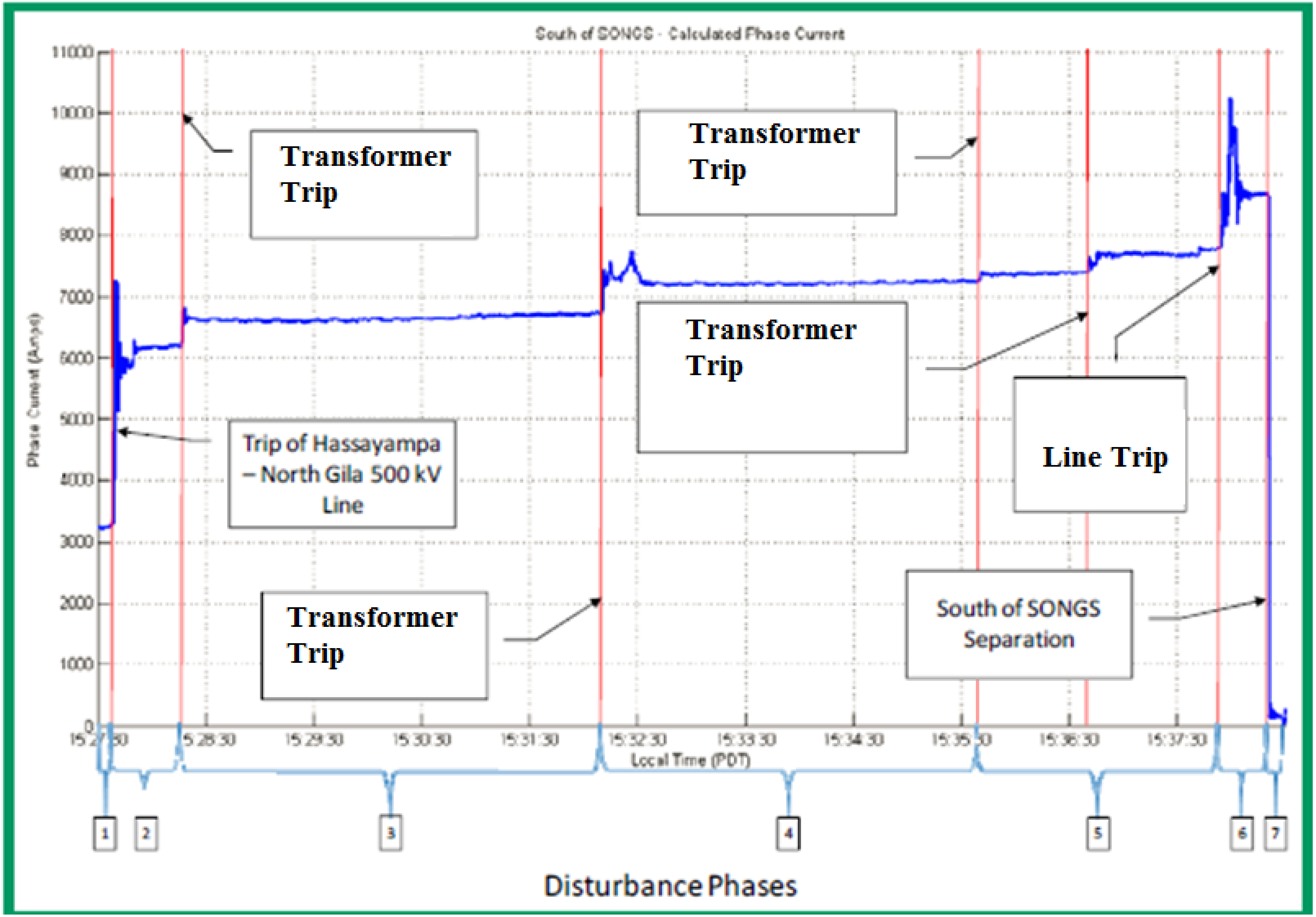
https://en.wikipedia.org/wiki/2011_Southwest_blackout#/media/File:NIETC-Southwest_area_corridor_US_2007.jpg

