Transmission ITP

System Restoration

PJM State & Member Training Dept.

Objectives

At the end of this module the Student will be able to:

- Identify the different causes of some of the major blackouts that have occurred
- Describe some of the actions that could have been taken to prevent the blackouts
- Identify the effects significant blackouts have on society

History of Blackouts

Great Northeast Blackout: November 9, 1965

- A single transmission line from Niagara generating station tripped due to faulty relay setting
- Within 2.5 seconds, five other transmission lines became overloaded and tripped, isolating 1,800 MW of generation at Niagara Station
  - Generation then became unstable and tripped
- Northeast became unstable and separated into islands within 4 seconds
- Outages and islanding occurred throughout New York, Ontario, most of New England and parts of New Jersey and Pennsylvania

History of Blackouts

Great Northeast Blackout: November 9, 1965

- Most islands went black within 5 minutes due to generation/load imbalance
- Left 30 million people and 80,000 square miles without power for as long as 13 hours
- Estimated economic losses of over $100,000,000
- Led to the formation of Northeast Power Coordinating Council (NPCC) in 1966 and North American Electric Reliability Council (NERC) in 1968
- Cause: Human error of setting a protective relay incorrectly

History of Blackouts

Great Northeast Blackout
November 9, 1965

History of Blackouts

PJM Blackout: June 5, 1967

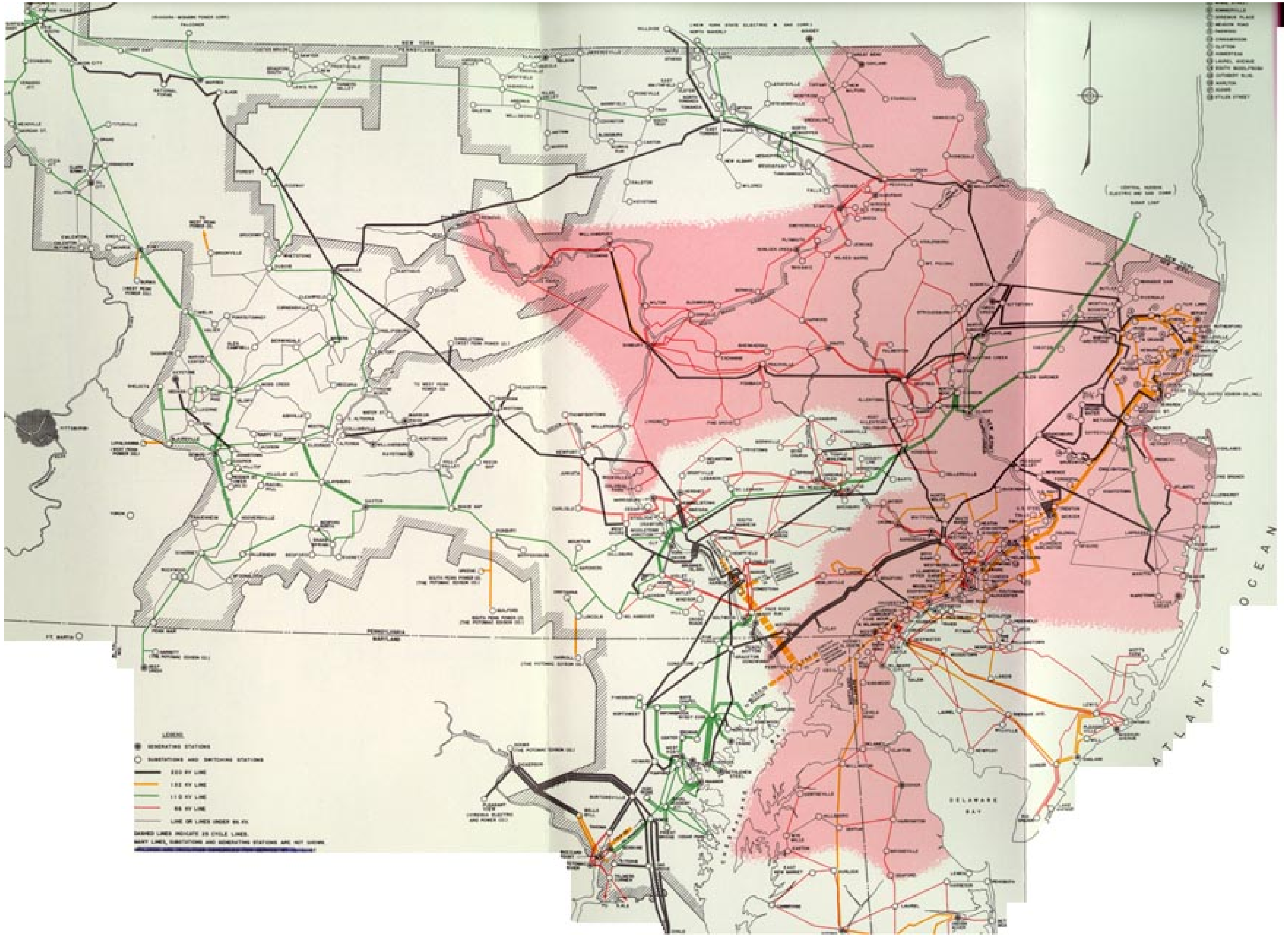
- 3 major system improvements had been delayed beyond the beginning of the summer
  - Oyster Creek nuclear station
  - Keystone #1 unit
  - Keystone 500 kV transmission
- Loss of Nottingham-Plymouth line and Muddy Run Generation
  - Conductor sag
  - First time 4 MR units operated at the same time
- Loss of Brunner Island #2 - Heavy loads and low voltages

History of Blackouts

PJM Blackout: June 5, 1967

- Loss of S. Reading-Hosensack, Brunner Island #1 Unit
- Cascading trippings of transmission resulted in system separation
- Load in affected area exceeded the scheduled operating capacity by more than 700 MW
- System stabilized at 53 Hertz
- Load shedding may have saved the island
  - No under-frequency load shedding was installed at the time
- All protective relaying worked properly
- Led to more extensive voltage monitoring and UPS for instrumentation and control

History of Blackouts



History of Blackouts

Tokyo Blackout: July 23, 1987

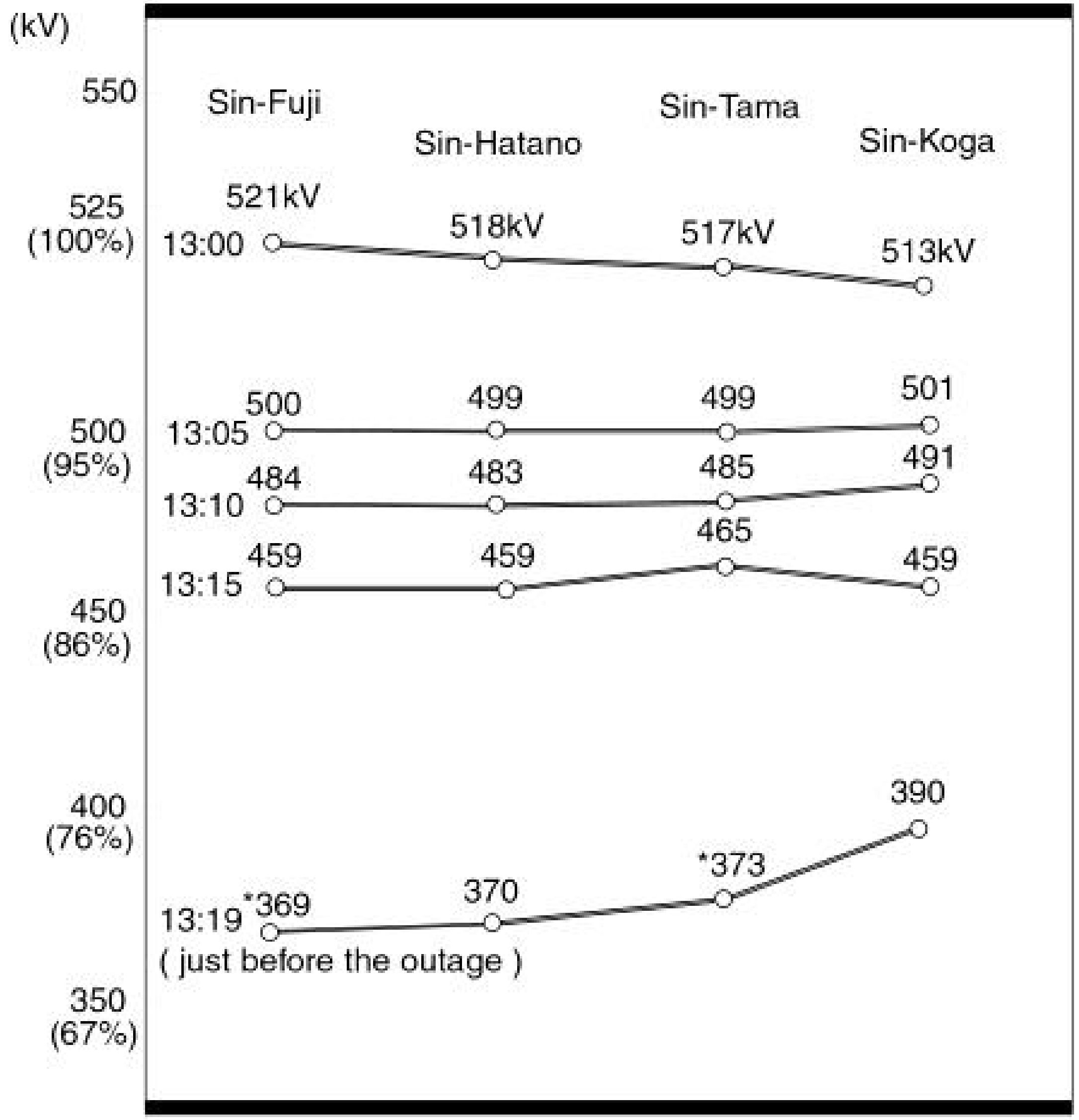
- Result of a voltage collapse
- After lunch load pickup came in at a rate of 400 MW/minute
  - Only sustained for a few minutes
- At 1300, 500 kV voltages were 513 - 521 kV
- At 1310, 500 kV voltages were 483 - 491 kV
- At 1319, 500 kV voltages were 369 - 390 kV
- At this point, the system collapsed
  - 8168 MW of load and 2.8 million customers lost
- Blackout took 19 minutes to develop and 3 hours, 20 minutes to restore

History of Blackouts

Tokyo Blackout

July 23, 1987

Fig. 4 Voltage Drops at Main Substations



* = the estimated value

History of Blackouts

Northeast/Midwest United States and Canadian Blackout: August 14, 2003

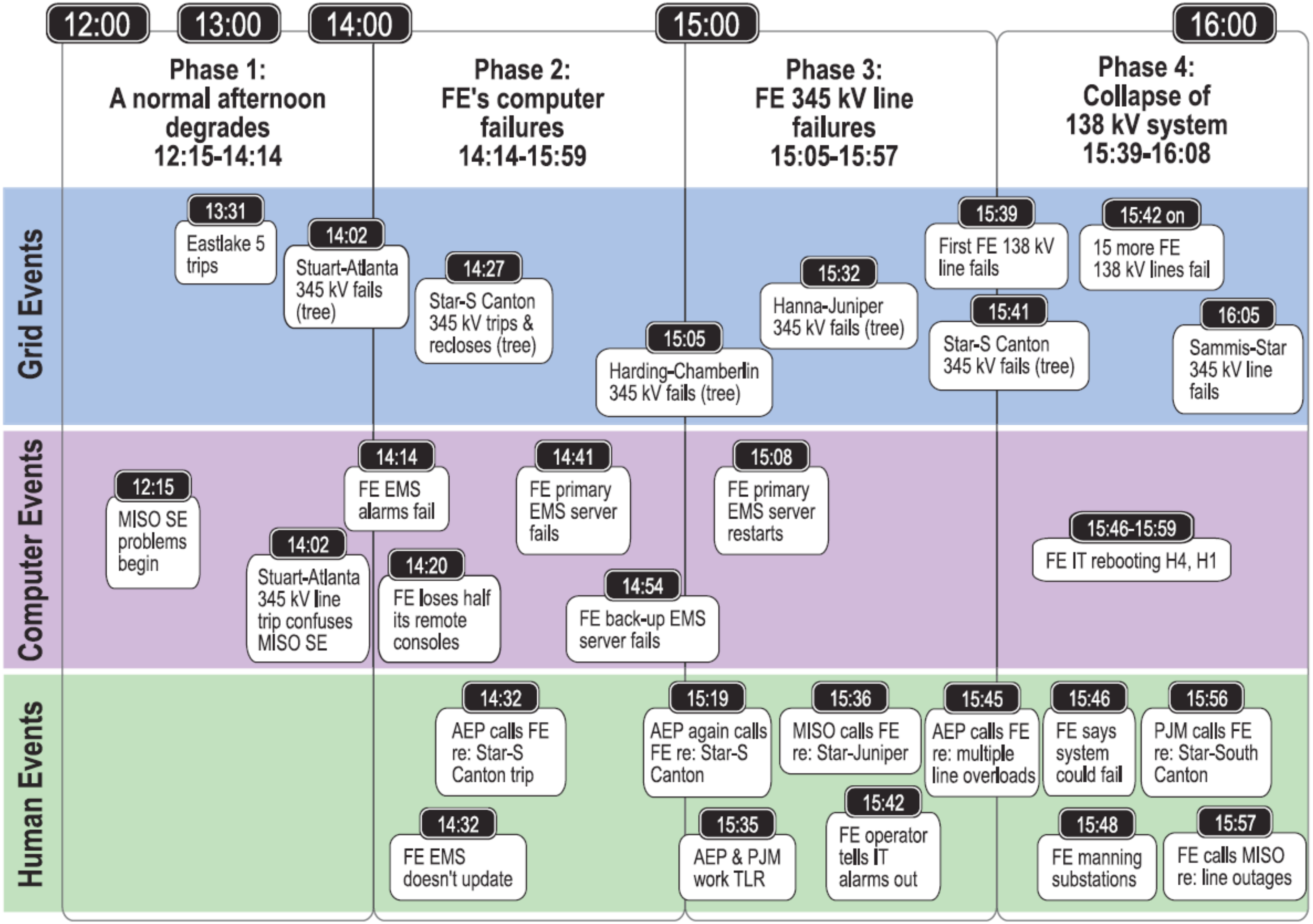
- FE-ATSI was having issues with their EMS
- IT was aware of and working on the issues, but did not communicate with the operators on shift
- Alarm processing had stopped and the operators (and IT) were unaware that they would not be getting SCADA alarms for events
- 345kV and 138 kV line trippings occurred in the FE-ATSI territory and the EMS did not alarm, and were not represented on the FE-ATSI SCADA System

History of Blackouts

Northeast/Midwest United States and Canadian Blackout: August 14, 2003 *(Con't.)*

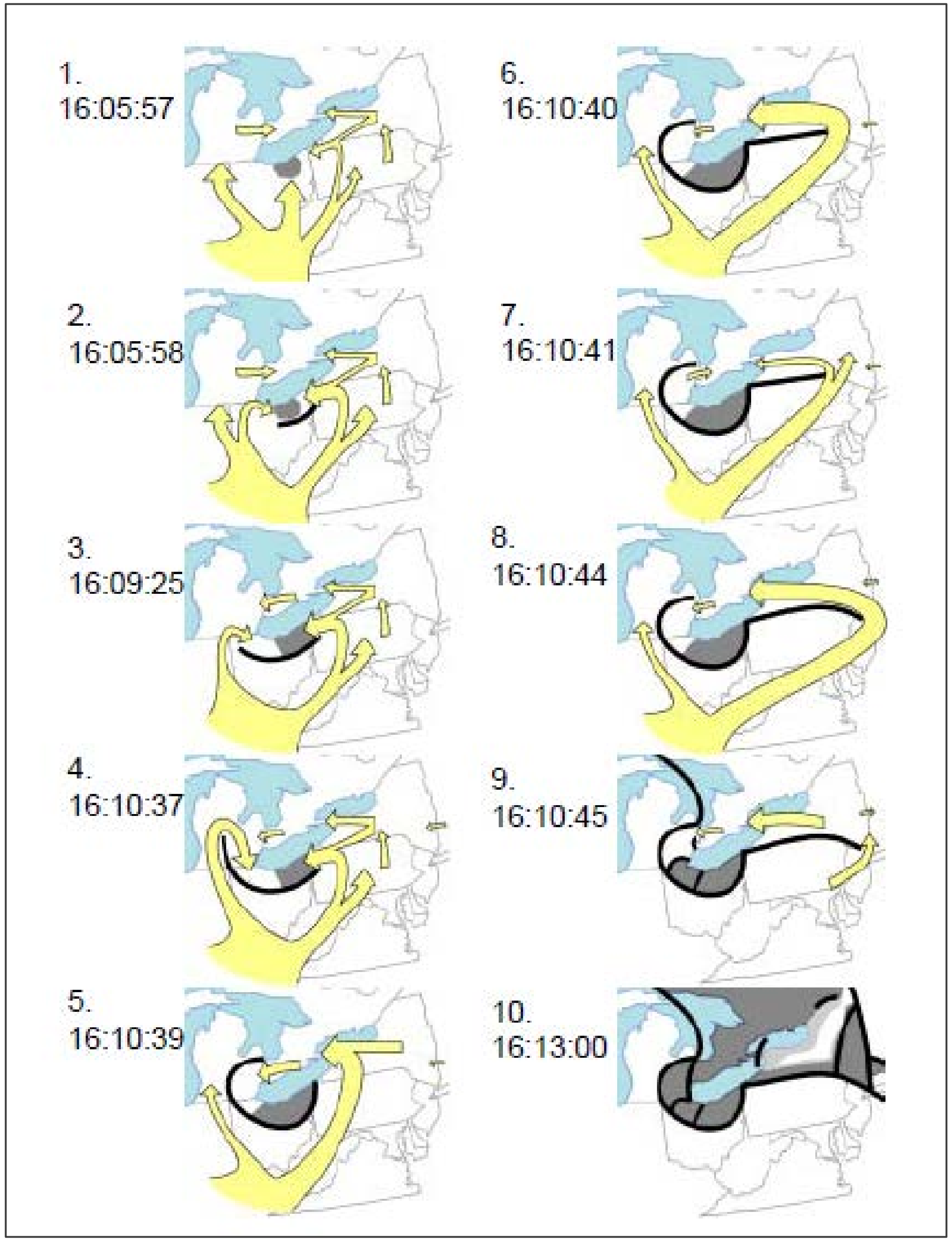
- PJM and MISO saw the resultant flow changes and attempted to question FE-ATSI about the system conditions
- Cascading line trips led to a voltage collapse scenario centered around the Cleveland area
- The low voltages and line trippings caused generating units to begin tripping offline
- The incidents of line trippings, unit trippings, and low voltages expanded throughout the Northeast and into Canada
- The entire event lasted less than 8 minutes

History of Blackouts



History of Blackouts

Cascade Sequence



Legend

Yellow arrows represent the overall pattern of electricity flows.

Black lines represent approximate points of separation between areas within the Eastern Interconnect.

Gray shading represents areas affected by the blackout.

History of Blackouts

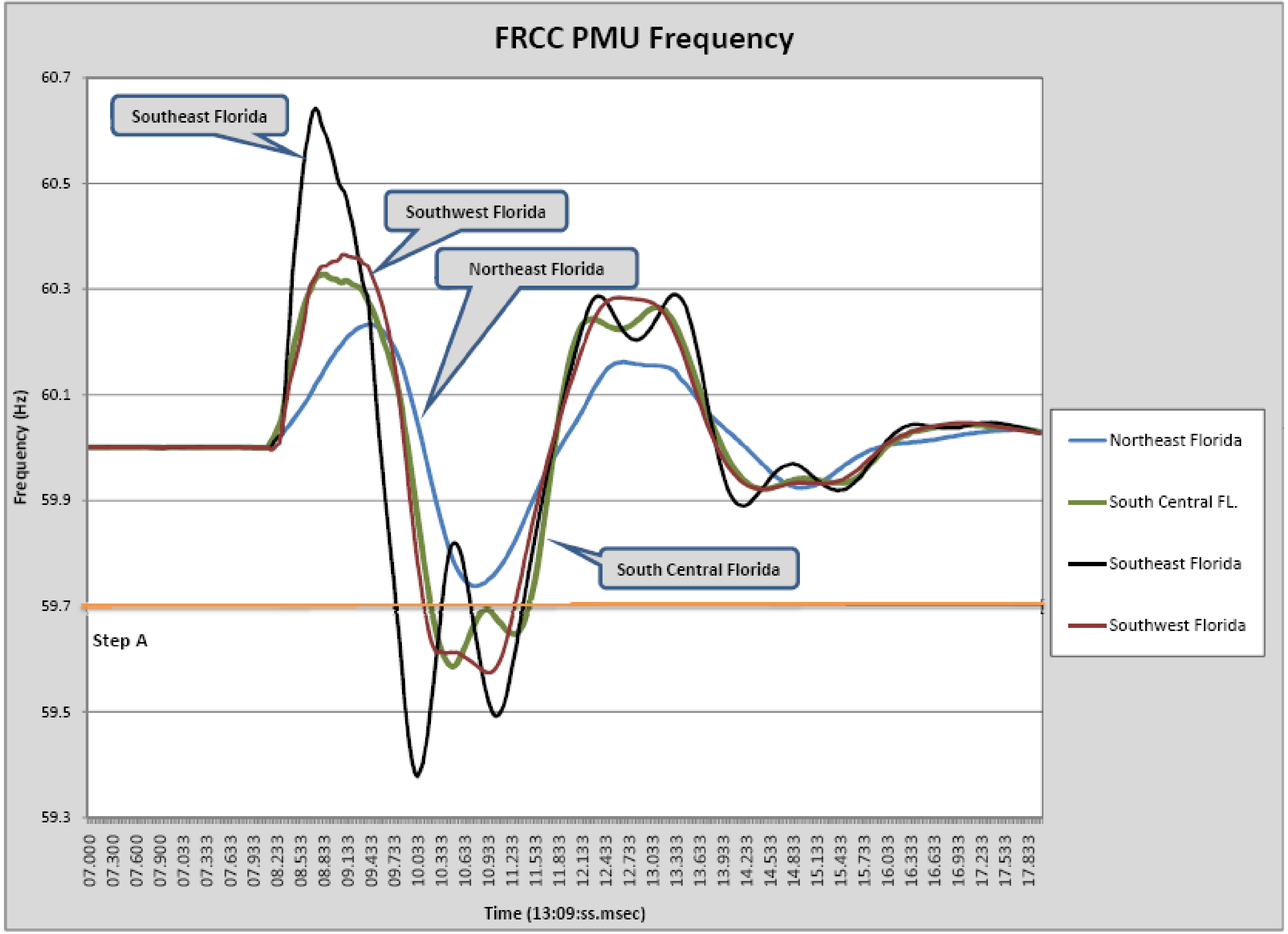
Florida Blackout: Tuesday, February 26, 2008 at 13:09

- Delayed clearing of 3-phase 138kV switch fault at Florida Power and Light, a Miami-area substation (1.7 seconds)
  - Resulted in loss of:
    - 22 transmission lines
    - 1350 MW of load in area of fault
    - 2300 MW of distribution load across southern Florida as a result of under frequency load shedding (59.7 Hz)
    - 2500 MW of generation in area of fault
      - Including 2 Turkey Point Nuclear Units
    - Additional 1800 MW of generation across the region

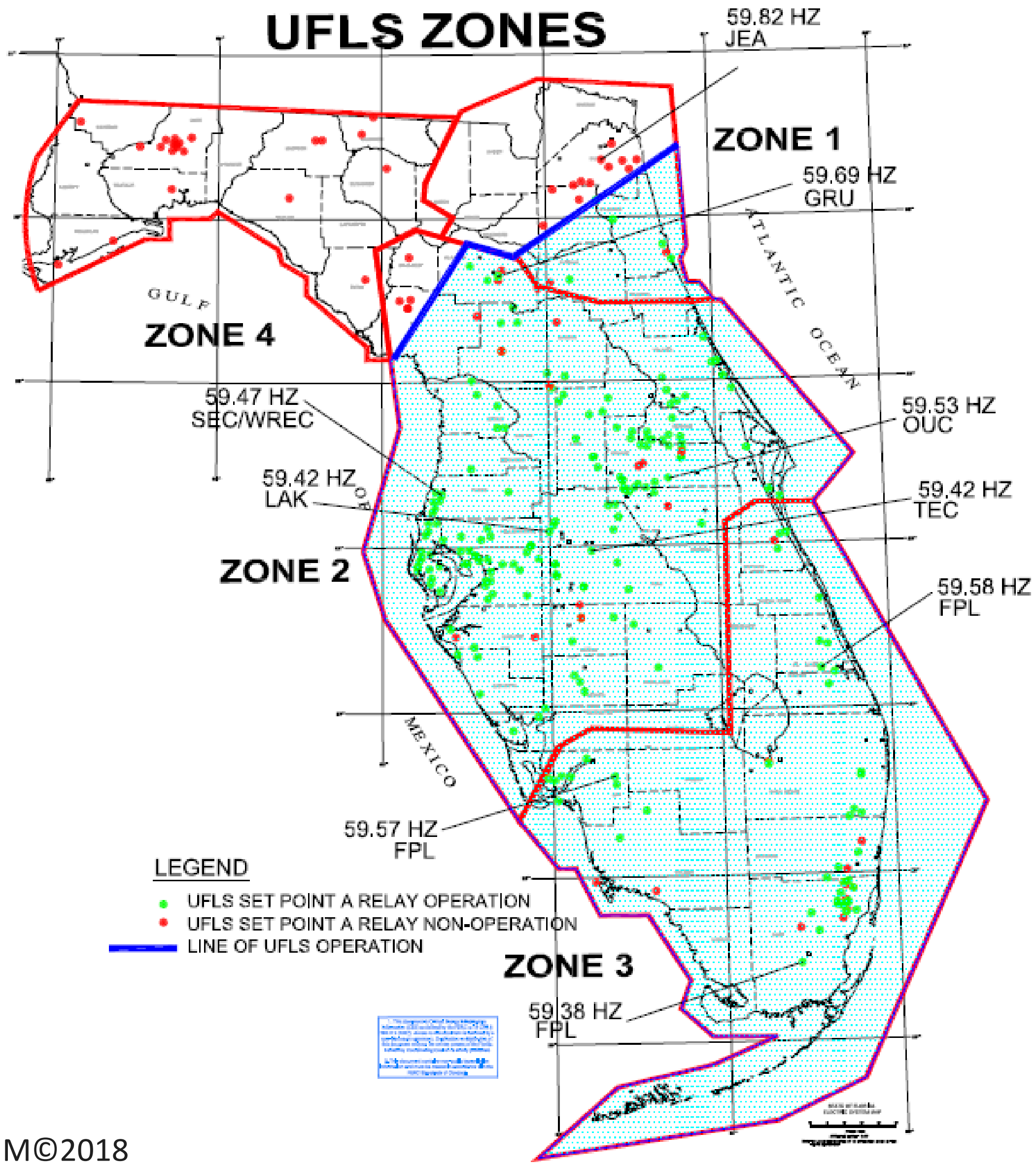
History of Blackouts *(con't)*

- Florida remained interconnected to Eastern Interconnection throughout the event
  - Majority of load restored within 1 hour
    - All customers restored within 3 hours
  - Final report contained 26 recommendations

History of Blackouts



History of Blackouts



FRCC Underfrequency Load Shedding (UFLS) Requirements

1. All load serving members of the FRCC must install automatic underfrequency relays which will disconnect 56% of their customer demand in accordance with the following schedule.

UFLS Step	Frequency - (hertz)	Time Delay [1] - (seconds)	Amount of Load (% of member system)	Cumulative Amount of Load (%)
A	59.7[2]	0.28	9	9
B	59.4	0.28	7	16
C	59.1	0.28	7	23
D	58.8	0.28	6	29
E	58.5	0.28	5	34
F	58.2	0.28	7	41
L	59.4	10.0	5	46
M	59.7	12.0	5	51
N	59.1	8.0	5	56

History of Blackouts

- Local primary and backup relay protection removed from service on energized equipment while troubleshooting equipment malfunction
- Other failed indicators provided false information that led to this decision
  - Insufficient procedures
  - Oversight of field test personnel
    - Approval between field personnel and system operators when protection systems removed from service
    - Communication between control room personnel and control room supervision when protection systems removed from service
    - Protection system changes recommended
    - Training on infrequently received EMS alarms and unusual communication
    - 3-Part communication not consistently used during restoration led to minor confusion
    - Enhanced restoration procedures for under frequency load shed events
    - Under frequency load shed prevented more widespread event

History of Blackouts

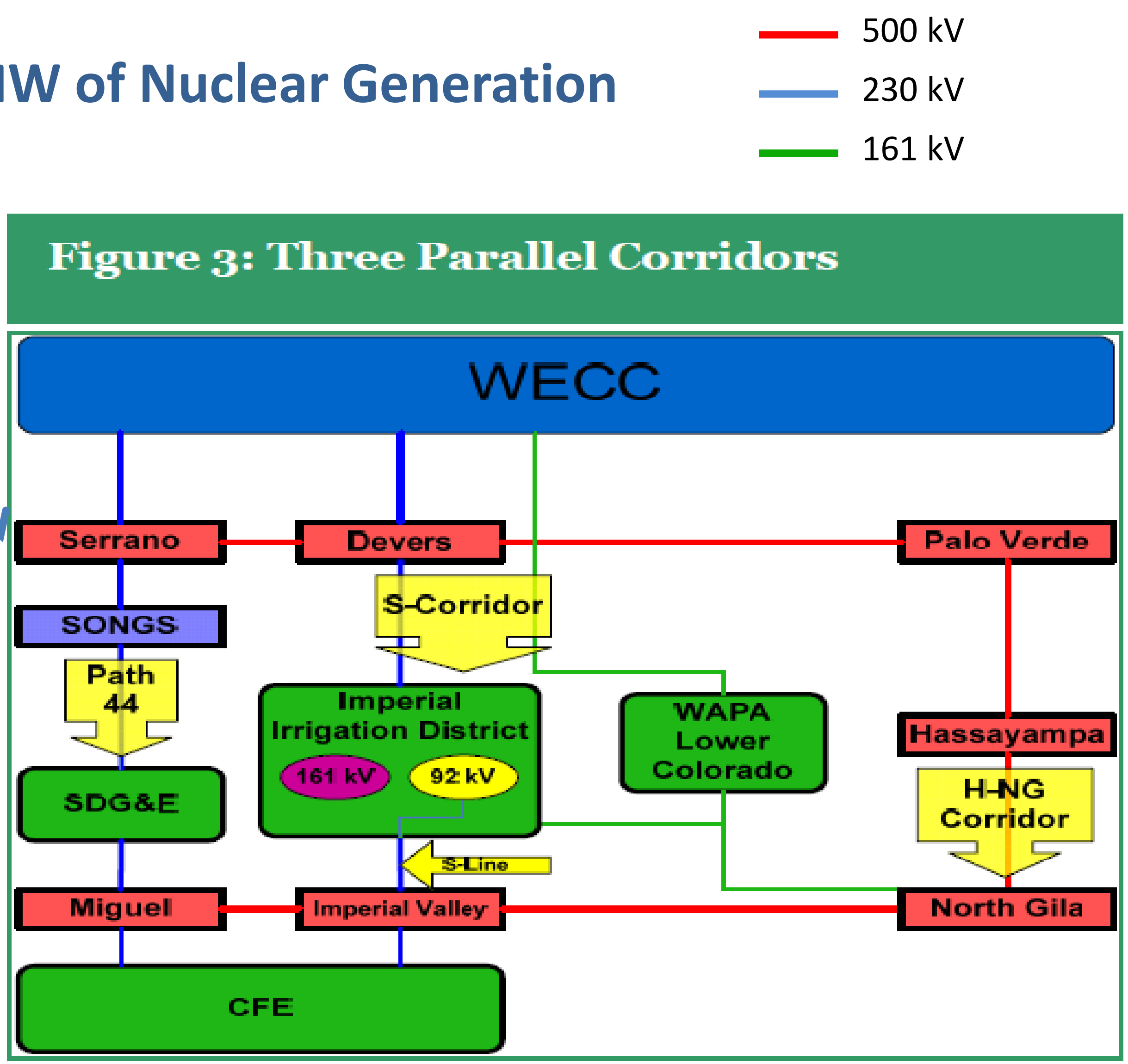
Arizona-South California Outages: September 8, 2011

- Late in the afternoon, an 11-minute system disturbance occurred in the Pacific Southwest leading to:
  - Cascading outages
  - Approximately 2.7 million customers without power
- The outages affected parts of Arizona, Southern California, and Baja California, Mexico, and all of San Diego
- The disturbance occurred near rush hour on a business day, snarling traffic for hours

History of Blackouts

- The affected line:
  Hassayampa-N.Gila (H-NG)
  500 kV line,
  Arizona Public Service (APS)
  - A segment of the Southwest Power Link (SWPL)
    - A major transmission corridor
    - Transports power in an east-west direction
    - Generators in Arizona
    - Runs through the service territory of Imperial Irrigation District (IID), into the San Diego area

2200 MW of Nuclear Generation



History of Blackouts

Arizona-South California Outages

- A technician missed two steps in a switching scheme, causing:
  - Flow redistributions, voltage deviations, and overloads
  - Resulted in transformer, transmission line, and generating unit trippings
  - Initiated automatic load shedding
- Path 44 carried all flows into the San Diego area, and parts of Arizona and Mexico
- The excessive loading on Path 44 initiated an inter-tie separation scheme at SONGS, leading to the loss of the SONGS nuclear units

History of Blackouts

Arizona-South California Outages *(con't.)*

- During the 11 minutes of the event, the WECC Reliability Coordinator issued no directives
- Only limited mitigating actions were taken by the TOP's of the affected areas
- All affected entities had access to power from their own or neighboring systems and, therefore, did not need to use "black start" plans
- Although there were some delays in the restoration process due to communication and coordination issues between entities, the process was generally effective

History of Blackouts

Arizona-South California Outages *(con't.)*

- Significant findings included:
  - Protection settings and coordination
  - Situational awareness of the operators
  - Lack of clarity among all involved operators concerning responsibilities for restoration efforts

History of Blackouts

Australian Blackout

- AEMO operates Australia's National Electricity Market (NEM) and the interconnected power system in Australia's eastern/south-eastern area

The National Electricity Market (NEM):

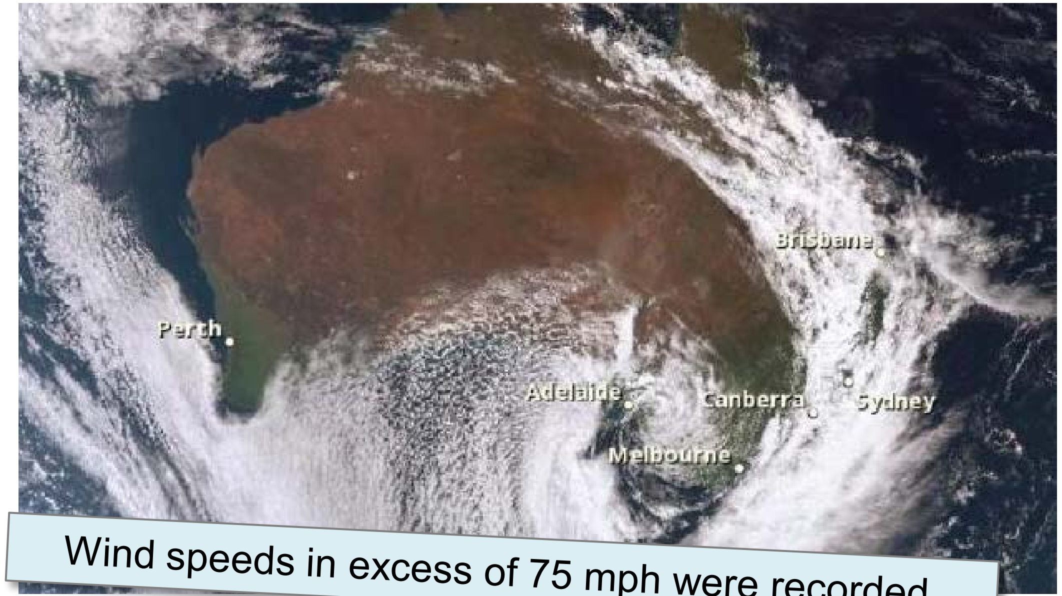
- Incorporates around 25,000 miles of transmission lines and cables
- Supplies 200 terawatt hours of electricity to businesses and households each year
- Supplies around 9 million customers
- Generates 45,000 MW
- Trades $7.7 billion in the NEM in 2014-15

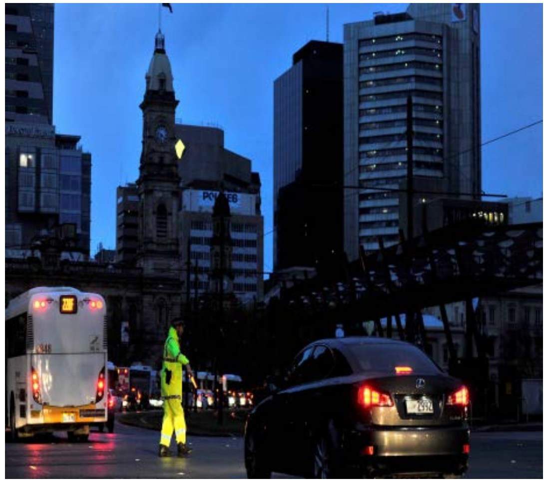
Heywood Interconnector:
275 kV transmission line that permits power flow between South Australia and Victoria

https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM (2017)

History of Blackouts

September 28th, 2016





Wind speeds in excess of 75 mph were recorded.

Extreme weather resulted in the loss of multiple transmission lines and 445 MW of generation of nine wind farms.

The combined loss of wind generation and interchange resulted in the interruption of 1,895 MW resulting in a system blackout.

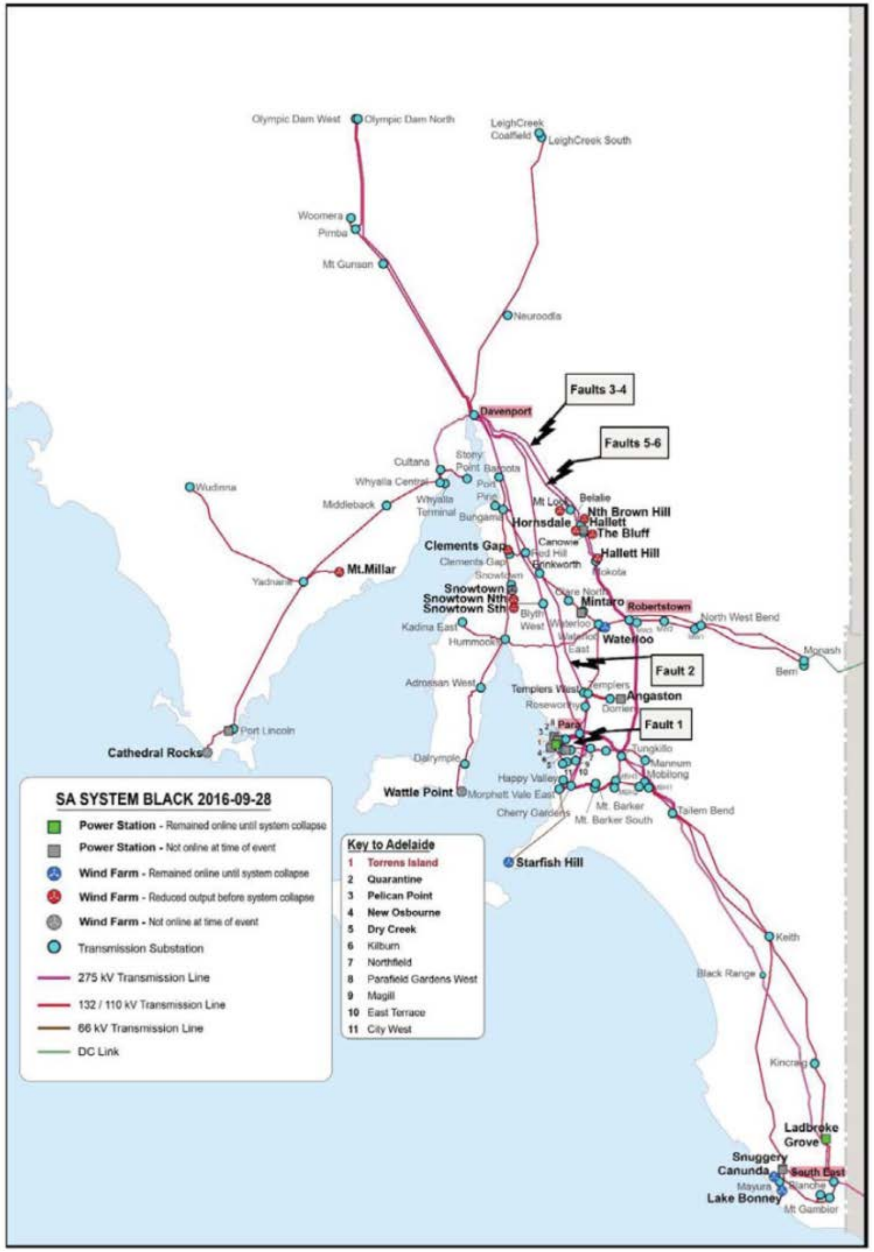
Total customers outaged = 850,000

History of Blackouts

http://www.abc.net.au/news/2016-09-29/political-storm-erupts-after-sa-loses-power/7891098

History of Blackouts

- 6 transmission line faults occurred
  - Major voltage dips on the network over a 2-minute period
- The Murraylink HVDC tie line tripped due to under-voltage conditions
- The Victoria-Heywood Interconnector tripped, the remaining 275KV tie line to Victoria
- South Australia region blacked out



AEMO (2016)

History of Blackouts

Transmission Line Faults

Fault number	Time	Details
1	16:16:46	Fault on Northfield-Harrow 66kV feeder in the Adelaide metropolitan area. Trip and successful auto-reclose. Voltage dipped to 85% at Davenport.
2	16:17:33	Two phase to ground fault on the Brinkworth – Templers West 275kV transmission line. No reclose attempt. Voltage dipped to 60% at Davenport.
3	16:17:59	Single phase to ground fault on the Davenport – Belalie 275kV transmission line. Faulted phase successfully auto-reclosed. Voltage dipped to 40% at Davenport.
4	16:18:08	Single phase to ground fault on the Davenport – Belalie 275kV transmission line. No auto-reclose attempted as fault is within 30 seconds of the previous fault Line opened on all three phases and remained out of service. Voltage dipped to 40% at Davenport.
5	16:18:13	Single phase to ground fault on the Davenport – Mt Lock 275kV transmission line. Voltage dipped to 40% at Davenport.
	16:18:14	Single phase to ground fault on the Davenport – Mt Lock 275kV transmission line due to unsuccessful auto-reclose. Fault still on line. Line opened on all three phases and remained out of service. Voltage dipped to 40% at Davenport.

AEMO (2016)

History of Blackouts

Wind Farm Response

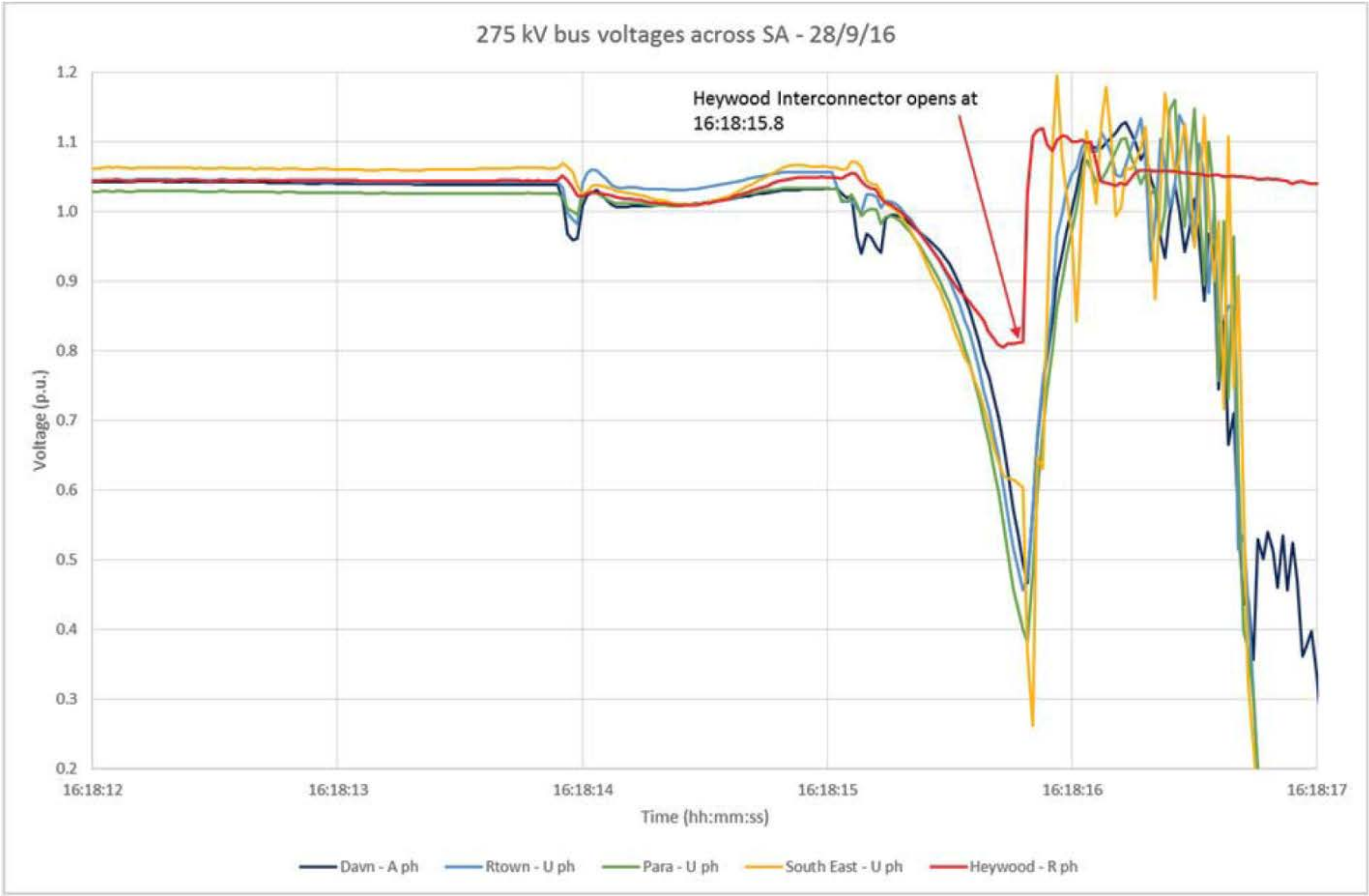
- 445 MW of wind generation tripped offline due to relay activation, designed to protect the turbines against
  - Under voltage conditions (ride-through mode)
  - Wind operators were aware of these limitations but the grid operator was not

Wind farm	Pre-set limit to ride-through events in 120 seconds	Number of times wind turbines activated ride-through mode	Last state of wind turbines prior to system voltage collapse	Output pre-event at 16:18:07 [MW]	Output just prior to separation at 16:18:15.4 [MW]
Canunda	9	1	Operational	27.7	27.2
Lake Bonney 1	42618	0	Operational	77.7	76.5
Lake Bonney 2,3	9	0	Operational	171.9	158.7
Waterloo	9	5	Operational	96.6	72.9
				Expected MW Reduction	38.6
Clements Gap	2	3	Disconnected	14.5	-0.5
Hallett	2	3	Most turbines disconnected	34.5*	1.7*
Hallett Hill	2	3	Most turbines disconnected	41.3*	19.5*
Mt Millar	Not known	5	Stopped Operation	67.0**	2.8**
North Brown Hill	2	3	Most turbines disconnected	85.5	11.0
Hornsdale	5	6	Stopped Operation	83.9	-1.1
Snowtown North	5	6	Stopped Operation	65.5	-0.8
Snowtown South	5	6	Stopped Operation	42.1	-1.2
The Bluff	2	3	Most turbines disconnected	41.9	-0.3
				Unexpected MW Reduction	445.1
Total MW output				850.1	366.4
Total MW Loss					483.7

AEMO (2016)

History of Blackouts

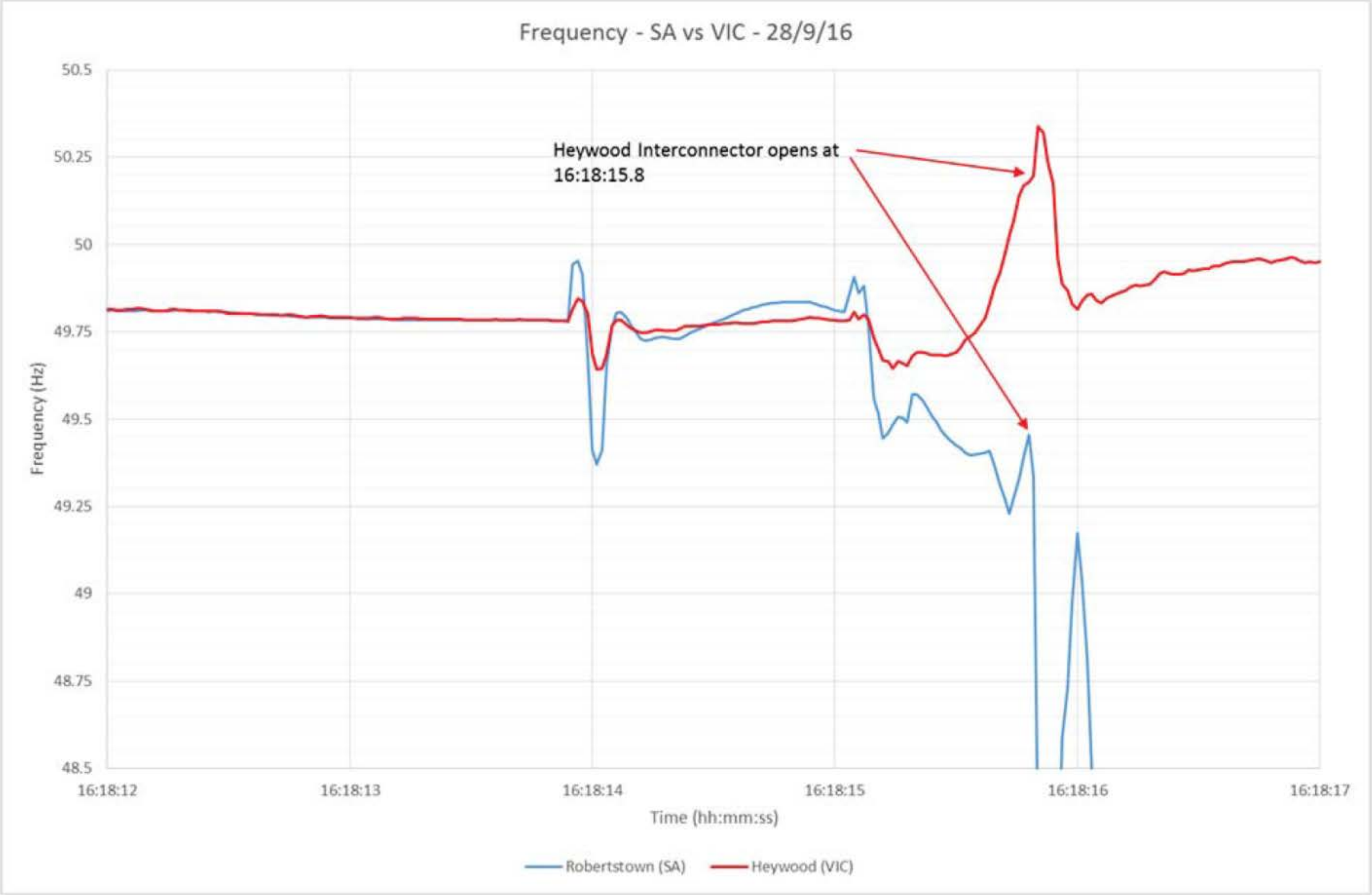
Voltage Profile During Event



AEMO (2016)

History of Blackouts

Frequency Profile During Event



AEMO (2016)

History of Blackouts

- Time for total customer restoration: 7 ½ hours
- System Restart Ancillary Service (SRAS) “black start” units did not operate as designed, even though they had been tested within the operating year
  - SRAS 1 could not start due to the switching sequence used. Corrective measures have been put in place and tested
  - SRAS 2 suffered a stator ground fault after 15 seconds of operation. This problem has been corrected
- AEMO power market prices spiked from $60 to $9000/MWhr*
  - AEMO suspended market operations during the event
  - The Australian government is currently reviewing the role of renewable vs. traditional forms of generation

*http://www.abc.net.au/news/2016-09-25/sa's-power-price-spike-sounds-national-electricity-alarm/7875970

History of Blackouts – Cyber Attack

Ukraine Blackout

- December 23rd 2015
- Three Ukrainian distribution companies were attacked
  - 225,000 customers outaged
- Seven 110-kV and twenty-three 35-kV substations were disconnected for 3 hours

History of Blackouts – Cyber Attack

- Initially thought to be solely the Black Energy 3 virus the attack included multiple elements to include:
  - Spear phishing of business networks
  - Telephone denial-of-service attack on the call center to delay/hamper restoration efforts
  - Use of a KillDisk program to delete targeted files and logs
  - Use of virtual private networks (VPNs) to enter networks
  - The use of keystroke loggers to perform credential theft and enter critical networks

NERC (2016)

History of Blackouts – Cyber Attack

Wired.com Article

The operator grabbed his mouse and tried desperately to seize control of the cursor, but it was unresponsive. Then as the cursor moved in the direction of another breaker, the machine suddenly logged him out of the control panel. Although he tried frantically to log back in, the attackers had changed his password preventing him from gaining re-entry. All he could do was stare helplessly at his screen while the ghosts in the machine clicked open one breaker after another, eventually taking about 30 substations offline. The attackers didn't stop there, however. They also struck two other power distribution centers at the same time, nearly doubling the number of substations taken offline and leaving more than 230,000 residents in the dark. And as if that weren't enough, they also disabled backup power supplies to two of the three distribution centers, leaving operators themselves stumbling in the dark.

https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/

History of Blackouts – Cyber Attack

Event Analysis

The NERC report identifies the following as the root cause of the event:

"The outages were caused by the use of the control systems and their software through direct interaction by the adversary. All other tools and technology, such as BlackEnergy 3 and KillDisk, were used to enable the attack or delay restoration efforts."