Desert Southwest System Overview



Timeline of events

Figure 4: Seven Phases of the Disturbance



Details from the report

- Transmission Owner, Transmission Operator and Generator Operator

The TO owns and maintains transmission facilities. The TOP is responsible for the real-time operation of the transmission assets under its purview. The TOP has the authority to take corrective actions to ensure that its area operates reliably. The TOP performs reliability analyses, including seasonal and next-day planning and RTCA, and coordinates its analyses and operations with neighboring BAs and TOPs to achieve reliable operations. It also develops contingency plans, operates within established SOLs, and monitors operations of the transmission facilities within its area. There are 53 TOPs in the WECC region. The following seven TOPs were affected by the event: APS, IID, WALC, CAISO, CFE, SDG&E, and SCE. The GOP operates generating unit(s) and performs the functions of supplying energy and other services required to support reliable system operations, such as providing regulation and reserve capacity.

Details from the report

The inquiry found that the affected TOPs' and BAs' procedures for conducting next-day studies and models used in these studies vary considerably. As explained more fully below, APS does not conduct next-day studies, relying, instead, on two sets of studies, conducted on a seasonal and annual basis, that consider a list of possible, predetermined contingency scenarios and provide plans to mitigate the contingencies if violated. Meanwhile, IID has a policy of conducting next-day studies each day, but between April and October of 2011, it failed to perform the required studies on a daily basis. All other affected TOPs conduct next-day studies, but they use models that do not

Details from the report

Thus, APS uses seasonal studies for non-Rated Paths and the manual for Rated Paths as tools in the day-ahead timeframe, without any additional analysis to validate that the tools remain valid for the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the base seasonal study was performed. APS maintains that these tools are sufficient for day-ahead purposes because they include the most severe contingencies identified in its system.

Details from the report

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Details from the report

The September 8th event also exposed entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the Western Interconnection. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect facilities and operations of external systems to ensure operation of the BPS in a secure N-1 state. Also, some entities' real-time tools are not adequate or operational to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the affected entities had been aware of real-time external conditions and run (or reviewed) studies on the conditions prior to the onset of the event, they would have been better prepared for the impacts when the event started and may have avoided the cascading that occurred.

Details from the report

One affected entity, APS, has State Estimator and RTCA capability, but neither tool is operational. As a result, APS has limited capability to monitor and operate its system to withstand potential real-time contingencies. Instead of using RTCA, APS relies on a set of previously studied contingencies and pre-determined plans to mitigate them. These studies are included in a manual that is created annually and usually updated several times a year.[78] By relying on pre-determined studies, APS cannot account and prepare for all potential contingency scenarios in real time. RTCA would provide APS with a more realistic analysis of its next potential contingency because the RTCA analysis is based on real-time conditions, as measured by State Estimator. Without RTCA, APS operators are not fully prepared to identify and plan for the next most critical contingency on its system.

RTCA would have allowed APS operators to study the impact of the loss of its H-NG. Although APS could have studied this contingency in its manual and seasonal studies, it could not have studied it *based on real-time operating conditions* that only State Estimator can provide. For example, APS's manual and seasonal studies did not

Fines

WECC and Peak stipulated to the facts in the agreement, and WECC agreed to pay the $16 million civil penalty, of which $3 million will be split evenly between the U.S. Treasury and NERC, and $13 million will be invested in reliability enhancement measures that go above and beyond mitigation of the violations and the requirements of the Reliability Standards. WECC and Peak also agreed to mitigation and reliability activities and to submit to compliance monitoring. WECC neither admits nor denies that its actions constituted violations of the Reliability Standards.

http://www.ferc.gov/media/news-releases/2015/2015-2/05-26-15.asp#.ViUy4Su1ZZg

Fines

In earlier settlements, Arizona Public Service Company, Imperial Irrigation District, California Independent System Operator Corporation, and Southern California Edison Company agreed to pay civil penalties of more than $21 million, with cash penalties of more than $7 million shared between the U.S. Treasury and NERC, and credits for enhancements to the reliability of the grid above and beyond the requirements of the Reliability Standards and required mitigation that included a utility-scale battery storage system, an innovative system for visualizing real-time system conditions, equipment to maintain system voltage in vulnerable areas, and additional system operators for the Reliability Coordinator, among other improvements.

http://www.ferc.gov/media/news-releases/2015/2015-2/05-26-15.asp#.ViUy4Su1ZZg