History of Blackouts – Cyber Attack

Clicking "Enable Content" gave the Black Energy 3 virus user access to energy networks

Black Energy 3 Macro

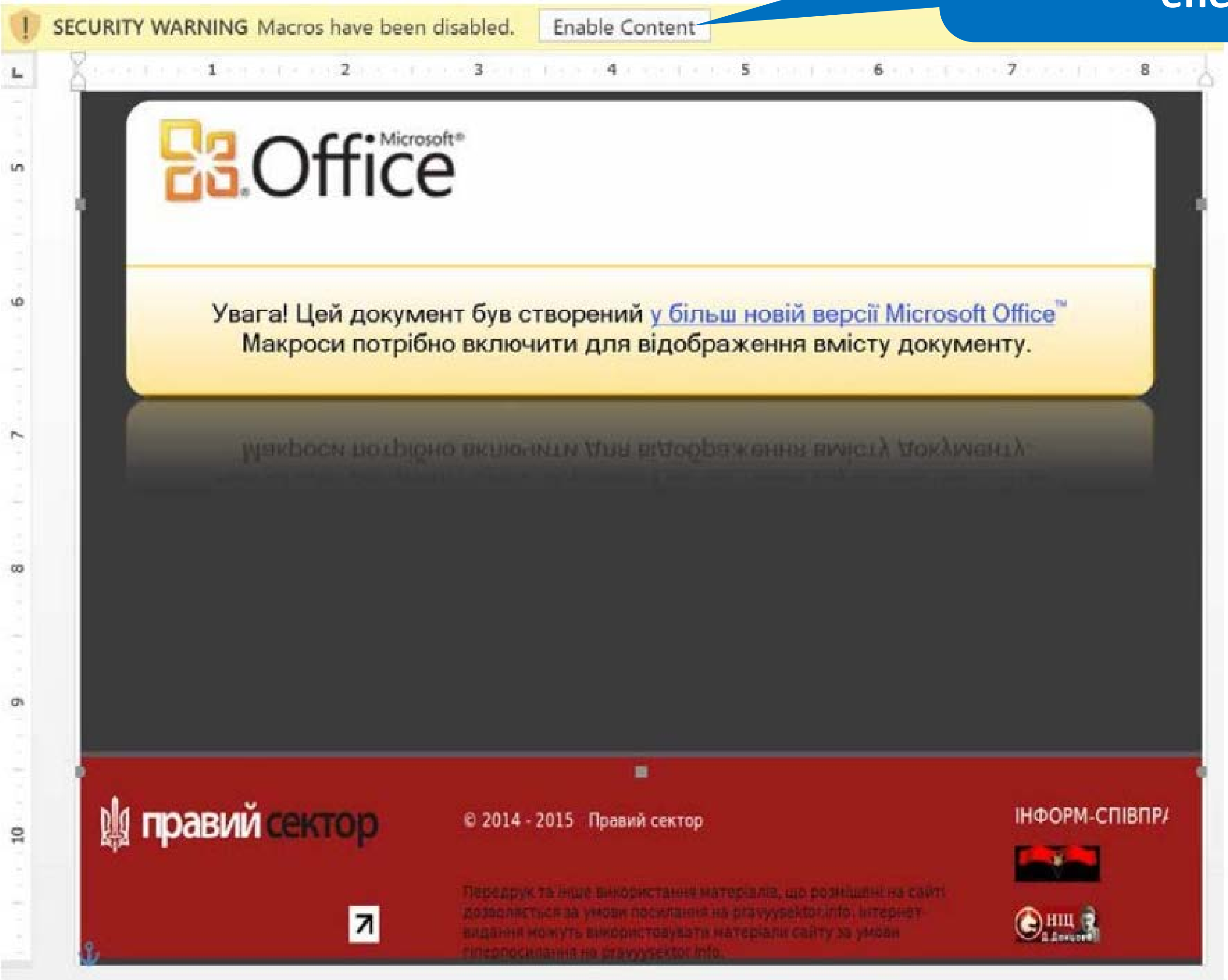


Figure 6: A Sample of a BlackEnergy 3 Infected Microsoft Office Document[27]

NERC (2016)

History of Blackouts

- Production
  - Loss of productivity
  - Loss of product or property
- Health
  - Food contamination
  - Medication problems
  - Anxiety
- Safety
  - Traffic accidents
  - Accidents due to visibility problems
  - Civil unrest

Types and Causes of Blackouts

Objectives

At the end of this module the Student will be able to:

- Identify the Types and Causes of Blackouts

- Describe the tasks associated with a system assessment of conditions immediately following the disturbance

- Describe the reporting requirements for a PJM initial status report

Types of Blackouts

- Localized
- Partial system
- Full system with/without outside help

Restoration strategy will be different for each type of outage!

Types of Blackouts

- Localized
  - Can range from one distribution circuit to the loss of an entire substation
  - Least severe of the types of blackouts
  - Most common of the types of blackouts
  - Generally affecting a small geographic area
  - Examples include:
    - Distribution feeder outage
    - Distribution bus outage
    - Substation outage

Types of Blackouts – Localized

- Most common causes
  - Faults on distribution system or in substation
  - Weather: lightning, rain, snow, ice, wind, heat, cold
  - Relay/SCADA malfunction
  - Human error: switching error
  - Vandalism
- Effect on other companies
  - If on distribution side, usually no effect on others
  - If on transmission side, others
    - May feel a system “bump”
    - May have oscillograph or DFR operation
    - May have over-trip of relays

Types of Blackouts – Localized

- Effect on PJM
  - May notice a rise in ACE if large amount of load was lost
  - May result in transmission problems if transmission was lost in the localized blackout
- Restoration method
  - Isolate faulted equipment
  - Restore load and remaining equipment through switching

Types of Blackouts

- Partial System
  - Spans more than one substation
  - May affect more than one Transmission Owner
  - Part of Transmission Owner’s transmission system is still energized
  - Affects a large geographic area

Types of Blackouts – Partial System

- Most common causes
  - Partial system voltage collapse
  - Cascading thermal overloads and trippings
  - Weather
  - Dynamic Instability
    - Multiple concurrent trippings of transmission, generation
    - Delayed fault clearing
- Effect on other companies
  - May also be partially blacked out
  - May experience voltage fluctuations (normally high)
  - May have transmission problems

Types of Blackouts – Partial System

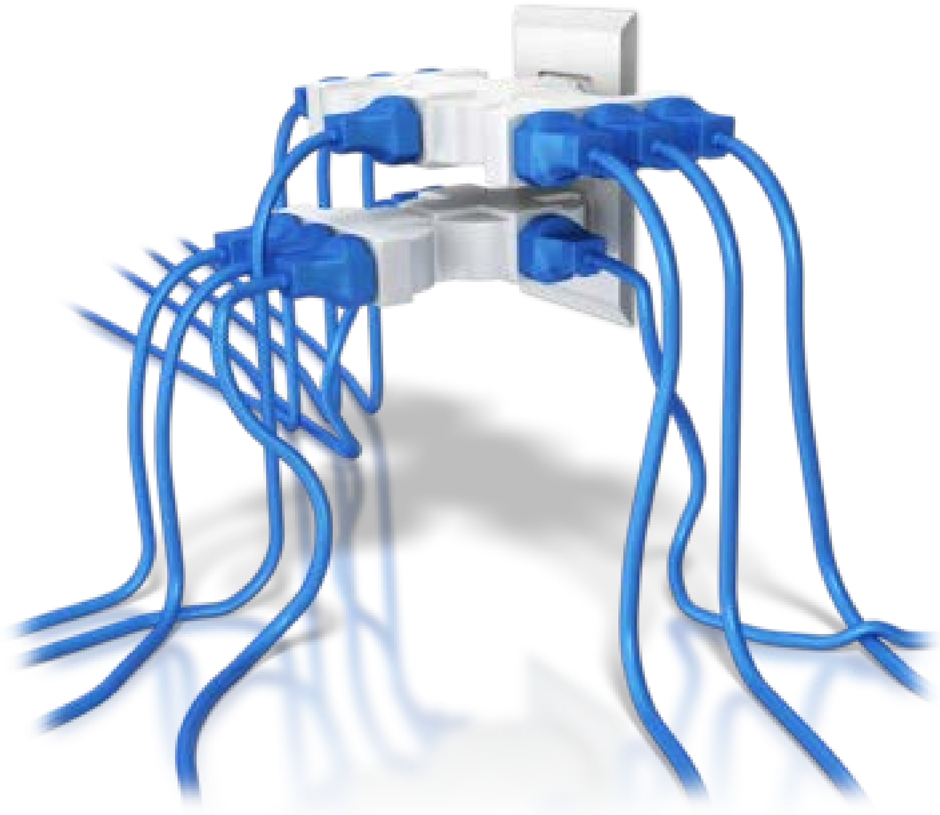
- Effect on PJM
  - Fluctuation in ACE (high or low)
  - Fluctuation in system voltages (normally high)
  - Fluctuation in frequency (high or low)
  - Transmission problems
  - Possible interchange adjustments
- Restoration method
  - Extent of outage will determine restoration method
    - Restore through switching from unaffected system
    - Start generation in blacked out area
      - Create islands
      - Synchronize when possible

Types of Blackouts – Full System

- One or more companies are totally blacked out
- Affects a very large geographic area and a large population of customers
- Each affected Transmission Owner may be in a different situation
  - Outside help available
  - No outside help available

Types of Blackouts – Full System

- Most common causes:
  - System voltage collapse
  - Frequency deviations
  - Dynamic instability
  - Cascading thermal outages
  - Severe weather event
    - Hurricane, Earthquake
  - Sabotage, acts of war



Types of Blackouts – Full System

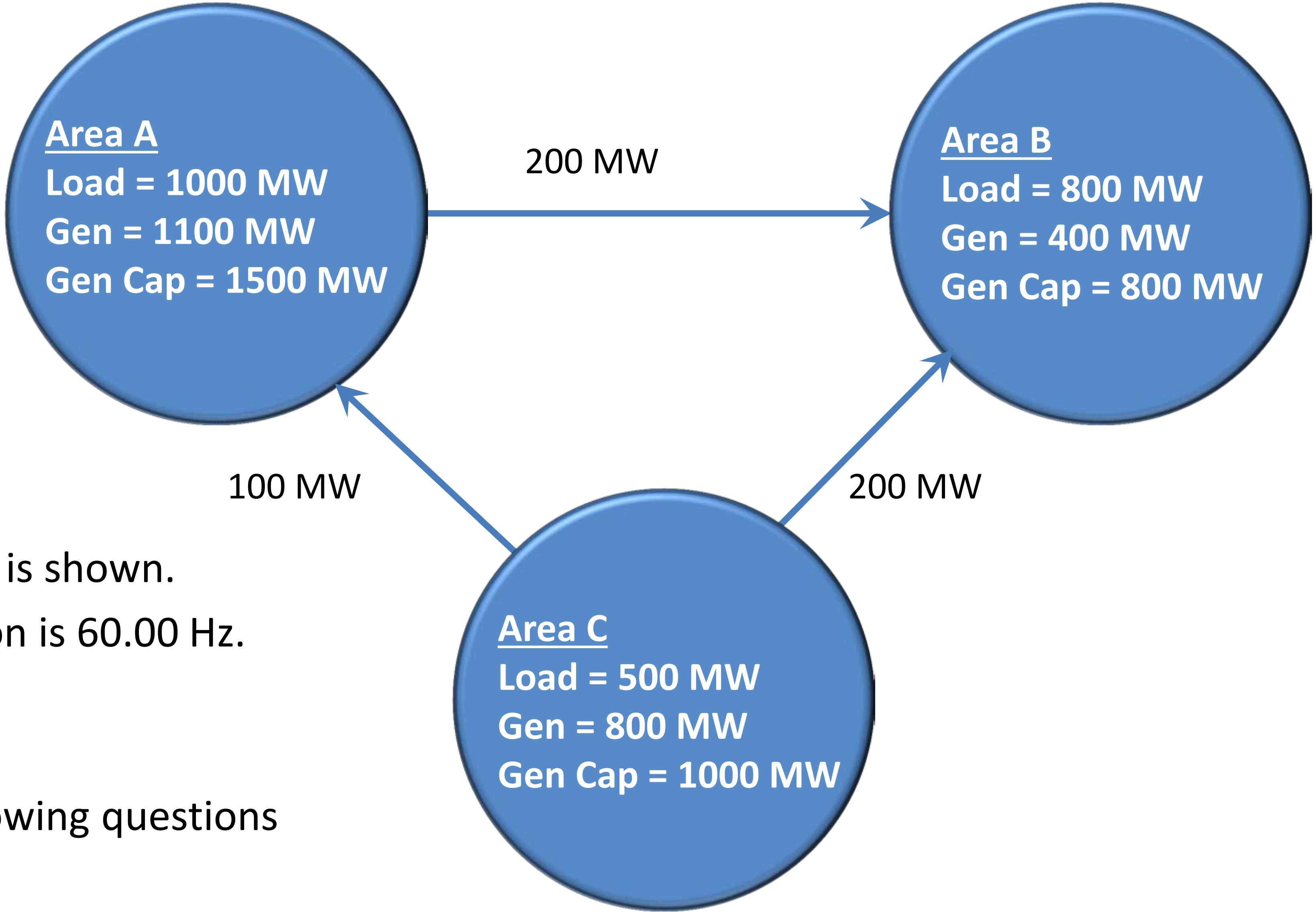
- Effect on other companies
  - May be blacked out or islanded
  - May be asked to provide assistance to neighbors
  - Will experience some operating problems
    - Power, voltage swings
- Effect on PJM
  - Similar to company effects
  - May need to coordinate multiple islands
  - Will need to adjust interchange schedules

Types of Blackouts – Full System

- Restoration Method
  - Dependent on if outside help is available
    - If it is, this opportunity should be investigated!
  - Dependent on individual company restoration philosophy
  - Details of the “Top down” and “Bottom up” methods will be presented later

System Disturbance Exercise

System Disturbance Exercise



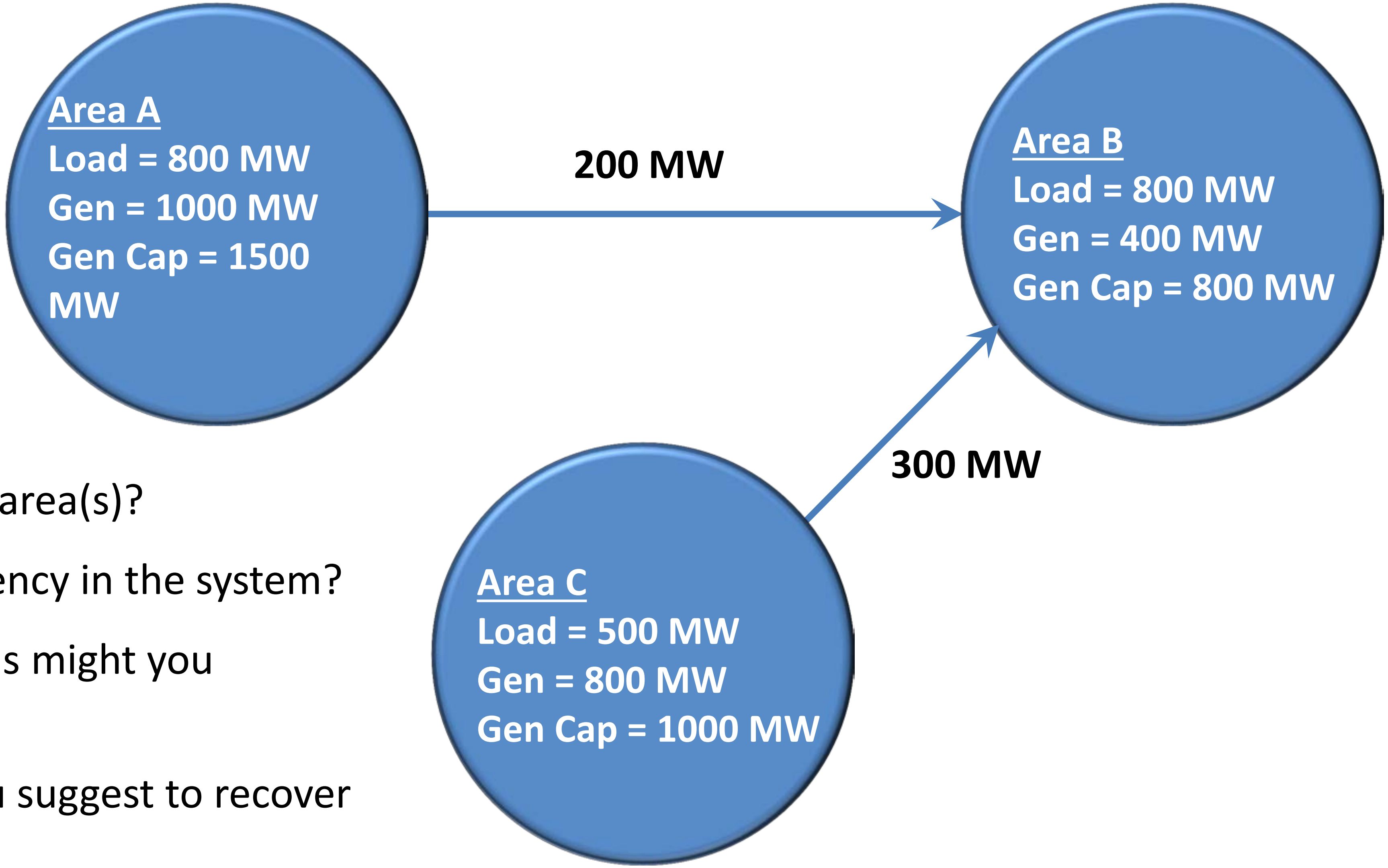
A Sample 3 Control Area system is shown.

Frequency of this interconnection is 60.00 Hz.
All tie flows are on schedule.

Actual tie flows are shown.

Use this data to answer the following questions

System Disturbance Exercise

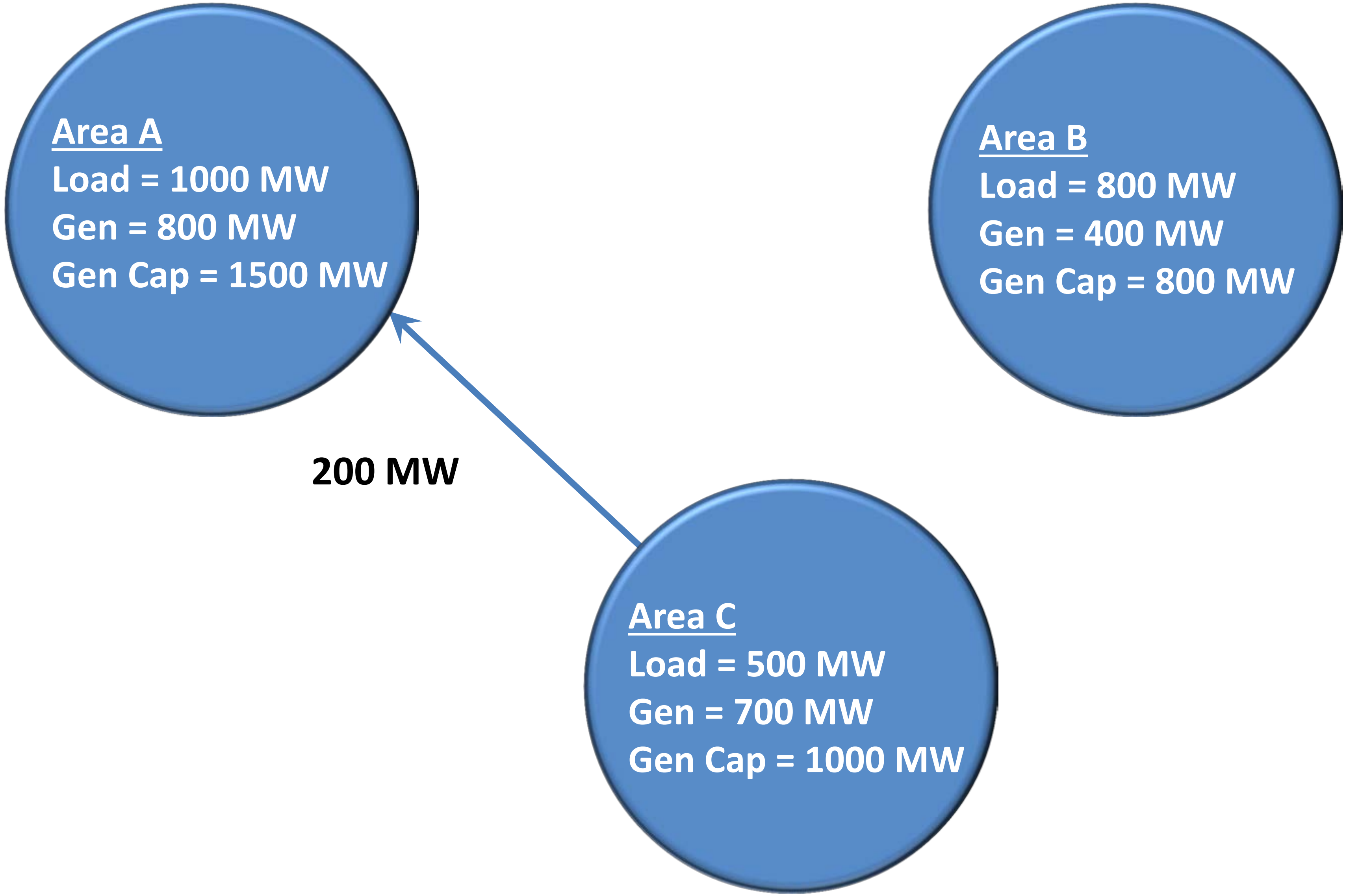


- What occurred and in what area(s)?
- What happens to the frequency in the system?
- What other system problems might you expect?
- What control actions do you suggest to recover the system?

System Disturbance Exercise

Cascading trippings on lines from A-B and B-C result in the conditions below:

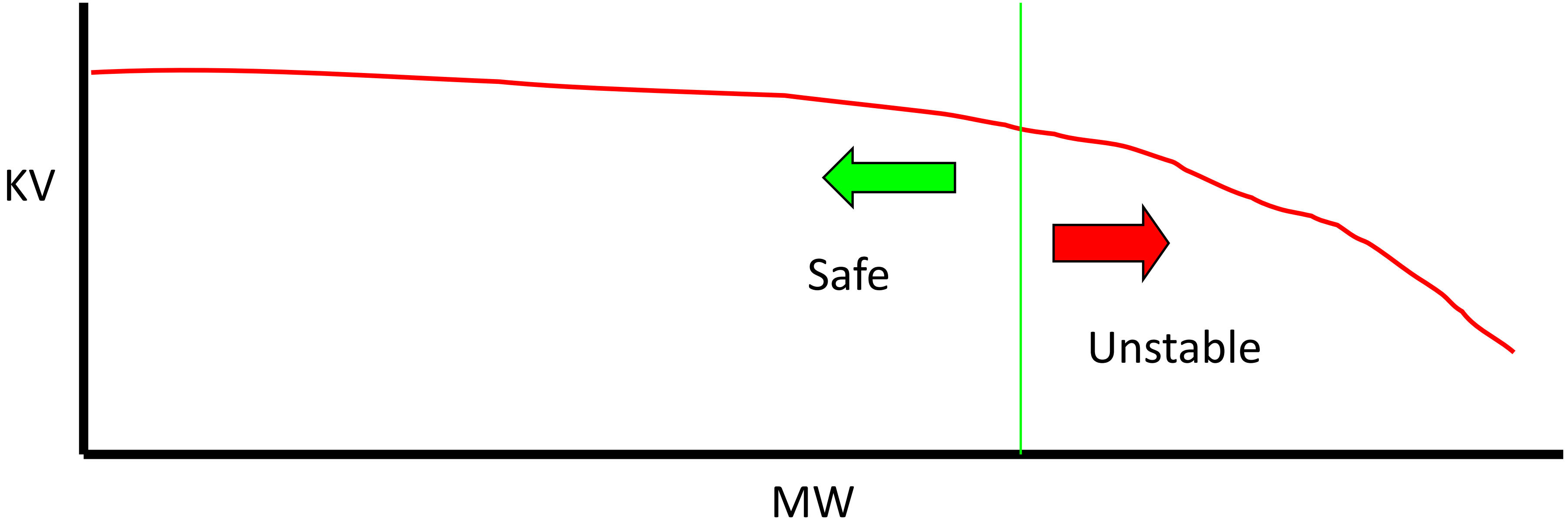
- What concerns do you have as an operator looking that the three systems?
- Area B blacks out due to low frequency. How would you suggest that they proceed in restoration?



Causes of Blackouts

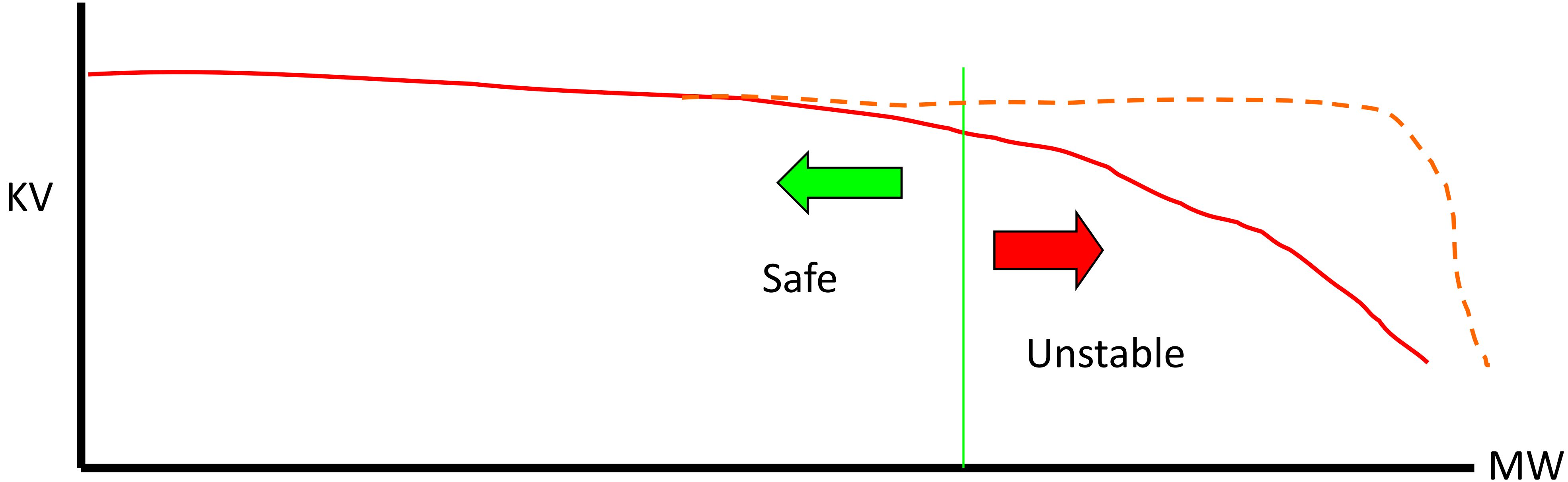
Causes of Blackouts

- Voltage Collapse
  - Deficit of MVAR Supply
  - Over the “knee” of the voltage curve
  - Results in system separations and generation trippings



Causes of Blackouts – Voltage Collapse

- Impossible to predict boundaries of separation
- May be detected by looking for areas of voltage decay
  - However, use of shunt capacitors can maintain near normal voltage up to the point where voltage support resources run out
  - Voltage drop curve starts to look like a right angle

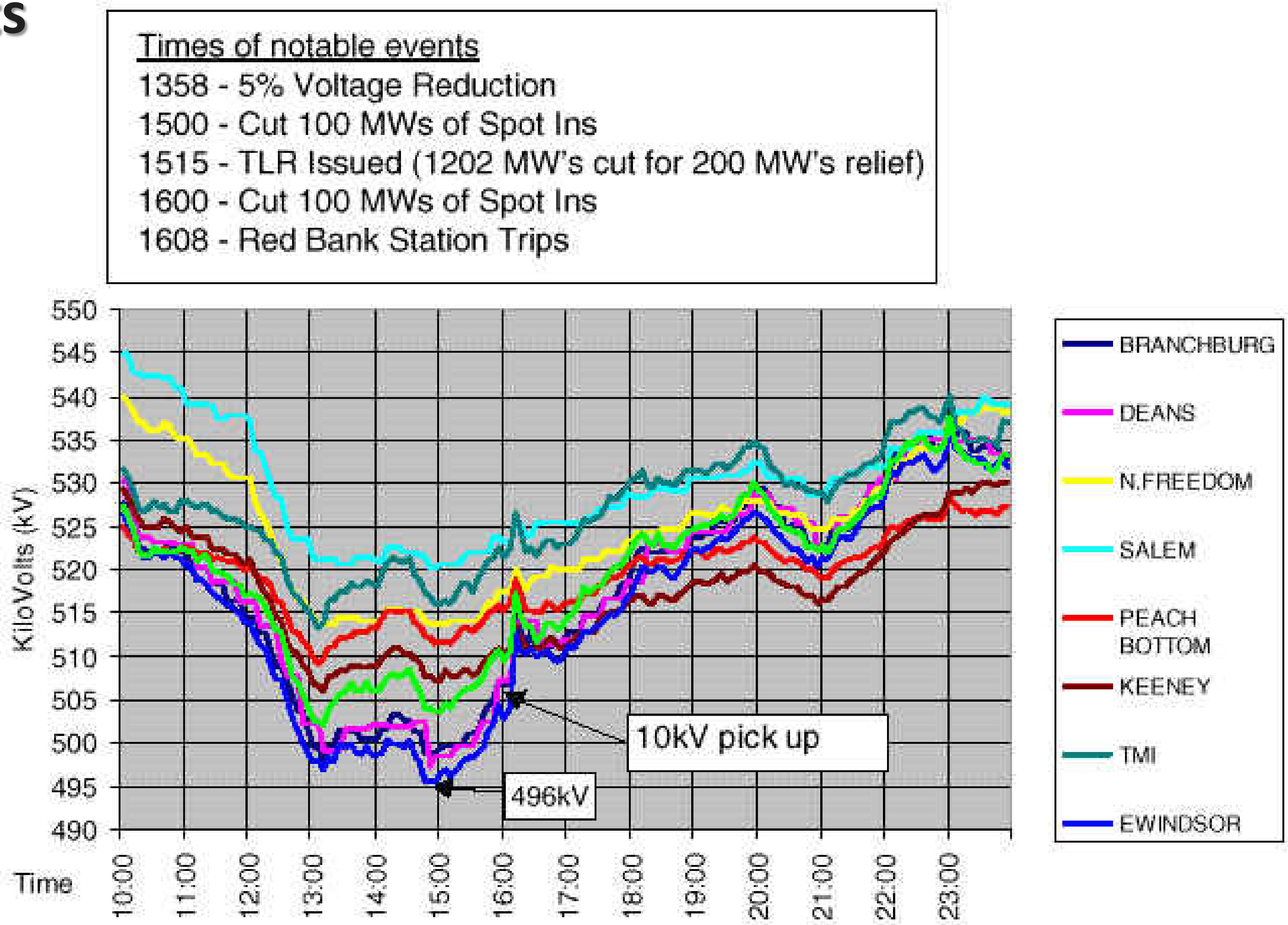


Causes of Blackouts – Voltage Collapse

- Rapidly decaying voltage (especially in high load periods) should be considered an emergency situation
- Time frame: Minutes to tens of minutes

Causes of Blackouts

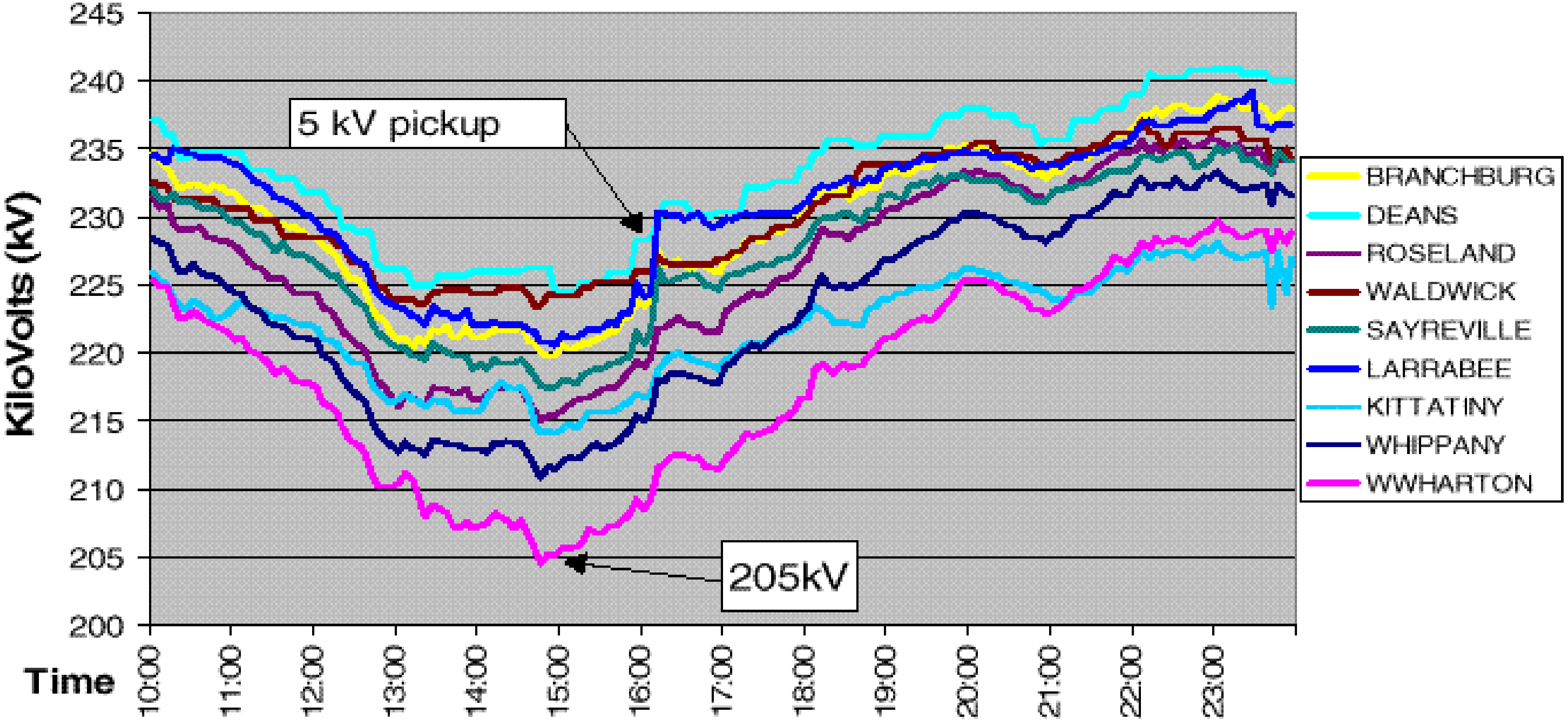
PJM Voltages
July 6, 1999



Causes of Blackouts

Times of notable events
1358 - 5% Voltage Reduction
1500 - Cut 100 MWs of Spot Ins
1515 - TLR Issued (1202 MW's cut for 200 MW's relief)
1600 - Cut 100 MWs of Spot Ins
1608 - Red Bank Station Trips

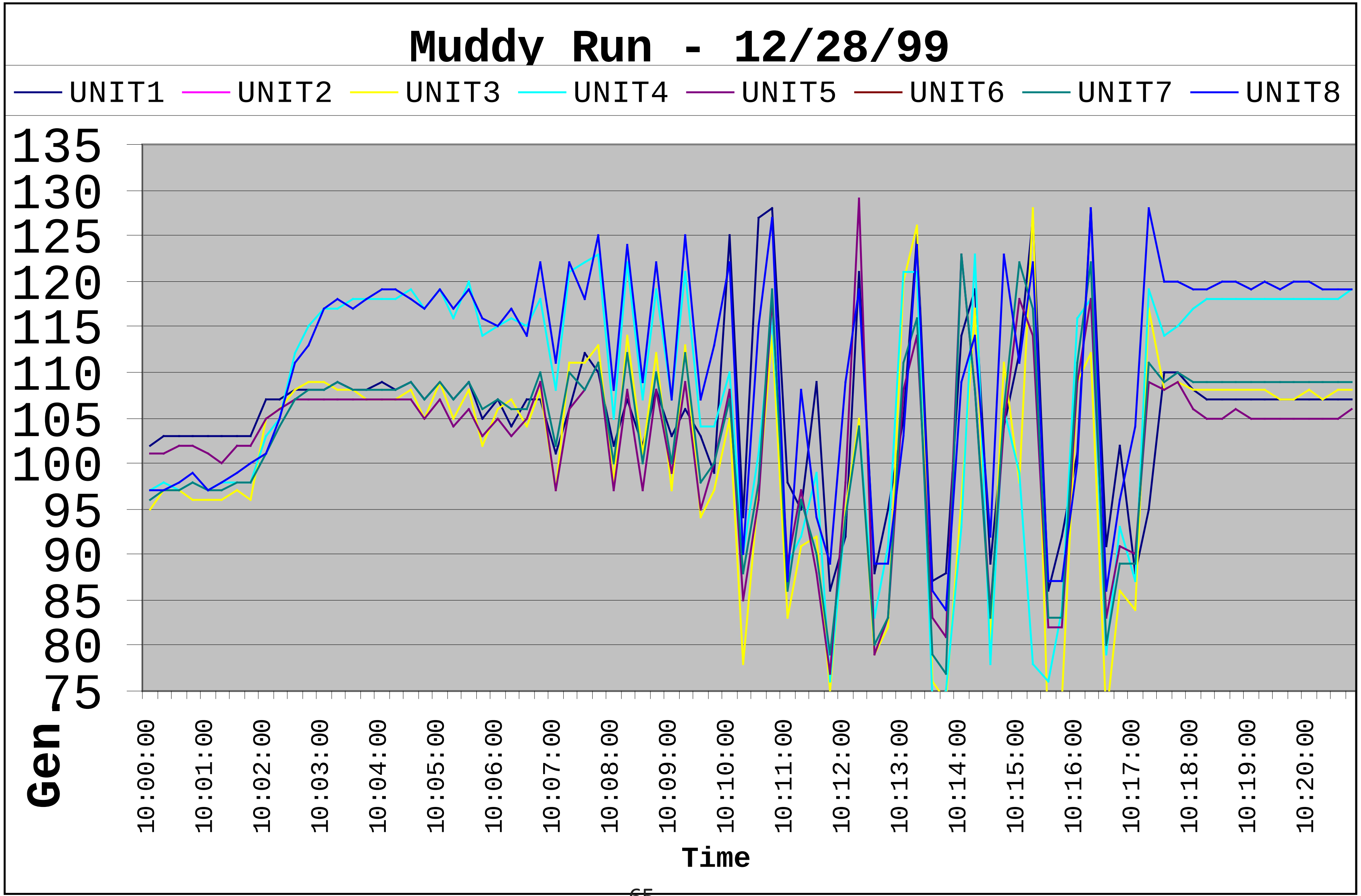
PJM Voltages
July 6, 1999



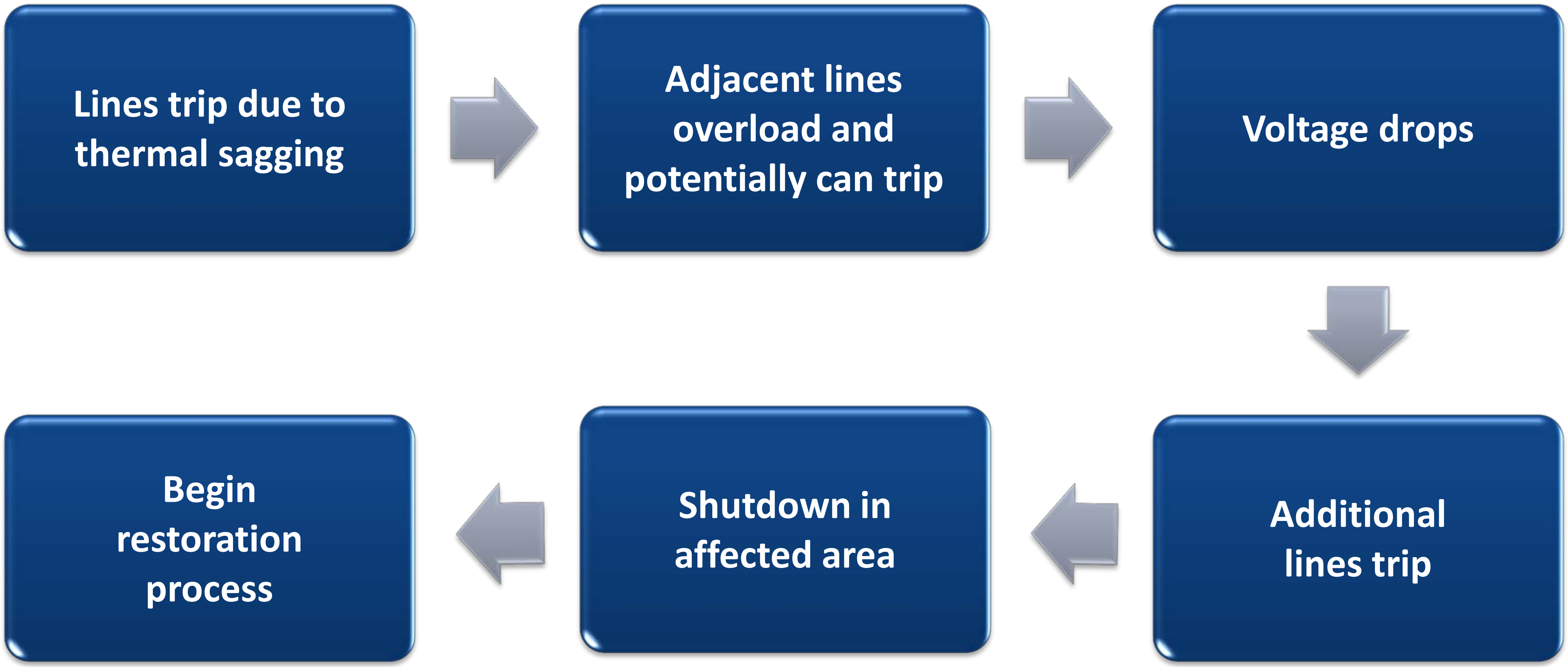
Causes of Blackouts

- Dynamic Instability
  - System does not damp out normal oscillations
  - Groups of generators “swing” against each other resulting in large oscillations in MW, MVAR
  - Could result in:
    - Generation trippings
    - Voltage collapse
    - Equipment damage
  - Time Frame: 5-15 seconds

Causes of Blackouts



Causes of Blackouts – Cascading Thermal Overloads



Causes of Blackouts – Cascading Thermal Overloads

- Transmission operating criteria is designed to prevent cascading overloads (first contingency)
  - No equipment can be operated such that the loss of a single facility causes any other facility to exceed it’s emergency thermal rating
- Could also be caused by severe weather
- Time frame: Minutes to several hours

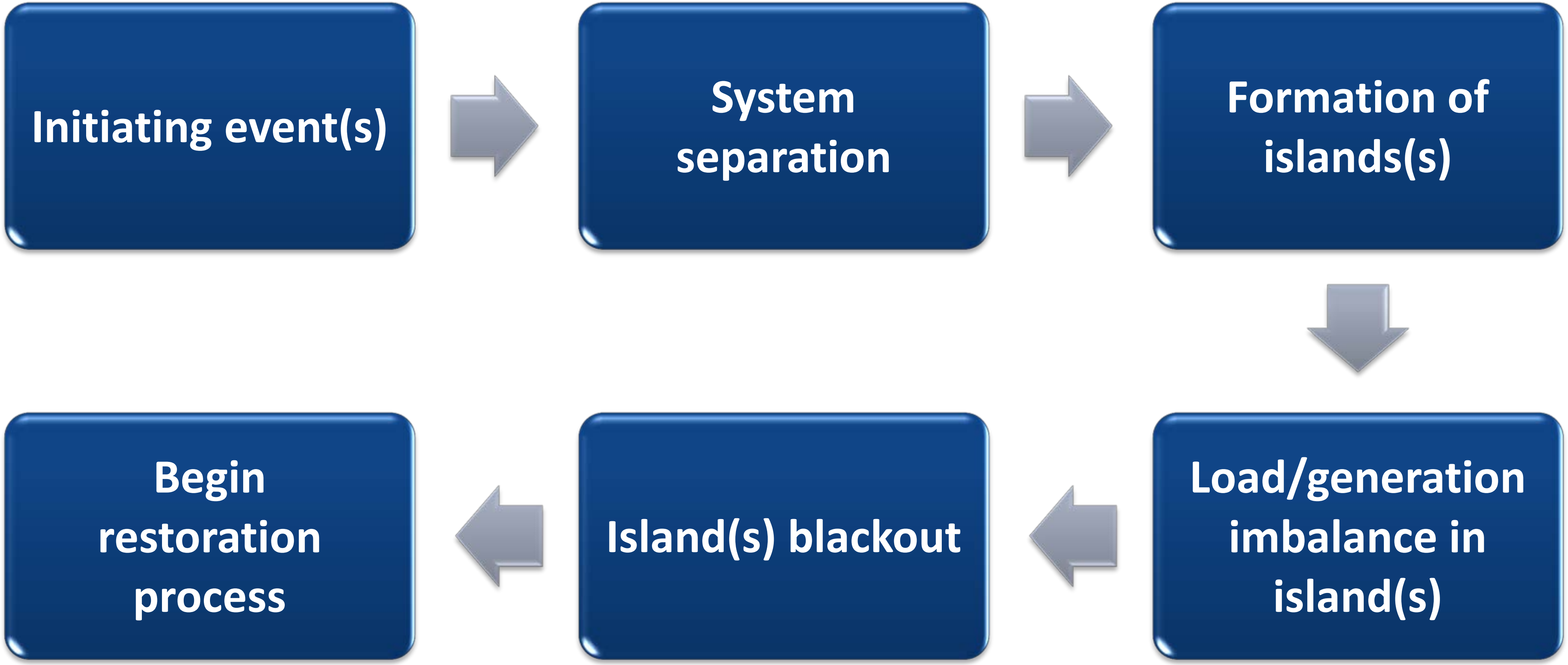
Causes of Blackouts

- Blackouts can (and have) occurred at all load levels, and during both peak and no-peak conditions

- Blackouts can happen during any type of weather

- No mater what the cause of the Blackout, your available system resources will determine your restoration strategy

Causes of Blackouts – Common Sequence of Events in Blackouts



Determining System Status

Objectives

- Describe methods of determining generator status
- Describe methods of determining transmission status
- Identify the PJM reporting requirements as a system restoration progresses:
  - Hourly Generation Reports
  - Periodic Transmission Reports

Initial Assessment

EMS Alarms

- First indication of a problem
- Barrage of alarms will appear
  - Some EMS systems have "smart" alarm processing to reduce the number of redundant alarms in a blackout situation
  - Don't delete the alarms. They will be helpful in system assessment and post-event analysis

Initial Assessment

Other EMS considerations

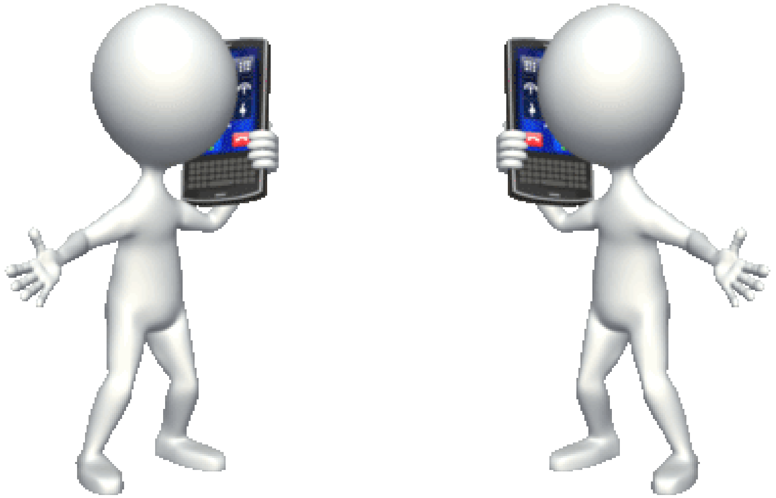
- State Estimators will not work in a complete or partial blackout situation
- If State Estimators is not working, Security Analysis functions will not work
- EMS performance may be slowed due to amount of alarm processing
- Telemetry and control may be spotty due to:
  - Communication failures
  - RTU failure or substation battery failure
- Data received may be of questionable integrity

Initial Assessment

- First step of the restoration process is a complete assessment of the system
- Communication capability must be checked
- EMS SCADA indications must be confirmed and must be accurate if the process is to be successful
- Immediate assessment of generation resources before any process is initiated
- Black Start process can be developed based on actual unit availability

Initial Assessment – Communications

- Functional communications are critical for the assessment of the extent of a blackout
- FIRST action following a blackout is to verify communication with:
  - PJM
  - Neighbors
  - Generating Stations
  - Substations
- Backup communication systems should also be verified since it may be necessary to utilize these systems



Initial Assessment – Communications

- Eliminate non-productive telephone communications
- Establish a communication center outside of dispatch center for communication with
  - Governmental agencies
  - Media
  - Customers
- Call for help
  - Extra dispatchers
  - Support personnel
  - Substation manpower

Determining Generator Status

Determine surviving on-line generation

Stabilize surviving on-line generation

Determine status of off-line generation

Determine preferred sequence of starting off-line generation

Prepare off-line generators for start-up

Restore auxiliary power to off-line generation

Determining Generator Status

- For generation that is still on-line determine:
  - Location
  - Damage
  - Stability
    - Frequency of island
    - Can load be added
  - Unloaded capacity
  - Connectivity to the rest of the system
    - Islanded
    - Part of Eastern Interconnection

Determining Generator Status

- For generation off-line determine:
  - Status prior to blackout (running, hot, on maintenance)
  - Blackstart capability of unit
  - Type of unit
    - Individual unit characteristics
  - Damage assessment
  - On-site source of power available or is off-site source (cranking power) required
  - Availability and location of cranking power

Determining Generator Status

- Sequence of restoration of off-line generation will be determined by:
  - Type of generator
    - Hydro: Can be started quickly without outside source
    - CT-small CTs: Can be started quickly (10 minutes); large CTs will take longer (up to 1 hour)
    - Drum-Type Steam: 1-20 away hours depending on status
    - Super Critical Steam: 4-20 away hours depending on status
    - Nuclear: At least 24 hours away (probably 48 hours or longer)
  - State of operation of unit prior to blackout
    - Hot units may be returned quicker than cold units
  - Unit availability

Determining Generator Status

- Auxiliary power should be restored to generation stations as soon as possible
- Short delays in restoring auxiliary power could result in long delays in restoring generation due to:
  - Congealed fuel oil
  - Sludge thickening in scrubbers (large demand of auxiliary power; as much as 30 MW)
  - Battery life expended
  - Bearing damage
  - Bowed shaft due to loss of turning gear

Determining Generator Status

- Prioritization of available cranking power to off-line generation depends on:
  - NRC requirements (more on this later!)
  - Individual restoration plan
  - Start-up time of unit
  - Availability of on-site auxiliary power
  - Distance of cranking power from generation
- Effective communication with generating stations is essential in this process!

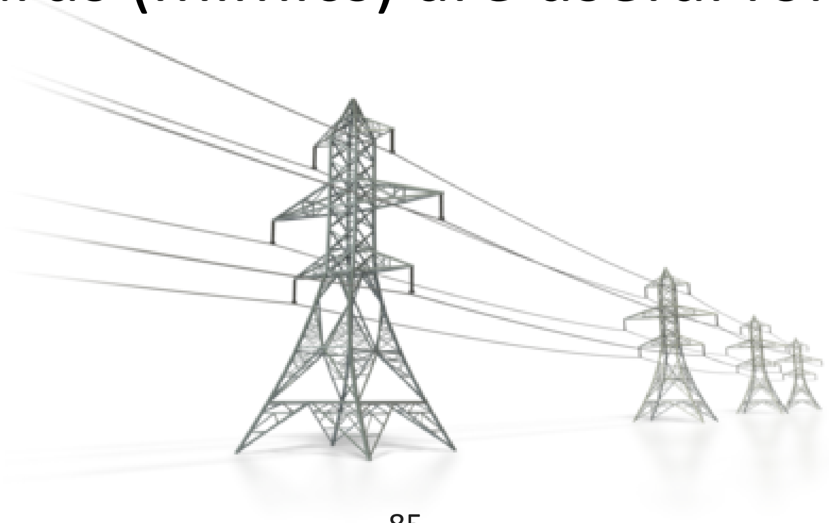
Determining Generator Status

- Generating plant operators take actions to perform a safe plant shutdown
- Steam plant operators implement start-up procedures immediately following a plant shutdown unless instructed otherwise by the dispatcher
- Governors must be in service to respond to large frequency deviations
- Frequency control is maintained between 59.75 Hz and 61.0 Hz
- Plant operators must take action on their own to control frequency outside the range of 59.5 Hz - 61.0 Hz

Determining Transmission Status

Determining Transmission Status

- Key EMS indications to determine extent of outage include:
  - Frequency measurements (if available)
  - Voltage measurements
  - CB indications
  - If possible, verify EMS indications with field personnel
- Transmission map boards (mimics) are useful for this analysis



Determining Transmission Status

- Open circuit breakers may indicate:
  - Permanent faults which may have initiated system shutdown
  - Out of Step conditions
    - As system collapses, power flow may swing through the impedance settings of line relays and trip the line. (Remember $R = \frac{V}{I}$)
    - These lines do not have a fault and are available for restoration
  - Temporary faults
    - Caused by cascading overloads and line sag
    - After shutdown, conductor has cooled and line is available for restoration

Determining Transmission Status

- <u>Open</u> circuit breakers may indicate:
  - Temporary faults in transformers, reactors and capacitors
    - Caused by equipment supplying neutral over-current
    - Generally this equipment’s relays lock out and must be manually reset
    - Equipment may be available for restoration, though may require additional testing to ensure no internal damage

Determining Transmission Status

- <u>Closed</u> circuit breaker may indicate:
  - De-energized line with no problem
  - Damaged equipment that was never cleared by relay action
  - Equipment that was damaged <u>after</u> the system shutdown
- Determination of initiating event of the system shutdown will go a long way in determining the status of transmission!

Determining Transmission Status

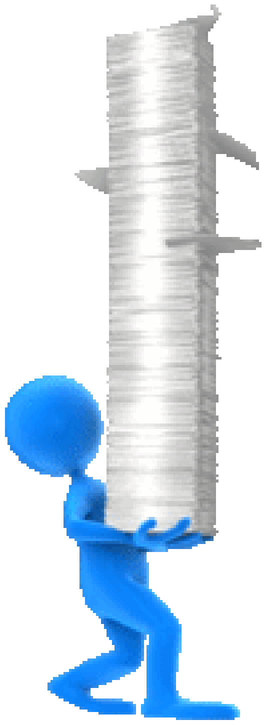
- Determining faulted transmission equipment may be difficult because circuit breaker position will **not** provide a reliable indication of faulted versus non-faulted equipment!
- Use the following methods to help determine the true faulted equipment:
  - Oscillograph and DFR operations and outputs
  - Substation inspections
  - Substation relay targets
- Faulted equipment should be isolated from the system

PJM Forms Required During a System Restoration

PJM Restoration Forms

- Information required for the following situations:
  - Initial Restoration Report
  - Generation Restoration Report
    - Submitted hourly
    - Which units are in service
    - Which units are expected in the near future
  - Transmission Restoration Report
    - Every 30 minutes

      OR
    - Every 10 lines restored



COMPANY INITIAL RESTORATION REPORT				
Reporting Company:			Date:	
Reporting Contact:			Time:	
Generation Lost (Capacity)			MW	
Generation Still Operating (Capacity)			MW	
Generation Still Operating (Energy)			MW	
# of Generators on Line				
# of Subsystems (Islands)				
Customers Load Lost			MW	
% of Customer Load Lost			%	
# of Customers Lost in (000)			THS.	
% of Customers Lost			%	
Total Restoration Expected to be Completed by, Date/Time				
Equipment Damage: ______________________________				
Comments (Any outside ties with systems external to PJM that may have survived, etc.): ______________________________				
Capacity – Rated Load Carrying Capability Energy - MW Loading on a Machine				

Exhibit 12: Company Initial Restoration Report

PJM Composite Initial Restoration Report

Date: / /

Time: HRs

Generation Data by transmission Zone

Company Report Time:								FE-E	FE-E	FE-E														PJM
Company:	RECO	PS	PE	AE	DPL	PL	UGI	JC	ME	PN	BC	PEP	SMECO	DOM	FE-S	DLCO	DAY	AEP	COM	Rochelle	FE-W	CPP	DUKE	EKPC	Total
Generation Lost (Capacity) MW																								
Generation still Operating Capacity (MW)																								
Generation still Operating Energy (MW)																								
# of Generators on Line																								
# of Subsystems																								

Load Data by Transmission Zone

Company Report Time:								FE-E	FE-E	FE-E														PJM
Company:	RECO	PS	PE	AE	DPL	PL	UGI	JC	ME	PN	BC	PEP	SMECO	DOM	FE-S	DLCO	DAY	AEP	COM	Rochelle	FE-W	CPP	DUKE	EKPC	Total
Customer Load Lost MW																								
% of Customer Load Lost																								
# of Customers Lost (000)																								
% of Customers Lost																								
Estimate for Total Restoration (Date/Time)																								

Exhibit 11: PJM Composite Initial Restoration Report

Company Hourly Restoration Report *

Date:		Time:	
Reporting Company:			
Transmission Zone:			
Company Contact:		Estimated Time to Complete Total Restoration: Date: Time:	
If no changes since last report submitted, report is not required			
GENERATION REPORT:	**MW**	**LOAD RESTORATION REPORT:**	**MW**
Generation: Capacity on Line		Total Customer Load Restored	
Generation: Energy on Line		# Of Customers Restored (000)	
# Of Generators on Line		% Customers Restored	
# Of Subsystems (Islands)		% Customers Restored Last Hour	
CAPACITY DUE IN:			
Generation in One Hour (1)			
Generation in Three Hours (3)			
Generation in six Hours (6)			

UNITS ON LINE SINCE LAST REPORT

Station	Unit	MW	Station	Unit	MW

UNITS EXPECTED DURING NEXT HOUR

Station	Unit	MW	Station	Unit	MW

Damage detected since last report / comments:

CRANKING POWER

From Company to Station	kV	Time	From Company to Station	kV	Time

* May be required more often. Information to be compiled by TO operators for units within their zone and submitted to PJM.

Exhibit 14: Company Hourly Restoration Report

Company Transmission Restoration Report

	Date:	Time:
	Reporting Company:	
	Company Contact:	
	** This report should be submitted every 10 lines restored or 30 minutes. During drills, reports may be e-mailed to RestorationForms@pjm.com. If no changes since the last report, no report is required.	
	EXAMPLE DATA	

ID	Facility Identification	Voltage Level	Date Restored	Time Restored	Energized since Last Report (?)	Expected in Next Hour (?)
5003	Keystone – Conemaugh		01/01/00	0800	X	
5004	Keystone – Juniata					X

ID	Facility Identification	Voltage Level	Date Restored	Time Restored	Energized since Last Report (?)	Expected in Next Hour (?)

Exhibit 15: Company Transmission Restoration Report

System Status Exercises

Generation Assessment

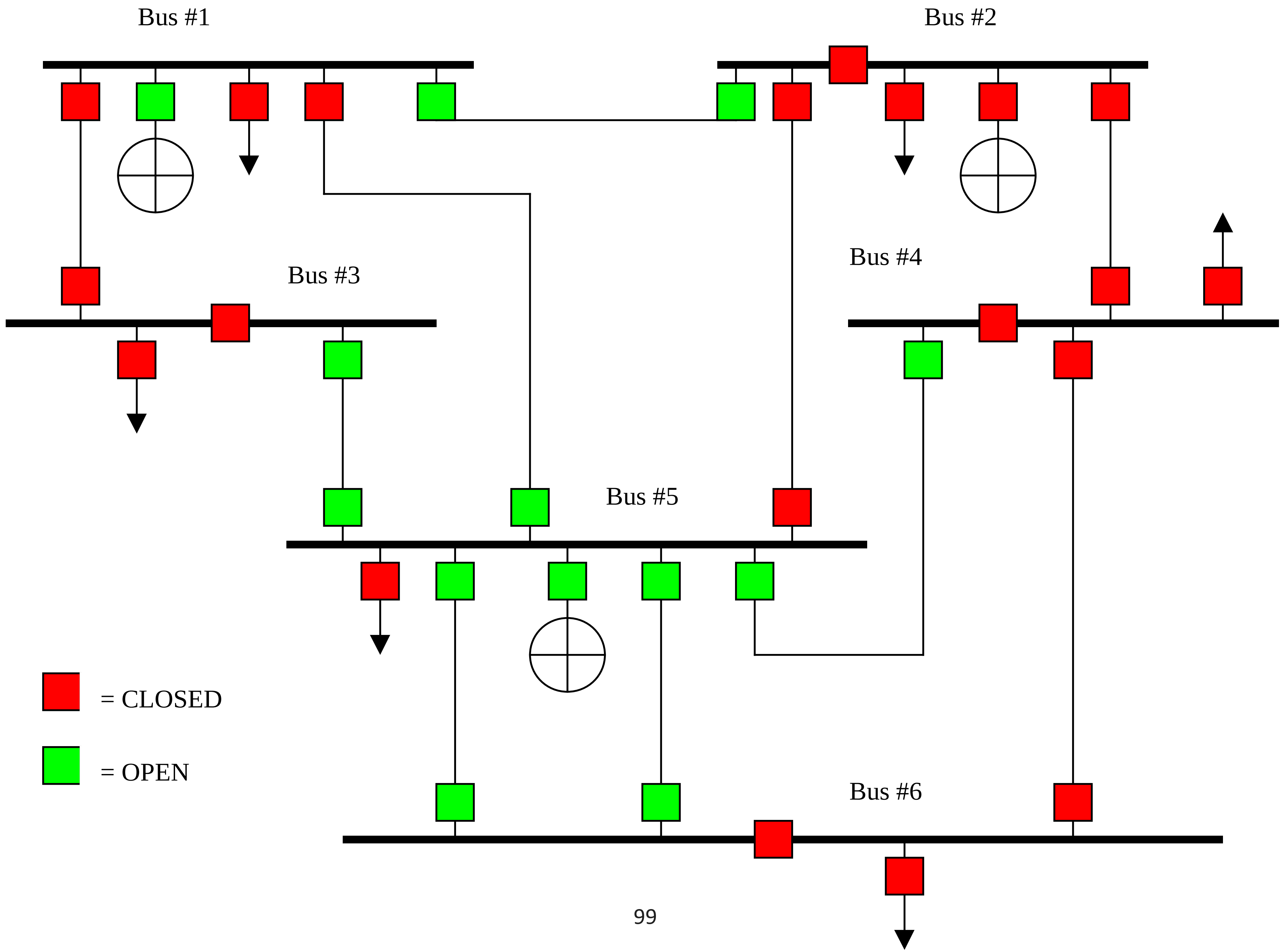
Your system has just suffered a complete blackout. You do a quick assessment of your generation resources and list them below. ***Rank the following units from 1-8*** in order of start-up priority (1 being highest priority, 8 being lowest priority)

	Small CT that had been off-line prior to blackout that is electrically close to a nuclear plant
	Drum-type steam unit that was on-line prior to the blackout
	Coal-fired steam unit that has been offline for 2 weeks
	Nuclear unit that is off-line for re-fueling outage for 6 more weeks
	Large CT that was off-line prior to the blackout
	Supercritical steam unit that was on-line prior to the blackout
	Run-of-river hydro unit with plenty of water available, electrically removed from other generation
	Nuclear unit that was on-line prior to the blackout

Generation Assessment

Your system has just suffered a complete blackout. You do a quick assessment of your generation resources and list them below. ***Rank the following units from 1-8*** in order of start-up priority (1 being highest priority, 8 being lowest priority)

1	Small CT that had been off-line prior to blackout that is electrically close to a nuclear plant
4	Drum-type steam unit that was on-line prior to the blackout
6	Coal-fired steam unit that has been offline for 2 weeks
8	Nuclear unit that is off-line for re-fueling outage for 6 more weeks
3	Large CT that was off-line prior to the blackout
5	Supercritical steam unit that was on-line prior to the blackout
2	Run-of-river hydro unit with plenty of water available, electrically removed from other generation
7	Nuclear unit that was on-line prior to the blackout


Bus #1
Bus #2
Bus #3
Bus #4
Bus #5
Bus #6
= CLOSED
= OPEN

Elements of a System Restoration

Objectives

At the end of this module the Student will be able to:

- Describe the various strategies of System Restoration including the “Bottom-up” approach, the “Top-down” approach, and a “Combination” of the two approaches
- Describe switching strategies used during system restoration and the advantages and disadvantages of each

Bottom-Up Approach

The "Bottom-Up" approach to restoration:

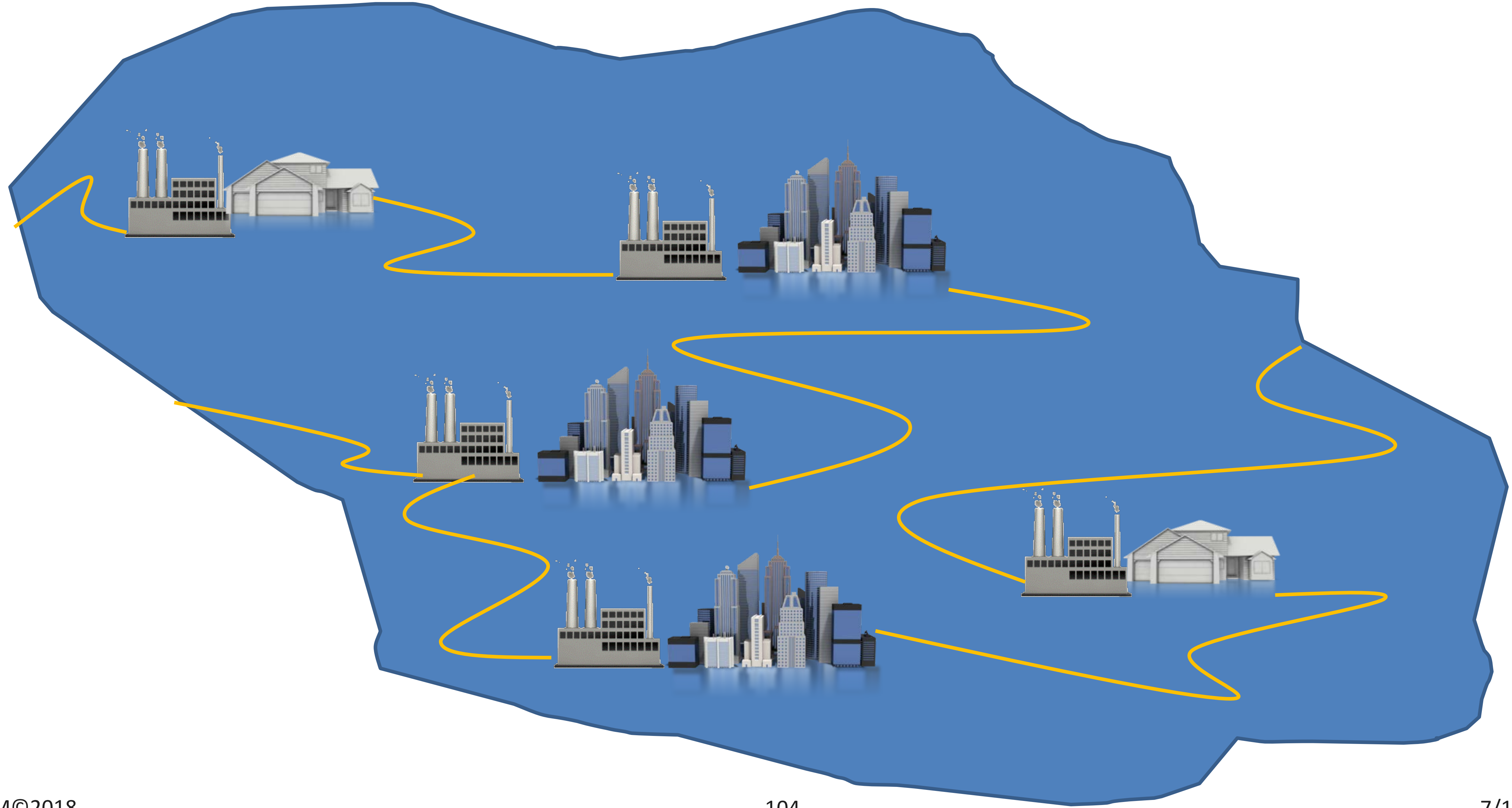
- Involves the formation of islands from black-start generation
- Has several variations that we will discuss in detail
- Is the only method of restoration available in a full system shutdown with no outside assistance available
- Should be the basis for company restoration plans

Bottom-Up Approach

Steps involved in the “Bottom-Up Approach”

1. Select units to black-start
2. Start and stabilize black-start units
3. Determine restoration transmission path
4. Begin expanding island(s) by restoring transmission and load
5. Synchronize island(s) when appropriate

Bottom-Up Approach: Multiple Island Method



Bottom-Up Approach

“Multiple Island” method of restoration

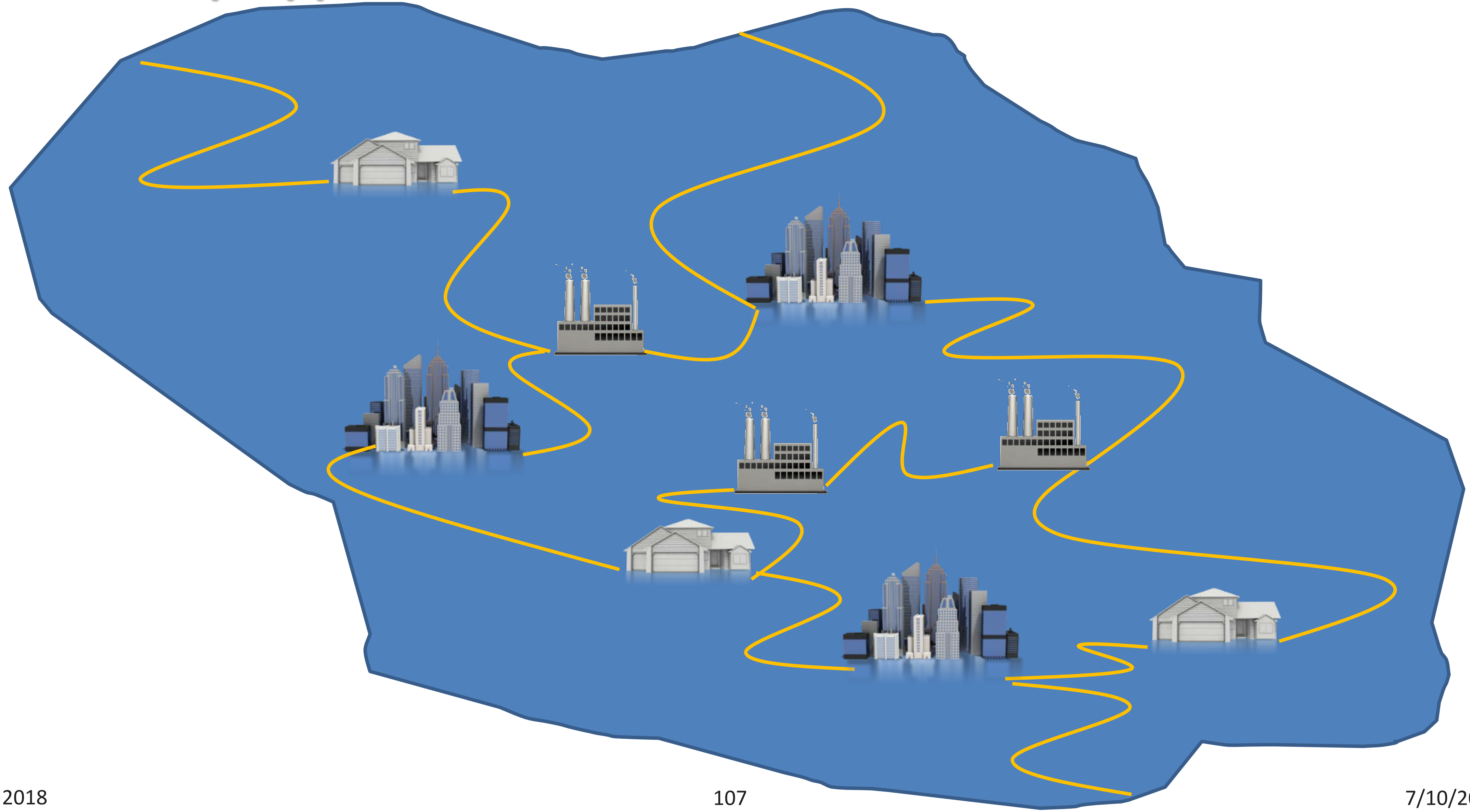
- Advantages
  - Multiple areas being restored in parallel
  - Faster restart of specific generation
  - If one island goes down, does not take down entire system
  - Allows for load pickup in critical geographic areas
  - High series reactance; high voltage drop

Bottom-Up Approach

"Multiple Island" method of restoration

- Disadvantages
  - More difficult to control and interconnect multiple islands
  - Less stability due to smaller size of islands
    - Frequency will have greater variation due to less inertia
  - Generation operators must control frequency within their island
  - Slower overall restoration time
  - Reduced available fault current (possible clearing problems)

Bottom-Up Approach: Core Island Method



Bottom-Up Approach

“Core Island” method of restoration

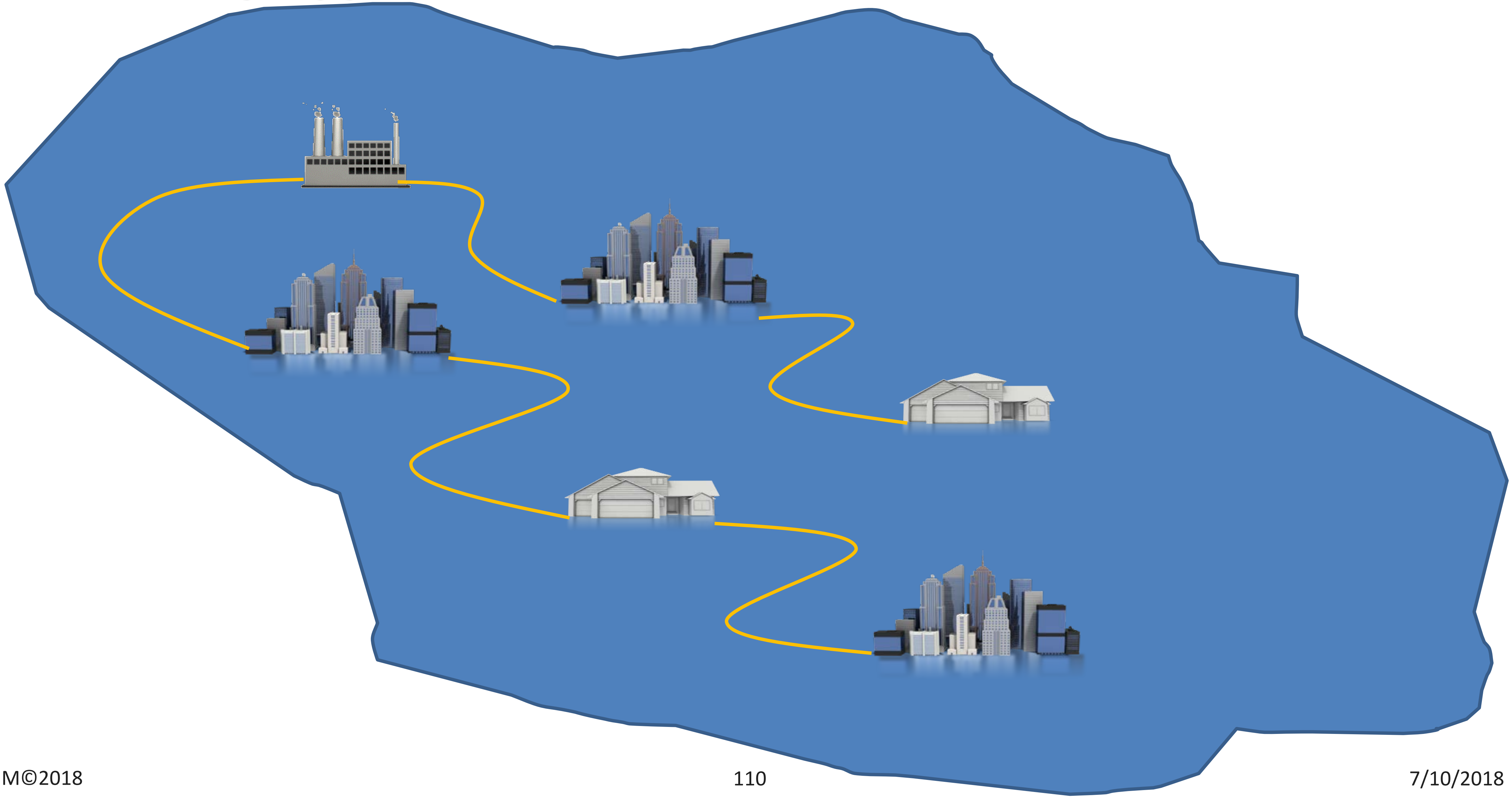
- Advantages
  - Forms larger, more stable island with more generation
  - More focused control and switching
  - As island grows, allows for larger block of load restoration
    - U/F relaying can be restored earlier - increased stability
  - Stable island more likely to be interconnected to neighboring systems.
  - Shorter overall restoration time
  - More available fault current, faster clearing times

Bottom-Up Approach

“Core Island” method of restoration

- Disadvantages
  - If core island blacks out, process must be restarted
  - Restoration of critical load at generating or substations may be delayed if not in core island
  - Stations further from core island may run out of station battery power before light and power can be restored

Bottom-Up Approach: Backbone Island Method



Bottom-Up Approach

“Backbone Island” method of restoration

- Advantages
  - Restores critical auxiliary power to generating stations and light and power to substations very quickly
  - Focused control and switching
  - Restores a backbone of the transmission system quickly potentially allowing for outside assistance quicker

Bottom-Up Approach

“Backbone Island” method of restoration

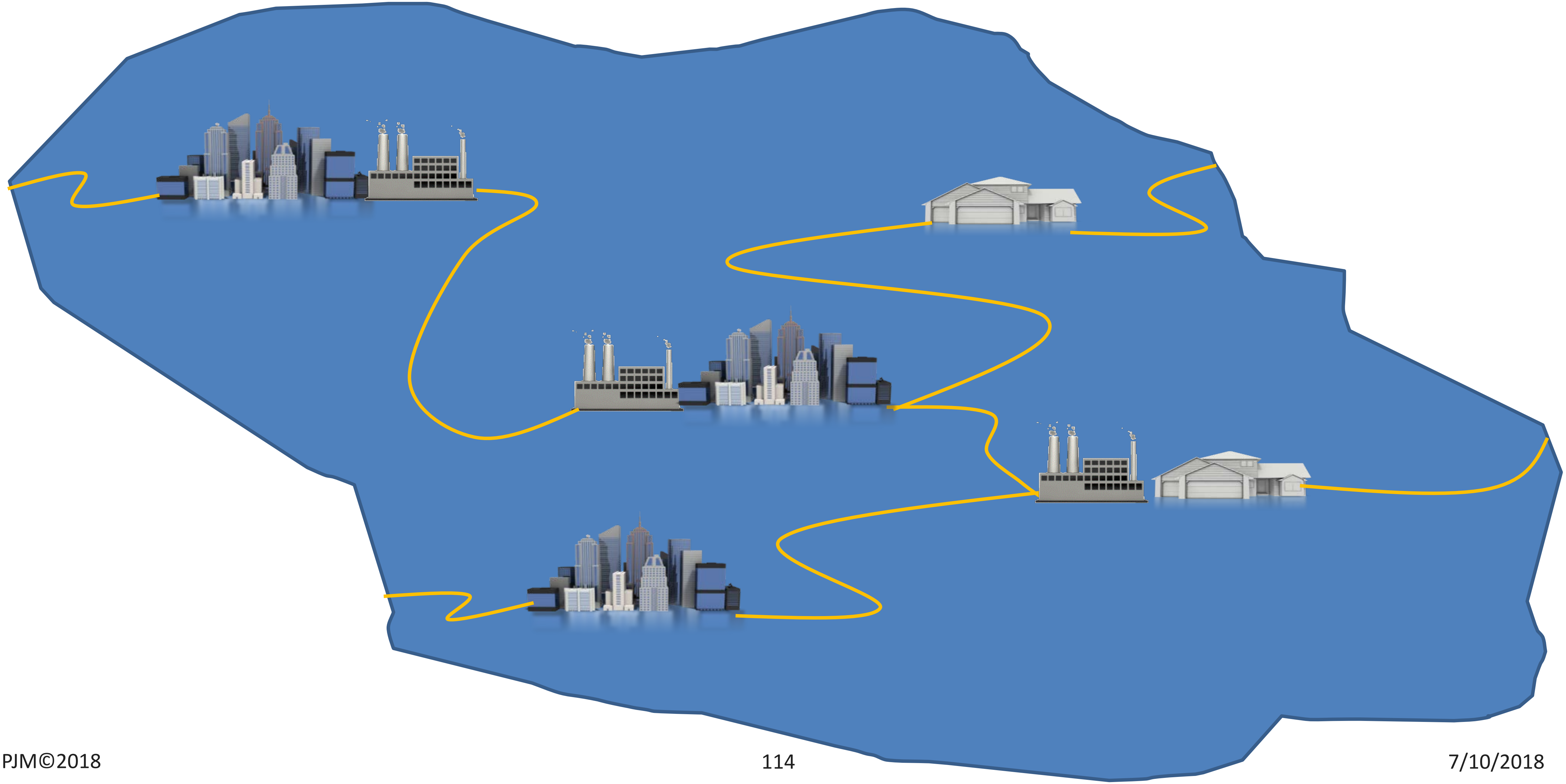
- Disadvantages
  - May experience high voltage due to excess line charging
    - Voltage control is difficult
  - Island may be unstable due to limited on-line generation and relatively longer transmission with less networking
  - May initially delay restoration of critical customer load

Top-Down Approach

Steps involved in the "Top-Down Approach"

1. Restore backbone transmission system, usually from outside assistance
2. Restore critical generating station and substation load from transmission system
3. Bring on more generation
4. Restore underlying transmission system
5. Continue restoring load

Top-Down Approach



Top-Down Approach

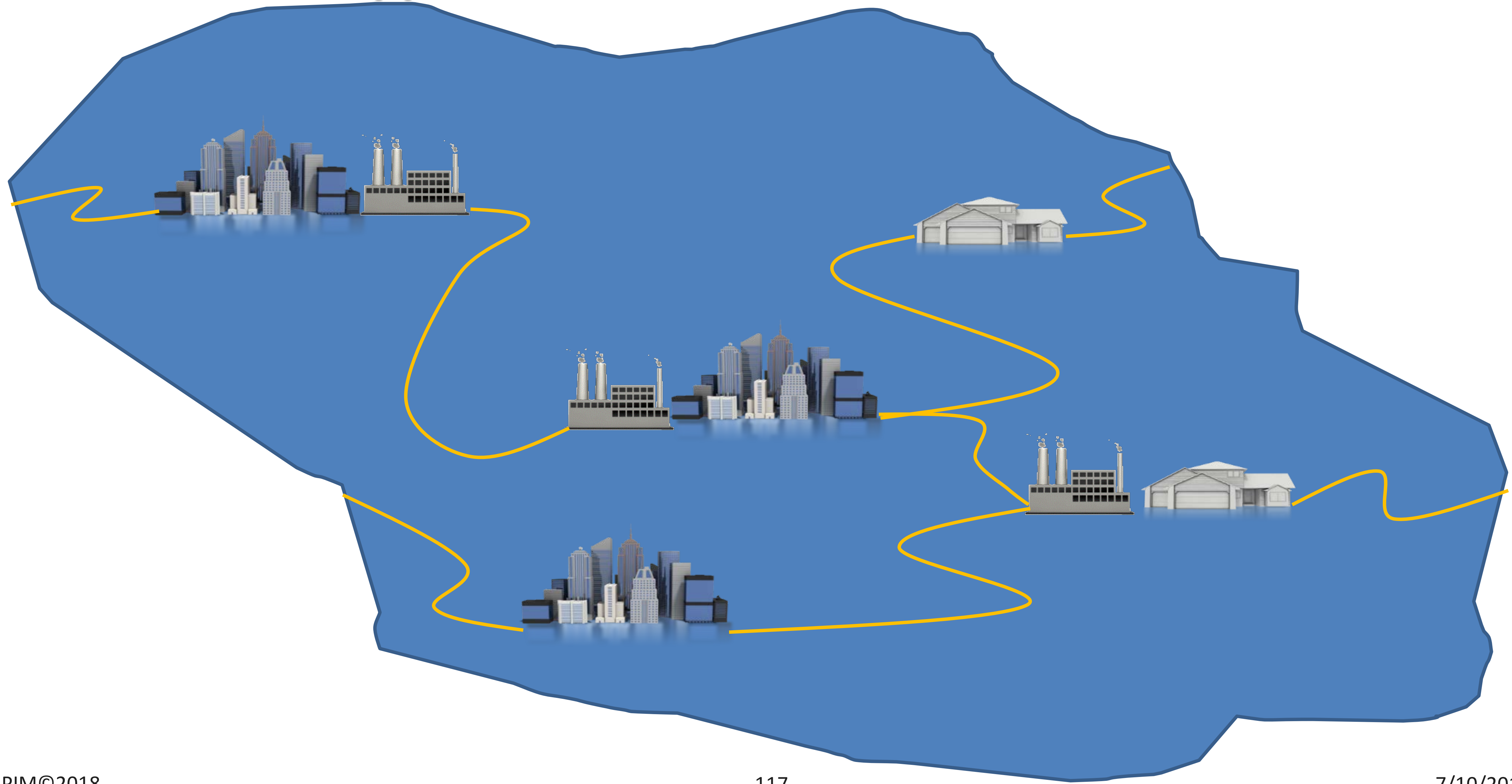
- "Top-Down" method of restoration
  - Advantages
    - Restores critical auxiliary power to generating stations and light and power to substations very quickly
    - Can restore several areas of the system at the same time
    - System should be stable since connected to Eastern Interconnection
    - No synchronization required due to one island
  - Disadvantages
    - May experience high voltage due to excess line charging
    - Reliant on neighbors ability to supply power
    - May experience transmission constraints

Combination Approach

Combines the "Bottom-up" and "Top-down" approach

- The Combination approach includes:
  1. Restoring transmission from an outside source at the same time as building "islands" of generation
  2. Interconnecting "islands" with each other or outside source when able

Combination Approach



Combination Approach

"Combination" method of Restoration

- Advantages
  - Quickest way to restore critical auxiliary power to generating stations and light and power to substations
  - Can restore several areas of the system at the same time
  - Load connected to outside world is very stable
- Disadvantages
  - May experience high voltage due to excess line charging
  - Reliant on neighbors ability to supply power
  - Requires synchronization of multiple islands
  - Control of multiple islands and frequencies becomes complex

Selection of a Restoration Method

- Restoration method chosen depends on:
  - Extent of blackout
  - Availability of outside assistance
  - Availability of internal black-start generation
- Company restoration plans based on worst case scenario and approved by PJM

When deviating from approved restoration plan, communication must occur between the TO and PJM

Choosing a Restoration Method Exercises

Choosing a Restoration Method – Exercises

For the following scenarios, identify which method of restoration would be most appropriate. The choices are Bottom-up Multiple Island, Bottom-up Core Island, Bottom-up Backbone, Top-down and Combination method. Give a brief description of your reasoning for selecting the method you did

1) Your system has suffered a disturbance involving multiple transmission trippings. The disturbance has left several blacked out “pockets” or “holes” in your system. Each pocket contains a large steam generation unit but no CTs or hydro units. Though your system suffered a loss of load during this event, the portion of the system remaining is very stable

Top-down method. Rebuild the system from stable outside system. You have no black-start capability in the blacked out area

Choosing a Restoration Method – Exercises

2) Your system has suffered a complete blackout. You receive information that your neighboring systems are also blacked out. Your system consists of several large load centers with black-start capable CTs available in each load center. These load centers are connected to each other by very long transmission lines

Bottom-up multiple island. You can restore multiple areas at one time. Stability and voltage control in trying to connect areas with long transmission lines using core island method would be difficult

Choosing a Restoration Method – Exercises

3) Your system has suffered a complete blackout. You receive information that your neighboring systems are unaffected and still connected to the Eastern Interconnection. You have a very large system with a critical load center including a nuclear plant in the electrical center of your system. You have black-start capable generation strategically placed throughout your system

Combination method. Use your black-start generation to restore critical load center. Work in from outside areas to restore load and eventually synch with critical load center

4) Your system has suffered a complete blackout. You receive information that your neighboring systems are also blacked out. Your system consists of a large load center in the electrical center of the system with small pockets of rural load covering a large physical area. Most of your generating resources are located in the large load center

Bottom-up, Core Island method. Begin restoring core island in the load center and work out to system edges as appropriate

Switching Strategies

Switching Strategies – Restoration Switching Strategies

"All-Open" Approach

- All circuit breakers at blacked-out substations are opened prior to restoration process

Switching Strategies – Restoration Switching Strategies

"Controlled Operation" Approach

- Only those circuit breakers necessary to allow system restoration to proceed are opened

Switching Strategies – "All Open" Approach

- Advantages
  - Simpler and safer configuration to re-energize
    - System collapse due to inadvertent load pickup less likely
    - Only breakers involved in restoration process need to be closed
- Disadvantages
  - Longer restoration time
  - More stored energy required for greater number of breaker operations
    - Compressed air or gas, springs, station battery
    - Breakers should be capable of one open-close-open operation without ac station service

Switching Strategies – "Controlled Operation" Approach

- Advantages
  - Less stored energy requirements
    - Breakers not involved in the initial sectionalization and restoration remain closed
    - Some breaker operations may not be needed until after station service is re-established
- Disadvantages
  - Dispatcher must be continually aware of boundary between restored and de-energized systems
    - Switching process becomes more complex
    - Possibility of system shutdown due to inadvertent load pickup is increased

Switching Strategies – System Sectionalizing

- Switching to disconnect load and capacitors from system prior to energization to prevent:
  - Large blocks of load pickup for frequency control
  - High voltage and generator under excitation
- May want to switch shunt reactors into service to prevent high voltage during transmission restoration
- Review transformer tap positions prior to energization especially if under automatic control
- Generator voltage regulators should be in service
- Protective relaying on all equipment should be in service

Restoring Power to Critical Facilities

Objectives

At the end of this module the Student will be able to:

- Define types of Cranking Paths
- Identify what PJM refers to as Critical Loads and Priority Loads
- Discuss some concerns related to the restoration of offsite power to Nuclear stations during the restoration process
- Discuss some concerns related to the restoration of power to pipe-type cable installations during a restoration process
- Discuss the sequence of restoring power to critical customer loads during a restoration process

Cranking Paths

- Shutdown generation units that do not have black start capability require start-up cranking power from an off-site source
- To accommodate this, transmission and distribution lines and buses must be established and these Cranking Paths to non-black start unit must be identified in each TO's system restoration plan (SRP)
  - This includes any arrangements with other TOs or system to provide start-up assistance not available within the company's area

Cranking Paths

The following types of Cranking Paths are defined:

- **Cranking Path** – transmission path from a Black Start unit to another generator to facilitate startup of that generator to aid in the restoration process
- **Critical Restoration Path (Nuclear)** – transmission path from a Black Start unit (or other source) that provides offsite power to a nuclear plant's auxiliary equipment to allow the nuclear plant to maintain safe shutdown
- **Critical Restoration Path (Load)** – transmission path from a Black Start unit (or other source) to restore load that is identified as critical load
- **Non-Critical Restoration Path** – transmission path from a Black Start unit (or other source) to restore non-critical loads or facilities as identified in the System Restoration plan

Critical Load Restoration

- Critical loads are restored by critical black start generation
- Minimum Critical Black Start Requirements for each transmission zone consists of:
  - Cranking power load to units with a "hot" start-up time of 4 hours or less
  - Off-site nuclear station light and power
    - Including units off-line prior to disturbance to maintain a safe shutdown
    - One feed into each facility
  - Critical gas infrastructure
    - Key in quick restoration of critical steam units

Load Restoration

- Priority load provided by black start or generation
  - Nuclear Station Auxiliary Power
  - Cranking power to generation with a start time greater than 4 hours
  - Power to electric infrastructure
    - Light and power to substations
    - Pumping plants for underground cable systems
  - Communication equipment
  - Command and control facilities
  - Under frequency load shed circuits

Load Restoration

- Nuclear Station Auxiliary Power (Priority load)
  - Emergency on-site generators provide for safe shutdown
  - NRC mandates restoration of at least two <u>independent</u> off-site power sources as a priority for a station start-up
    - Off site power should be provided consistent with the timelines identified in the TO restoration plan or NPIR agreements
  - Adequate voltages must be observed on the system
  - System frequency must be stable
  - Upon the availability of off-site power to non-safeguard busses a restart of the unit is possible, assuming no damage

Load Restoration

Substation light and power required for:

- SF6 CBs heaters and compressor
  - Cold weather reduces time window for normal breaker conditions to as short as 30 minutes
  - Operation may be blocked by interlocks preventing operation with low pressure or temperature
  - May be manually operated but usually requires the breaker to be de-energized
- Battery chargers
  - Should have 8 hours of battery life
  - Battery capacity should handle all normal DC loads, largest credible substation event, and one open-close-open operation on each substation device

Load Restoration

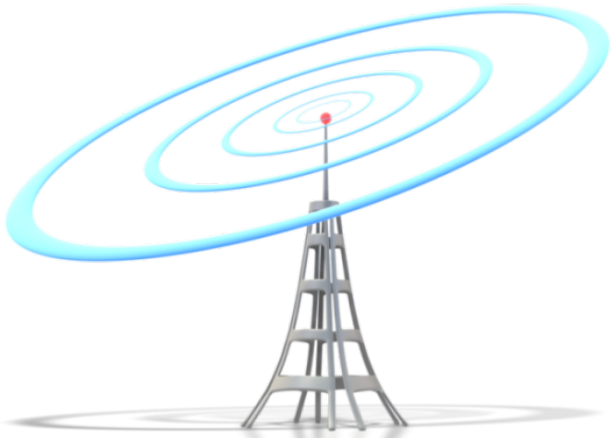
Pipe-Type Cable Installations

- With no power at pumping plants:
  1) Oil pressure drops and cable system cools
  2) Gas pockets formed in pipe
  3) Vacuum could develop inside the terminators and line pipe
  4) Could result in immediate electrical failure or damage to cable upon re-energization
- Locations of pipe-type cable installations and pumping plants should be known by dispatchers
- Pressures should be verified prior to re-energization if cable and pumping plants have been off

Load Restoration

Priority Customer Load

- Circuits with load identified by company
  - Governmental, military facilities
  - Medical facilities
  - Public health (Water, sewage pumping stations)
  - Public communications (TV, Radio)
  - Communication facilities (phone)
  - Law enforcement (police, fire)



Summary

- We have defined the types of Cranking Paths
- We have Identified what PJM refers to as Critical Loads
- We have discussed some concerns related to the restoration of offsite power to Nuclear stations during the restoration process
- We have discussed some concerns related to the restoration of power to pipe-type cable installations during a restoration process
- We have discussed the sequence of restoring power to critical customer loads during a restoration process

Black Start Generating Units

Objectives

At the end of this module the Student will be able to:

- Identify what PJM and NERC refer to as a Black Start Unit
- Identify how PJM determines the minimum Black Start Generation requirement for each transmission zone
- Identify how Black Start resources are procured in the PJM RTO
- List some guidelines for communicating with Black Start generating units during a system restoration
- Explains how PJM works with the TOs to identify cross-zonal coordination opportunities

Operation of Black Start Units

- NERC Definition of a Black Start Unit:
  - Generating unit that can start and synchronize to the system without having an outside (system) source of AC power

PJM Black Start Unit Requirements

- Must be tested annually
  - To ensure unit can start when requested from a “blackout” state
  - To ensure personnel are familiar with procedure
  - Have the ability to self-start without any outside source of power
  - Have the ability to close unit onto a dead bus within 3 hours of the request to start
  - Have the ability to run as defined by TO restoration plan
    - GOs must notify PJM and the TO if a critical blackstart fuel resource at max output falls below 10 hours
  - Have the ability to maintain frequency and voltage under varying load
  - The company must maintain black start procedures for each unit

PJM Black Start Unit Requirements

- Minimum Critical Black Start Requirement for each transmission zone consists of the following components:
  - Critical cranking power load
    - Units with a hot-start time of 4 hours or less (including the load required to supply scrubbers, where necessary)
  - Gas infrastructure critical load in the TO footprint
  - Nuclear station "safe shutdown" power requirements (One feed with a target of 4 hours)
  - Exceptions or additions to the criteria above will be allowed with PJM approval:
    - SOS-T endorsement will be sought for these exceptions and additions
    - One example could be to address coping power needs for steam units that cannot be supplied by resources other than black start
- **Required Black Start = 110% (Critical Load Requirement) on a locational basis**

PJM Black Start Unit Requirements

PJM Responsibilities:

- Ensure a minimum of two black start resources are “allocated” to each transmission zone with a critical load requirement
  - Not required to be physically located within the zone to which they are allocated
- In collaboration with the TOs,
  - Select Black Start units to meet Critical Load requirements during the 5-year Black Start Selection process
- Will utilize the Black Start Replacement Process, as described in PJM Manual M-14D for changes to Black Start availability or Critical Load requirements that occur within the 5-year period

PJM Black Start Unit Requirements

PJM Responsibilities:

- Transmission Operator (TOP)
  - Responsible for selecting the Black Start resources for a system restoration plan
- Works closely with the TOs to identify these units based on:
  - Critical Load requirements
  - Available Black Start resources
  - Minimum number of Black Start resources allocated to a zone
  - Possible cross zonal coordination opportunities
    - Manual 36: System Restoration Attachment A: Minimum Critical Black Start Requirement

PJM Black Start Unit Requirements

PJM Responsibilities:

- Utilize the start time parameters and test data to evaluate the Black Start resources
  - Will they meet the requirements of the restoration plans
  - May require some Black Start resources to adhere to less than a 3-hour start time given critical load restoration timing requirements
    - These units will be notified of this timing requirement and tested to it during annual Black Start testing
  - Resources with three hour start times may not be appropriate to meet nuclear power off-site safe-shutdown load restoration requirements
    - Target restoration time for off-site power to nuclear stations is 4 hours

Cross-Zonal Coordination

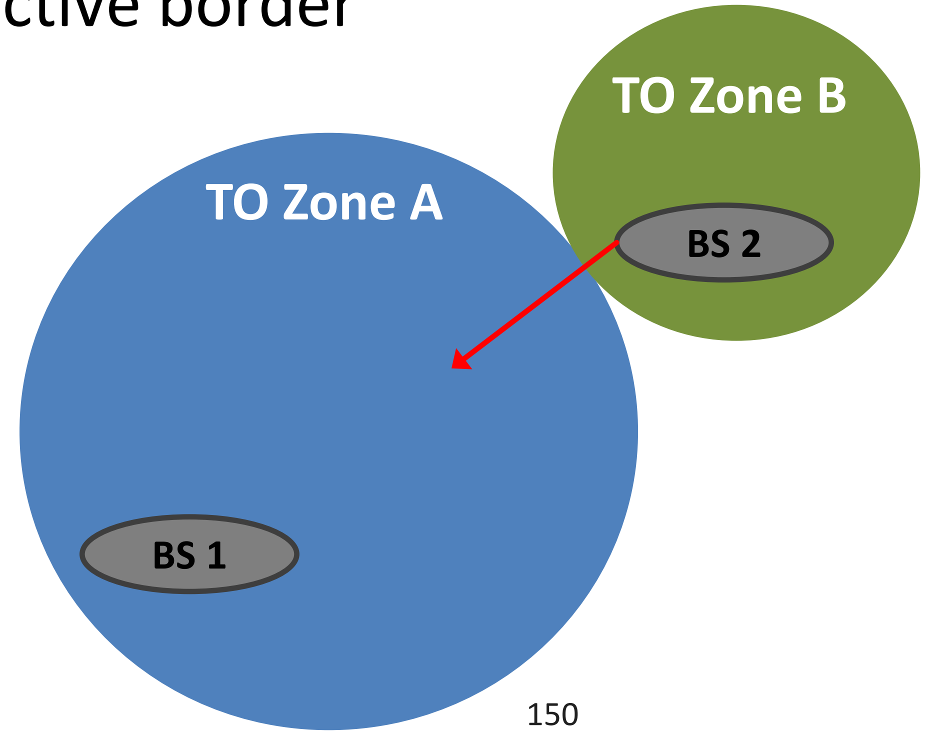
Cross-Zonal Coordination is identifying areas within the RTO where it would be beneficial to coordinate individual TO restoration plans. Benefits include:

- Reliability Requirements
  - Procuring sufficient Black Start resources to meet critical load requirements
  - Meeting critical load restoration timing requirements
  - Meeting redundancy requirements
- Efficiency opportunities
  - Speed of restoration
  - Cost savings

Cross-Zonal Coordination

Level One Cross-Zonal Coordination

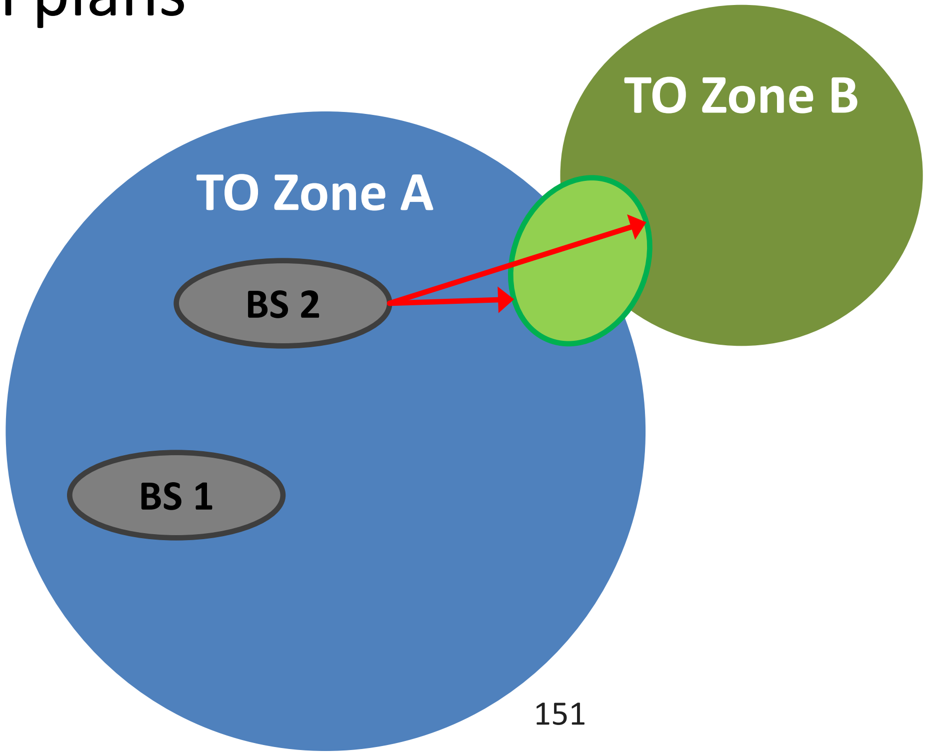
- Supplying Black Start generation from outside of a TO zone to meet that zones critical load requirements
- Both supplier and receiver will document the cranking path to their respective border



Cross-Zonal Coordination

Level Two Cross-Zonal Coordination

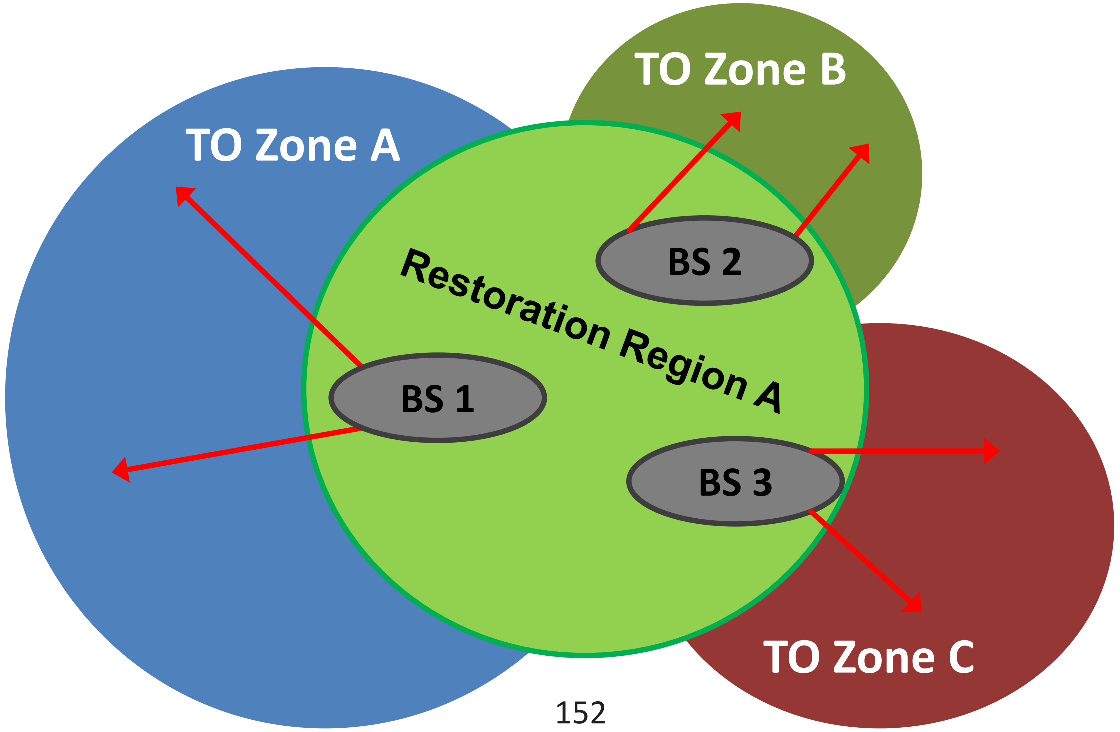
- Supplying Black Start generation critical and/or customer load pockets across TO zones
- Both TOs will document this coordination in their restoration plans



Cross-Zonal Coordination

Level Three Cross-Zonal Coordination

- Fully aggregate TO restoration plans into a combined plan for a newly defined Restoration region
  - Merging two or more existing TO zones
  - Only one restoration plan for the aggregated area



Black Start Unit Procurement

Member Responsibilities:

- Adjust its system restoration plan based on the Black Start units allocated to it from this selection process
- May procure additional Black Start resources (if not already procured by PJM)
  - Costs of these resources will be recovered, if necessary, outside of the PJM Open Access Transmission Tariff (OATT)

Black Start Unit Procurement

Member Responsibilities:

- Disagreement about the location, amount or number of Black Start resources, or between the supplying TO, receiving TO or PJM about cross zonal coordination, will follow this process:
  - Issue brought to the SOS-T for consultation
  - If the parties continue to disagree, referred to the Dispute Resolution Process as detailed in Schedule 5 of the PJM Operating Agreement
  - General notification of initiation and result of Dispute Resolution process will be given to the Operating Committee
- Under frequency Islanding Schemes and Load Rejection Schemes
  - Acceptable alternative to solely maintaining critical black start units, or
  - Can be utilized in conjunction with critical black start units as a means to serve critical load during restoration

Communications

- PJM policy is that – during a system restoration – Transmission Owners will direct the loading of all generation within their footprint
  - This includes both Black Start and conventional units
  - IPP units may participate when available, and to the extend their contracts permit
- Once PJM resumes control of an island, they will direct the operation and output of units

Communications

- Communication between the TO and the generating units is critical as the restoration progresses
- Generating plant personnel should be aware of certain evolutions, because of the potential effects on the generator, and the need for the generator operator to take controlling actions
  - Picking up significant blocks of load
  - Energizing long transmission lines, and the resulting voltage swings

Summary

- We have identified what PJM and NERC refer to as a Black Start Unit
- We have identified how PJM determines the minimum Black Start Generation requirement for each transmission zone
- We have described how Black Start Resources are procured
- We have listed some guidelines for communicating with Black State generating units during a system restoration

Coordinating Load Pickup

Objectives

At the end of this module the Student will be able to:

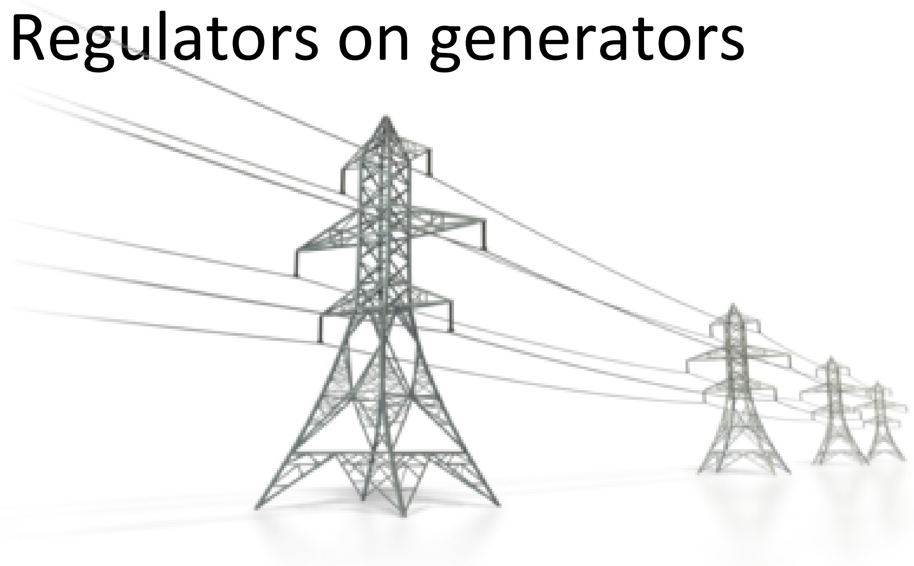
- Explain how to maintain voltages during the restoration process
- Describe the effects load pickup has on frequency
- Calculate frequency change and new frequency as a result of restoring load
- Describe what is meant by “Cold Load” and its characteristics
- Describe under-frequency load and its uses in the restoration process

Transmission Restoration

- Voltage Control
  - During restoration, operate so that reasonable voltage profiles (90% -105 % of nominal) are maintained
  - Where possible, maintain voltages at the minimum possible levels to reduce charging current
  - As transmission is energized, some load must be restored to reduce voltages. This could include:
    - Station light and power / auxiliary load
    - Shunt reactors / transformer excitation
    - Critical customer load
    - Generators / Synchronous condensers operating in the lead

Transmission Restoration

- Voltage Control
  - Shunt capacitors are removed until sufficient load (40%) has been restored to prevent high voltage
  - Shunt reactors
  - Automatic Static VAR Compensators
  - Automatic Voltage Regulators on generators



Load Restoration

- Frequency Control
  - Maintain frequency between 59.75 and 61.00 with an attempt to regulate toward 60.00
  - Increase frequency to 60.00 - 60.50 prior to restoring a block of load
  - Manual load shedding may need to be used to keep the frequency above 59.50
  - As a guide, shed approximately 6-10% of the load to restore the frequency 1 Hz

Load Restoration

- Frequency Control
  - Restore large blocks of load only if the system frequency can be maintained at 59.90 or higher
  - Restore load in small increments to minimize impact on frequency
  - Do not restore blocks of load that exceed 5% of the total synchronized generating capability
    - For example: If you have 1000 MW of generating capacity synchronized on the system, restore no more than 50 MW of load at one time

Load Restoration – Old Way

- Frequency Control
  - To estimate new frequency level following load pickup, use the following equation:
    - Frequency change = (Load Change/Connected capacity) * Governor Droop (In percent, not decimal)
    - New Frequency = Frequency prior to load pickup - Frequency change

Load Restoration – Old Way

- Frequency Control Example
  - When restoring 100 MW of load with 3000 MW of capacity, frequency change is:
    - (100 MW/3000 MW)(5) = (.033)(5) = .167 Hz
  - However, if restoring the same 100 MW of load with 2000 MW of capacity, frequency change is:
    - (100 MW/2000 MW)(5) = (.05)(5) = .25 Hz
  - Smaller systems have larger frequency fluctuations when restoring load

Load Restoration – New Way

- Frequency Control
  - To estimate new frequency change following load pickup, use the following equation:
    - Frequency Change =
      (Load Change/Connected capacity) * Governor Droop (in Hz)
    - New Frequency =
      Frequency prior to load pickup - Frequency change

Load Restoration – New Way

- Frequency Control Example
  - When restoring 100 MW of load with 3000 MW of capacity, frequency change is:
    - (100 MW/3000 MW)(3Hz) = (.033)(3) = .1 Hz
  - However, if restoring the same 100 MW of load with 2000 MW of capacity, frequency change is:
    - (100 MW/2000 MW)(3) = (.05)(3) = .15 Hz
  - Smaller systems have larger frequency fluctuations when restoring load

Load Restoration

Frequency Control

- Generators will trip off automatically due to:
  - Low Frequency at 57.50 Hz (under frequency relay)
    - High turbine blade vibration caused by harmonic resonance
  - High Frequency at 61.75 Hz (overspeed relay)

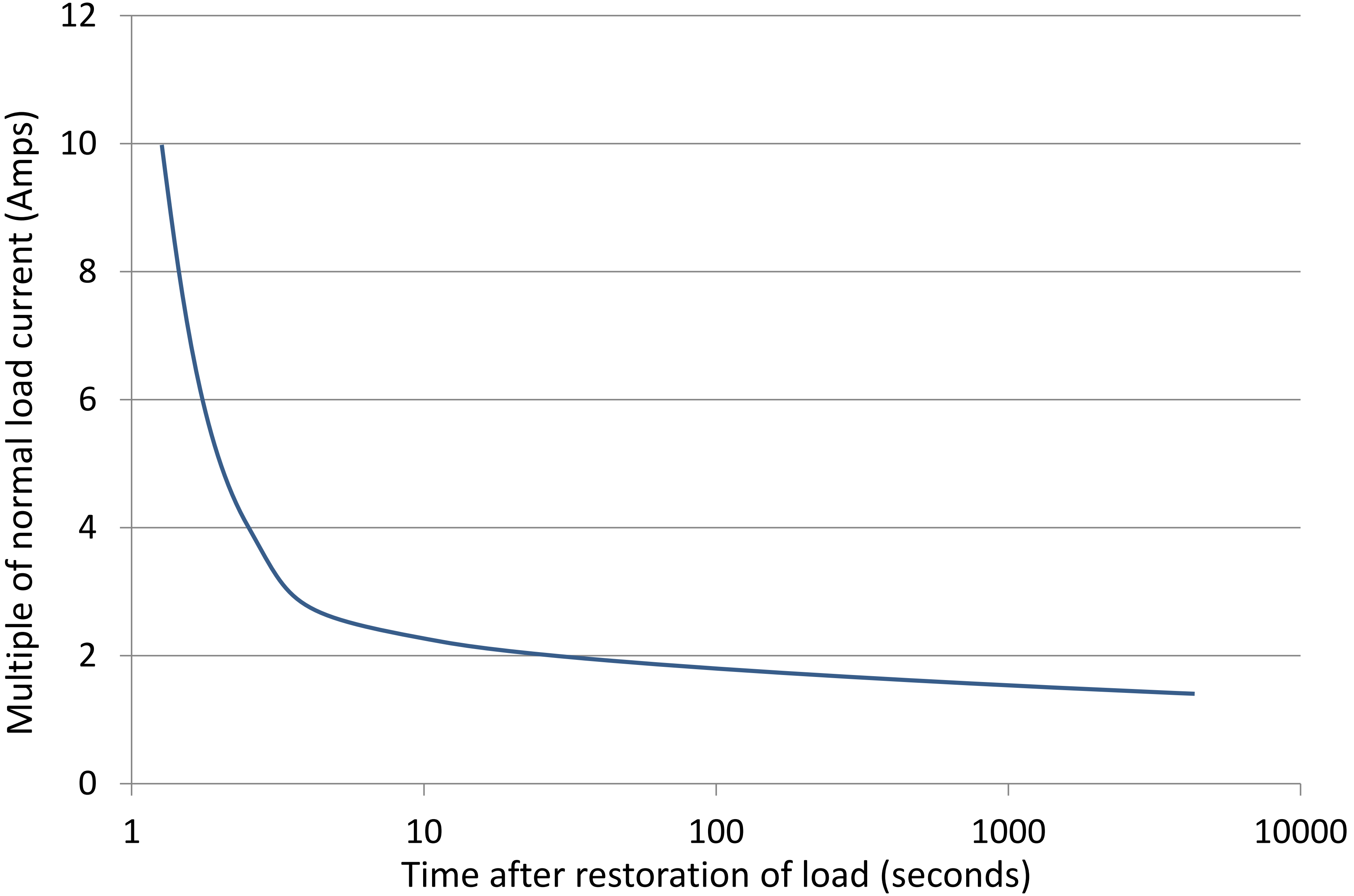
Load Restoration

- Cold Load
  - Load which has been off for some time which has lost its diversity (cycling characteristics)
    - Time for load to get "cold" depends on weather conditions and duration of outage
    - This type of load is typically thermostatically controlled or cyclic and includes air conditioners, heaters, refrigerators and pumps
  - Initial load current upon restoration can be as much as 10 times normal loading!
    - This is due to simultaneous starting of motors and compressors and light bulb filament heating

Load Restoration

- Cold Load
  - Effect of cold load will decay to about 2 times the normal load current in 2-4 seconds
  - Load current will remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes

Cold Load Pickup



Load Restoration

- Under-Frequency Load Shed
  - Feeder circuits equipped with relaying to automatically shed load if frequency decays below a specified level
  - Last resort to save system or island from frequency collapse
  - Considered as “Dynamic Reserve” (more later!)

Load Restoration

- Under-Frequency Load Shed
  - Load equipped with under-frequency relaying should **NOT** be restored in early stages of restoration
    - Large frequency swings early in restoration process
    - Activated under-frequency relaying may cause high frequency on the unstable system
  - U/F load may be restored once system frequency is consistently above trip levels upon load restoration
    - Add load with under-frequency relays set at the lowest setting
    - As generation base continues to grow, load should be added with under-frequency relays set at the higher settings

Load Restoration Exercises

Load Restoration Exercise

System Restoration progress:

Generating Capacity Synchronized = 1500 MW (5% droop)
System Load Restored = 1200 MW
System Frequency = 59.9 Hz

1) According to the rule of thumb for capacity, what is the maximum amount of load that should be restored at one time given the system conditions above?

(1500 MW capacity)(0.05) = 75 MW

2) If you were to restore the maximum amount of load calculated above, what will be the approximate new system frequency?

Change in frequency = (Load block/capacity online)(droop) = (75 MW/1500 MW)(3) = 0.15 Hz
New frequency = prior frequency - frequency change = 59.9 Hz - 0.15 Hz = 59.75 Hz

Load Restoration Exercise

3) Based on the Rules of Thumb, should we restore all 75 MW of load at once?

No; for restoring large blocks of load, frequency should remain above 59.9 Hz

4) At what frequency could you safely energize all 75 MW of load at once?

59.9 + 0.15 Hz = 60.05 Hz. Increase frequency to that or higher to safely energize that size block of load

Load Restoration Exercise

System Restoration progress:

Generating Capacity Synchronized = 1100 MW (5% droop)

System Load Restored = 900 MW

System Frequency = 59.48 Hz and dropping

5) What course of action do you recommend?

Shed load to restore frequency to at least 59.5 or higher and load remaining generation.
Shed 6 – 10% of load for 1 Hz frequency rise. This would be between 54 and 90 MW of load. To restore your frequency to 60 Hz you would need to shed between 35 and 47 MW

Frequency Control

Objectives

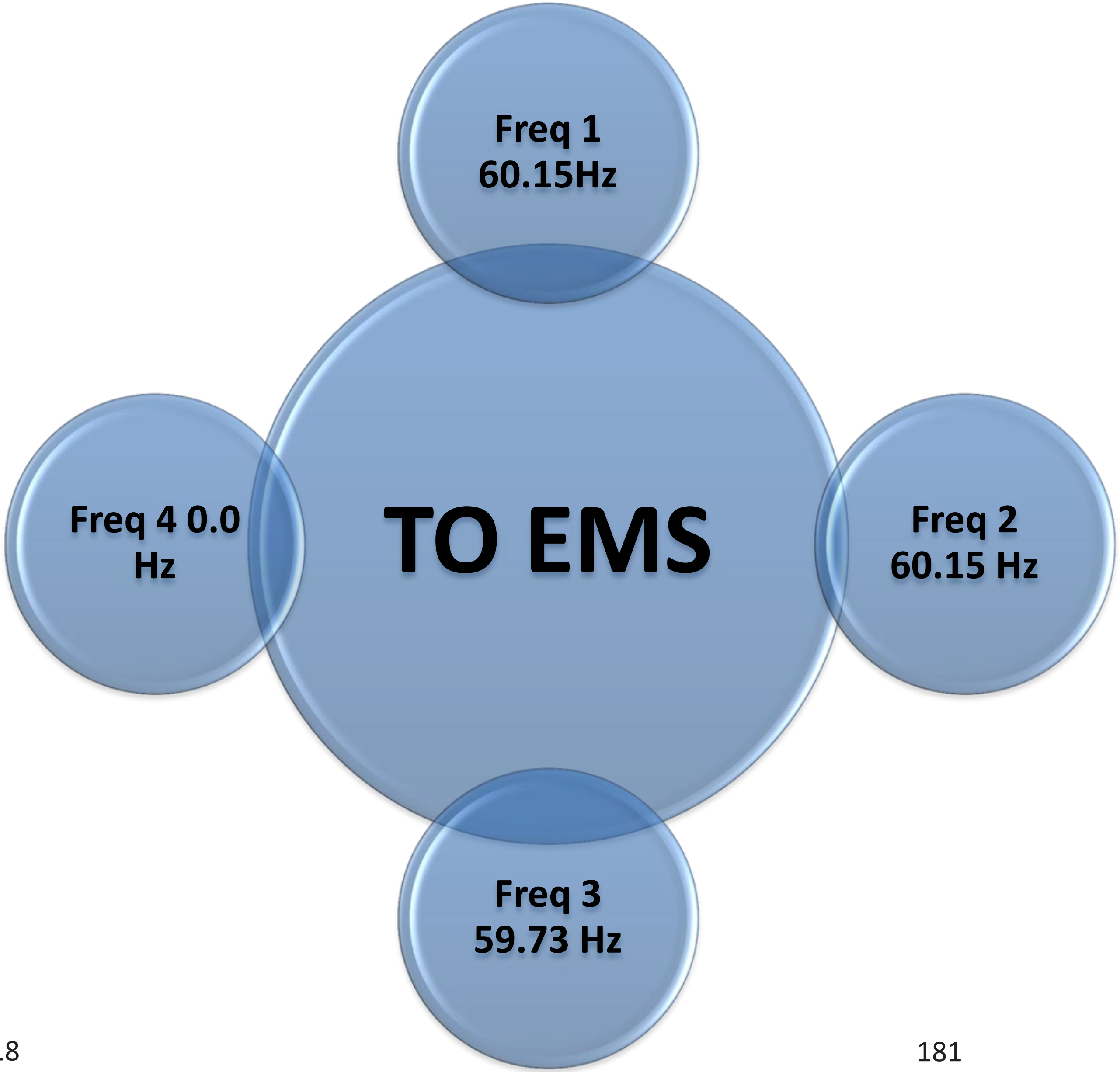
At the end of this module the Student will be able to:

- Interpret and monitor frequency signal across your system during the restoration

Frequency Monitoring

- Each TO must monitor frequency in their zone
  - Monitoring frequency at multiple points throughout the TO zone will provide better situational awareness when analyzing the boundaries of an event that has led to system separation
    - Operators should be able to determine the number of islands and boundary of the affected area using frequency along with other measurements
    - It is also important to know what source the frequency measurement is coming from

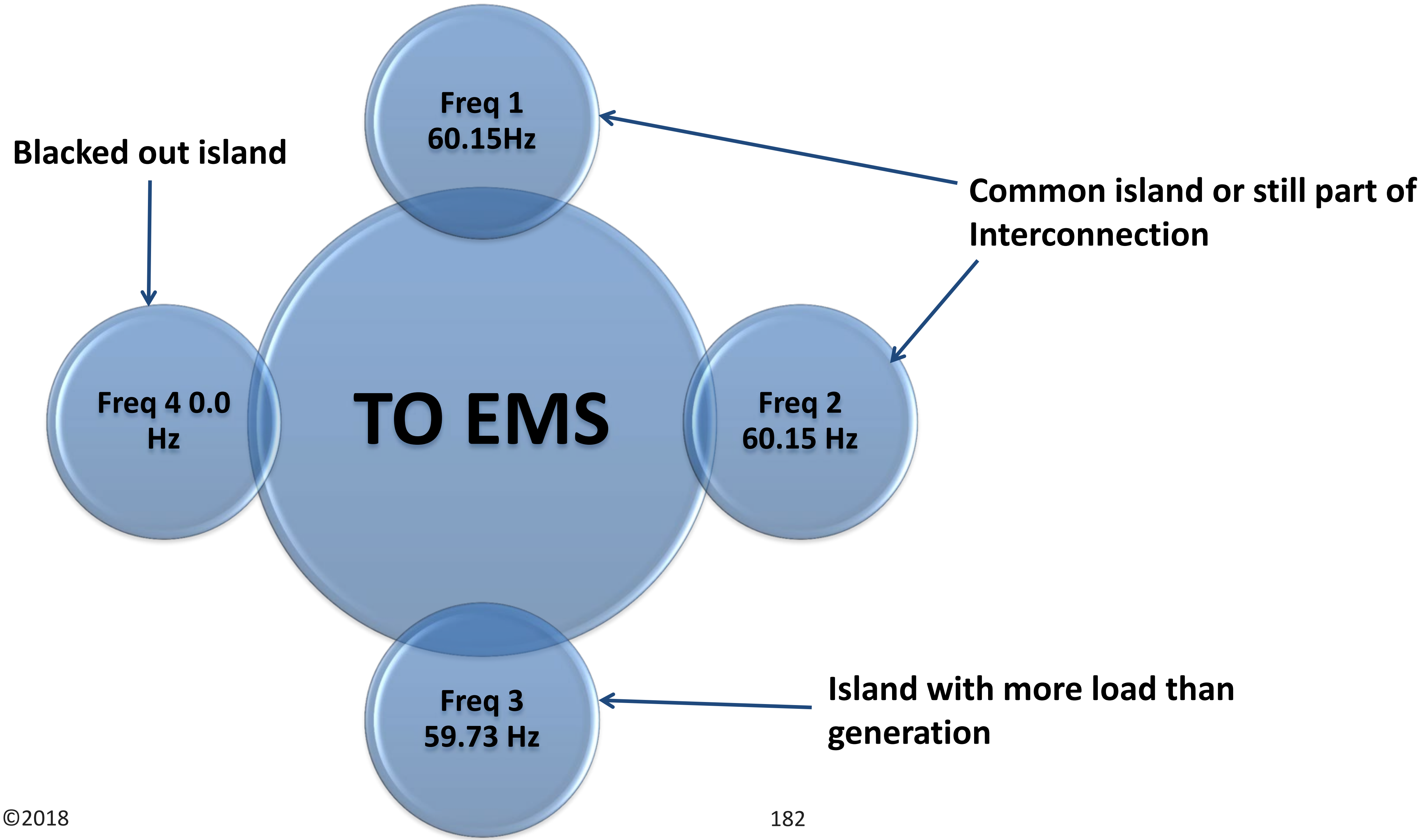
Frequency Monitoring



If a TO is monitoring four frequencies in their area after a system disturbance, and their EMS indicates the following:

- What can be deduced from these measurements?

Frequency Monitoring



Frequency Monitoring

- Frequency Monitoring
  - During system restoration, the frequency of each island that is created will need to be monitored to ensure the balance of generation and load
  - Frequency will also be critical when it is time to interconnect these islands, as it must match to prevent damage to equipment or the shutdown of the island(s)
    - Generation or load may have to be adjusted in the islands in order to match the frequencies
    - Monitoring those frequencies is critical to verify those adjustments are having the intended effect

Maintaining Adequate Reserves

Objectives

At the end of this module the Student will be able to:

- Define synchronous and dynamic reserves and their purpose during system restoration
- Given a set of system conditions, calculate dynamic reserve and determine if it is adequate for the given conditions

Reserves During Restoration

- Two categories of reserves to be monitored in system restoration:
  - Synchronous reserve
  - Dynamic reserve
    - Enables system to be operated safely upon the loss of the largest energy contingency
- Calculation of other reserve categories (quick start, operating, etc.) that are not required during a system restoration

Reserves During Restoration

- Synchronous Reserve
  - For a system restoration, Synchronous reserve is defined as:
    - On-line generation that can be loaded within 10 minutes **OR**
    - Load (including customer load) that can be shed manually in 10 minutes
  - Enough synchronous reserve must be carried to cover an area’s largest energy contingency
  - Largest contingency may or may not be the largest generator on the system
    - A transmission line carrying generation from a plant may cause more of a loss of generation than the loss of a single unit

Reserves During Restoration

- Dynamic Reserve
  - Amount of available reserve in order to preserve the system during a frequency disturbance
  - Amount of reserve must be enough to survive the largest energy contingency
  - Dynamic reserve consists of two components:
    - Reserve on generators that is available via governor action
    - Load with under-frequency relaying
  - Dynamic reserve is automatic, as opposed to synchronous reserve, which is manual
  - Dynamic reserve must be calculated for each island

Reserves During Restoration

- Dynamic Reserve from Generation
  - Amount of Dynamic Reserve needed is determined by generator "Load Pickup Factors" for units synchronized to the system
  - Load Pickup Factors = maximum load a generator can pick up as a percentage of generator rating without incurring a decline in frequency below safe operating levels (57.5 Hz)
  - "Rule of Thumb" load pickup factors are:
    - Fossil steam = 5% of unit's capacity
    - Hydro = 15% of unit's capacity
    - CTs = 25% of unit's capacity
    - **OR unloaded capacity, whichever is less**

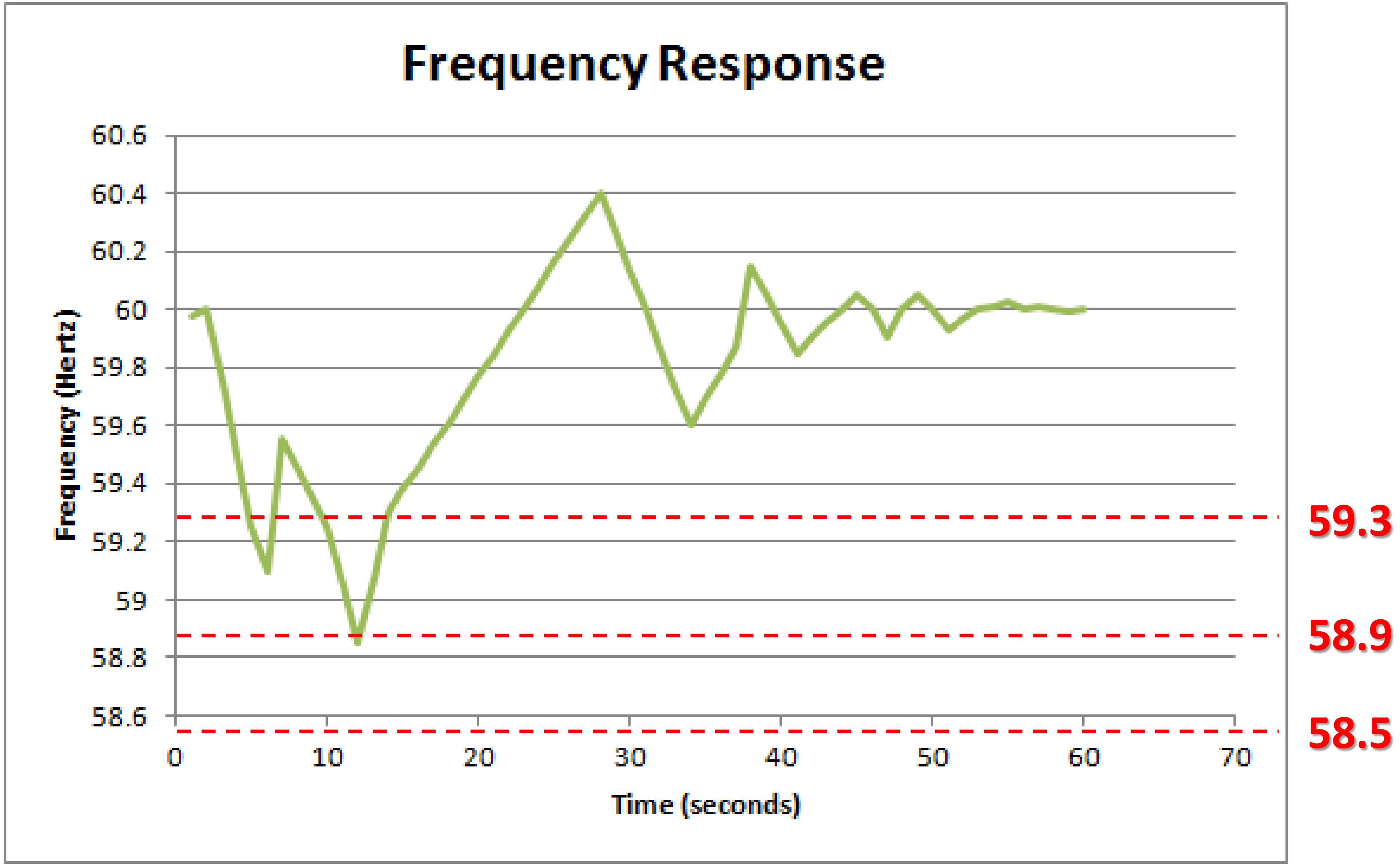
Reserves During Restoration

- Dynamic Reserve from Under-frequency relaying
  - Load is tripped at frequencies above where units are disconnected from the system (57.5 Hz)
  - Arrests further frequency decay
  - Results in “step-function” frequency recovery
  - Resist restoring under-frequency load early in restoration process due to unstable frequency
  - Under-frequency relay load should be no more than 50% of total Dynamic Reserve
    - If more U/F load is restored, can only take credit for up to 50% of total Dynamic Reserve

Reserves During Restoration

Early stages of restoration	→ Do not restore under-frequency load
As system becomes more stable and upon interconnection	→ Monitor dynamic reserves
As system becomes very large and stable	→ All parties agree to suspend dynamic reserve calculation

Reserves During Restoration



Reserves During Restoration

- Dynamic Reserve Sample Calculation
  - A system has 300 MW of steam capacity, 400 MW of CT capacity, and 100 MW of hydro capacity
  - The load pick-up factors are 5%, 25% and 15% respectively.
    50 MW of under-frequency load shed is restored.
    Largest contingency is a 100 MW steam unit

Governor Response

(5%)(300 MW) = 15 MW

(25%)(400 MW) = 100 MW

(15%)(100 MW) = <u>15 MW</u>

= 130 MW

Largest Contingency Adjustment

(5%)(100 MW) = - 5 MW

Governor Response Total

= 125 MW

U/F Load = <u>50 MW</u>

Dynamic Reserve = 175 MW

Dynamic Reserve Exercises

Exercise 1

Your system has 300 MW of steam capacity, 800 MW of combustion turbine capacity and 100 MW of hydro capacity with load pick-up factors of 5%, 25% and 15%, respectively. 70 MW of load with under-frequency relays has also been picked-up. The largest contingency is CT unit with 200 MWs of capacity. Determine the amount of dynamic reserve

Steam	(300 MW)(0.05) =	15 MW
CT	(800 MW)(0.25) =	200 MW
Hydro	(100 MW)(0.15) =	15 MW
	Unit Governor Response	230 MW
Largest Contingency	(-200 MW)(0.25)	-50 MW
	Total Governor Response	180 MW
	Under Frequency Relayed Load	70 MW
	Total Dynamic Reserve	250 MW

Exercise 2

Your system has 300 MW of steam capacity, 400 MW of CT capacity and 200 MW of hydro capacity. One of your CTs is fully loaded at 100 MW. You have 25 MW of under-frequency load restored. Your largest contingency is a 100 MW capacity hydro unit. What is your dynamic reserve?

Steam	(300 MW)(0.05) =	15 MW
CT	(400 MW)(0.25) =	100 MW
Hydro	(200 MW)(0.15) =	30 MW
	Unit Governor Response	145 MW
Largest Contingency	(-100 MW)(0.15) =	-15 MW
Fully Loaded CT	(-100 MW)(0.25) =	-25 MW
	Total Governor Response	105 MW
	Under Frequency Relayed Load	25 MW
	Total Dynamic Reserve	130 MW

Exercise 3

Your system has 400 MW of steam capacity, 200 MW of CT capacity and 100 MW of hydro capacity. A 100 MW CT Unit has a blocked governor. You have 60 MW of under-frequency load restored. Your largest contingency is a 200 MW capacity steam unit. What is your dynamic reserve?

Steam	**(400 MW)(0.05) =**	**20 MW**
CT	**(200 MW)(0.25) =**	**50 MW**
Hydro	**(100 MW)(0.15) =**	**15 MW**
	Unit Governor Response	**85 MW**
Largest Contingency	**(-200 MW)(0.05) =**	**-10 MW**
Blocked Governor	**(-100 MW)(0.25) =**	**-25 MW**
	Total Governor Response	**50 MW**
	Under Frequency Relayed Load	**60 MW**
	Total Dynamic Reserve	**100 MW**

Exercise 4

Your system has 300 MW of steam capacity, 1000 MW of CT capacity and 200 MW of hydro capacity. A 100 MW CT is currently loaded at 85 MW. You have 75 MW of under-frequency load restored. Your largest contingency is a 400 MW capacity CT unit. What is your dynamic reserve?

Steam	**(300 MW)(0.05) =**	**15 MW**
CT	**(1000 MW)(0.25) =**	**250 MW**
Hydro	**(200 MW)(0.15) =**	**30 MW**
	Unit Governor Response	**295 MW**
Largest Contingency	**(-400 MW)(0.25) =**	**-100 MW**
Partially Loaded CT Normally (100 MW) (0.25)= 25 MW	**Loaded @ 85 MW Only 15 MW of reserves remaining**	**-10 MW**
	Total Governor Response	**185 MW**
	Under Frequency Relayed Load	**75 MW**
	Total Dynamic Reserve	**260 MW**

Exercise 5

Your system has a 200 MW steam unit currently loaded at 150 MW, a 100 MW combustion turbine currently loaded at 75, and 100 MW hydro unit currently loaded at 50. Load pick-up factors are 5%, 25% and 15% respectively. 50 MW of load with under-frequency relays has also been picked-up. Determine the amount of dynamic reserve

Steam	**(200 MW)(0.05) =**	**10 MW**
CT	**(100 MW)(0.25) =**	**25 MW**
Hydro	**(100 MW)(0.15) =**	**15 MW**
	Unit Governor Response	**50 MW**
Largest Contingency	**(-200 MW)(0.05)**	**-10 MW**
	Total Governor Response	**40 MW**
	Under Frequency Relayed Load	**50 MW**
	Total Dynamic Reserve	**80 MW**

Exercise 6

Unit	Type	Capacity (MW)	Energy (MW)	Ramp Rate (MW/Min)	Synchronized Reserves (MW)	Total Reserve (MW)	Governor Reserve (MW)
A	Steam	150	100	4			
B	Steam	400	375	8			
C	Steam	300	200	4			
D	CT	100	75	3			
E	CT	50	20		20		
F	CT	15		5	0		
G	Hydro	10	5	5			
H	Hydro	50	40	5			
I	Hydro	20		3		15	
	Totals						
						Adjustment for largest contingency	
						Total Governor Reserve	
						Total Underfrequency Load MW	70
						Dynamic Reserve	

Exercise 6

Unit	Type	Capacity (MW)	Energy (MW)	Ramp Rate (MW/Min)	Synchronized Reserves (MW)	Total Reserve (MW)	Governor Reserve (MW)
A	Steam	150	100	4	**40**	**50**	**7.5**
B	Steam	400	375	8	**25**	**25**	**20**
C	Steam	300	200	4	**40**	**100**	**15**
D	CT	100	75	3	**25**	**25**	**25**
E	CT	50	20	**2**	20	**30**	**12.5**
F	CT	15	**15**	5	0	**0**	**0**
G	Hydro	10	5	5	**5**	**5**	**1.5**
H	Hydro	50	40	5	**10**	**10**	**7.5**
I	Hydro	20	**5**	3	**15**	15	**3**
	Totals	**1095**	**835**		**180**	**260**	**92**
						Adjustment for largest contingency	**-20**
						Total Governor Reserve	**72**
						Total Underfrequency Load MW	70
						Dynamic Reserve	**142**

Exercise 6

What issues do you see with the results in the previous table?

There is not enough Dynamic Reserve to cover the largest contingency (375 MW)

Coordinating Synchronization of Islands

Objectives

At the end of this module the Student will be able to:

- Identify the criteria used to determine stability of islands during system restoration
- Describe the pre-tie preparations necessary in order to synchronize two islands
- Describe the criteria that has to be met in order to synchronize two islands
- Describe the post-tie actions that are taken
- Describe the PJM and Member company synchronization actions

Island Interconnection

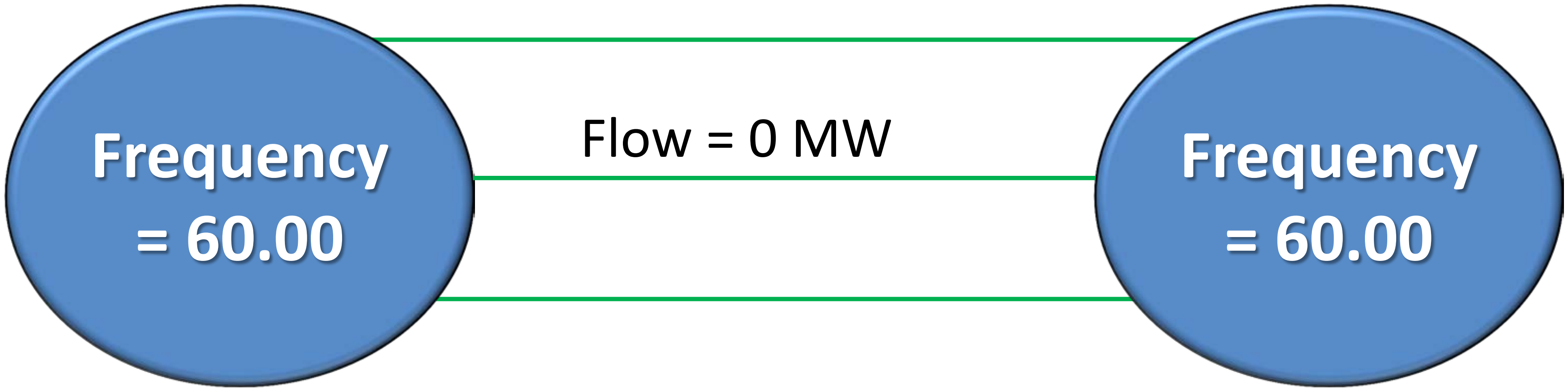
- Islanded systems must be stable before attempting to interconnect with another company
  - PJM Interconnection Checklist is designed to ensure this (more later)
- Interconnection of a small stable island with a small unstable island will most likely result in a larger, but still unstable area
- If island is connecting to Eastern Interconnection, synchronism is still required, but stability issues are less of a concern

Island Interconnection

- How do I know if my system is stable?
  - Voltage within limits
  - Small voltage deviations when restoring load or transmission
  - Frequency within 59.75 and 61.0
  - Small frequency deviations when restoring load
  - Adequate reserves (synchronous and dynamic)
  - Significant amount of U/F relayed load picked up

Island Interconnection

- Pre-Tie Preparations
  - Identify transmission line to tie area together
    - Must be able to handle expected flow on tie



Island Interconnection

- Pre-Tie Preparations
  - Identify substation and circuit breaker to use for synchronism
    - Circuit breaker must be equipped with either synchro-check relay or synchroscope availability
  - Ensure reliable communications between field personnel, control center and generating stations
  - Agree upon tie schedule

Island Interconnection

- Synchronization
  - Islands cannot be connected unless they are in synchronism
    - Frequencies of islands must match
    - Voltage magnitudes and phase angles must match
  - Synchro-check relay
    - Measures voltage on each side of breaker
    - Set for angular difference (~20 degrees) with timer
    - Will only prevent closure if out of synchronism
      - Will not synchronize!
  - Synchroscope
    - Permits manual closing of breaker when two systems are in sync

Island Interconnection

- Synchronization
  - Frequency and voltage of the *smaller* island should be adjusted to match the frequency and voltage of larger island
    - Frequency and voltage in a smaller system are able to be moved more easily with smaller generation shifts
  - Failure to match frequency and voltage between the two areas can result in:
    - Significant equipment damage, and
    - Possible shut-down of one or both areas

Island Interconnection

- Post-synchronism
  - If possible, close any other available tie-lines between the two newly connected systems to strengthen stability
  - The larger company will control frequency while the other company(s) will control tie-line schedule
    - Larger company has more resources to control frequency
    - Large company will run flat frequency control
    - Other company(s) will run tie line control

Island Interconnection

- Benefits of Island Interconnection
  - Provides a more stable combined system
    - More system inertia
    - Enables quicker load pickup
  - Allows for sharing of reserves
    - Reserves allocated based on share of total capacity
  - Allows for supply of cranking power or energy for load among connected areas
  - Additional AGC control and regulation

Any opportunity to connect to the Eastern Interconnection should be taken!

Island Interconnection

- Expectations of Interconnected Island
  - Cranking power should be supplied to requesting companies as a priority to restoring native load
  - Companies/areas that have restored all native load (or never lost it) are expected to consider supplying both cranking power ***and*** energy for load to requesting system
    - Up to normal operating limits
    - As long as security of supplying company is not compromised

Member Interconnection

PJM Actions:

- Act as a coordinator and disseminator of information relative to the availability of generation and transmission
- Keep Members apprised of developing system conditions to assist in the formation and on-going adjustments of restoration plans to take advantage of the additional information
- Provide Members with updated run-of-river hydroelectric capability
- Coordinate with neighboring RCs and TOPs to establish external interconnections and establish tie schedules

Member Interconnection

Member Actions:

- Prior to synchronizing, each TO must ascertain that adequate reserves are available to cover the largest contingency within the interconnected area
  - Frequency of the smaller area is adjusted to match the frequency of the larger area
  - Area voltages and frequencies are controlled as close as possible prior to synchronization
  - Phase angle deviation of the voltages are as close to zero as possible
- TO’s may share reserves and agree on a plan to act in a coordinated manner to respond to area emergencies

Member Interconnection

Member Actions:

- Identification of the coordinating TO controlling Flat-Frequency control and,

19	Which company will control frequency?	

- Identification of the TO controlling Flat Tie-Line control

20	Which company will control tie-line flow?	

- During a restoration process, does your company have the capability to control either Flat Frequency, or Flat Tie Line?

Member Interconnection

Member Actions:

- Frequency is maintained between 59.75 Hz and 61.0 Hz, adjusting it slightly above 60 Hz prior to picking up load
- Synchronous Reserve and manual load dump is used to keep frequency above 60 Hz
  - 6-10% load shed to restore frequency 1.0 Hz
- Dynamic Reserve is allocated/assigned proportionally to the available Dynamic Reserve in each area

Member Interconnection

Member Actions:

- After synchronization, the TO's continue to strengthen and stabilize the interconnected area by the closure of additional TO-to-TO tie lines
- As additional areas are added to the interconnected area, reserve assignments and regulation shall be recalculated and reassigned
- TO's/GO's continue to maintain communications with PJM to provide updated status of system conditions, in addition to the hourly report

Interconnection Checklist

INTERCONNECTION CHECKLIST

DATE:		TIME:	
ISLAND "A":		ISLAND "B":	
CONTACT:		CONTACT:	

INFORMATION EXCHANGE

			ISLAND "A"		ISLAND "B"	
1	Are you currently interconnected?		YES	NO	YES	NO
2	If YES, which company (ies)					
3	Existing Tie-line schedules					
	FROM:	TO:		MW		MW
	FROM:	TO:		MW		MW
	FROM:	TO:		MW		MW
4	Do you need start-up power?		YES	NO	YES	NO
4a	If YES, how much?			MW		MW
5	Can you supply energy?		YES	NO	YES	NO
5a	If YES, how much?			MW		MW

LOAD INFORMATION

		ISLAND "A"		ISLAND "B"	
6	Load Restored		MW		MW
6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:	Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

CAPACITY / ENERGY INFORMATION

		ISLAND "A"	ISLAND "B"
8	Largest Engery Contingency	MW	MW
9	Generation On-line: *Total Capacity*	MW	MW
10	Generation On-line: *Energy*	MW	MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):	MW	MW
12	Governor Reserve:	MW	MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)	MW	MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	- Hz	- Hz

TIE-LINE LOCATION AND SCHEDULING INFORMATION

15	Tie-line to be established:		
16	Tie-line schedule to be established:		MW
17	Which company will coordinate synchronization?		
18	Which breaker / substation will be used for synchronization?		
19	Which company will control frequency?		
20	Which company will control tie-line flow?		
21	Voltage At Boundary Buses:	kV	kV
22	Relay or SPS concerns @ sync locations?		

SYNCHRONIZATION

23	What time will synchronization occur?		
23a	Contact name:		
23b	Phone #:		
24	What is maximum amount of load pick-up without notification?	MW	MW
25	Conditions that would cause the opening of the tie-line:		

ADDITIONAL

Member Interconnection Scenarios

1. Member Company Transmission Owner connecting to another Member Company Transmission Owner within the RTO

2. Member Company Transmission Owner connecting with an external entity:
   - Islanded TO connecting to Eastern Interconnection

3. Cross Zonal Coordination:
   - Black Start of one zone supplying critical load of adjacent zone

(1) Interconnection Checklist (TO to TO)

INTERCONNECTION CHECKLIST					
DATE:		TIME:			
ISLAND "A":		ISLAND "B":			
CONTACT:		CONTACT:			
INFORMATION EXCHANGE					
				ISLAND "A"	ISLAND "B"
1	Are you currently interconnected?			YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
2	If YES, which company (ies):				
3	Existing Tie-line schedules				
	FROM:	TO:		MW	MW
	FROM:	TO:		MW	MW
	FROM:	TO:		MW	MW
4	Do you need start-up power?			YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
	4a	If YES, how much?		MW	MW
5	Can you supply energy?			YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
	5a	If YES, how much?		MW	MW
LOAD INFORMATION					
6	Load Restored			MW	MW
	6a	% of Load Restored		%	%
7	Load Restored With Underfrequency Relaying Enabled:			Hz MW	Hz MW
				Hz MW	Hz MW
				Hz MW	Hz MW
				Hz MW	Hz MW
	7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW	MW

(1) Interconnection Checklist (TO to TO)

	CAPACITY / ENERGY INFORMATION							
8	Largest Engery Contingency			MW				MW
9	Generation On-line: ***Total Capacity***			MW				MW
10	Generation On-line: ***Energy***			MW				MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):			MW				MW
12	Governor Reserve:			MW				MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)			MW				MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36		Hz		-		Hz
	TIE-LINE LOCATION AND SCHEDULING INFORMATION							
15	Tie-line to be established:							
16	Tie-line schedule to be established:							MW
17	Which company will coordinate synchronization?							
18	Which breaker / substation will be used for synchronization?							
19	Which company will control frequency?							
20	Which company will control tie-line flow?							
21	Voltage At Boundary Buses:			kV				kV
22	Relay or SPS concerns @ sync locations?							
	SYNCHRONIZATION							
23	What time will synchronization occur?							
	23a Contact name:							
	23b Phone #:							
24	What is maximum amount of load pick-up without notification?			MW			10	MW
25	Conditions that would cause the opening of the tie-line:							

(2) Interconnection Checklist (TO to Eastern Interconnection)

INTERCONNECTION CHECKLIST

DATE:		TIME:	
ISLAND "A":		ISLAND "B":	
CONTACT:		CONTACT:	

INFORMATION EXCHANGE

			ISLAND "A"	ISLAND "B"
1	Are you currently interconnected?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
2	If YES, which company (ies):			
3	Existing Tie-line schedules			
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
4	Do you need start-up power?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
4a	If YES, how much?		MW	MW
5	Can you supply energy?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
5a	If YES, how much?		MW	MW

LOAD INFORMATION

		ISLAND "A"		ISLAND "B"	
6	Load Restored		MW		MW
6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:	Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

(2) Interconnection Checklist (TO to Eastern Interconnection)

CAPACITY / ENERGY INFORMATION					
8	Largest Engery Contingency		MW		MW
9	Generation On-line: ***Total Capacity***		MW		MW
10	Generation On-line: ***Energy***		MW		MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):		MW		MW
12	Governor Reserve:		MW		MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)		MW		MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36	Hz	-	Hz
TIE-LINE LOCATION AND SCHEDULING INFORMATION					
15	Tie-line to be established:				
16	Tie-line schedule to be established:				MW
17	Which company will coordinate synchronization?				
18	Which breaker / substation will be used for synchronization?				
19	Which company will control frequency?				
20	Which company will control tie-line flow?				
21	Voltage At Boundary Buses:		kV		kV
22	Relay or SPS concerns @ sync locations?				
SYNCHRONIZATION					
23	What time will synchronization occur?				
23a	Contact name:				
23b	Phone #:				
24	What is maximum amount of load pick-up without notification?		MW	10	MW
25	Conditions that would cause the opening of the tie-line:				

(3) Interconnection Checklist (Cross Zonal Coordination)

INTERCONNECTION CHECKLIST			
DATE:		TIME:	
ISLAND "A":		ISLAND "B":	
CONTACT:		CONTACT:	

INFORMATION EXCHANGE

			ISLAND "A"	ISLAND "B"
1	Are you currently interconnected?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
2	If YES, which company (ies):			
3	Existing Tie-line schedules			
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
	FROM:	TO:	MW	MW
4	Do you need start-up power?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
4a	If YES, how much?		MW	MW
5	Can you supply energy?		YES ☐ Check NO ☐ Check	YES ☐ Check NO ☐ Check
5a	If YES, how much?		MW	MW

LOAD INFORMATION

		ISLAND "A"		ISLAND "B"	
6	Load Restored		MW		MW
6a	% of Load Restored		%		%
7	Load Restored With Underfrequency Relaying Enabled:	Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
		Hz	MW	Hz	MW
7a	*Total Load Restored w/ Underfrequency Relaying In-Service*		MW		MW

(3) Interconnection Checklist (Cross Zonal Coordination)

	CAPACITY / ENERGY INFORMATION						
8	Largest Engery Contingency		MW				MW
9	Generation On-line: ***Total Capacity***		MW				MW
10	Generation On-line: ***Energy***		MW				MW
11	Synchronous (Spinning) Reserve (Not including Load Shedding):		MW				MW
12	Governor Reserve:		MW				MW
13	Total Dynamic Reserve: (Governor Reserve + Total Restored Underfrequency Relaying) (Row 7a + 12) (N/A if company is tied to the Eastern Interconnection)		MW				MW
14	Frequency Range over the Last Hour: (N/A if company is tied to the Eastern Interconnection)	-N36	Hz		-		Hz
	TIE-LINE LOCATION AND SCHEDULING INFORMATION						
15	Tie-line to be established:						
16	Tie-line schedule to be established:						MW
17	Which company will coordinate synchronization?						
18	Which breaker / substation will be used for synchronization?						
19	Which company will control frequency?						
20	Which company will control tie-line flow?						
21	Voltage At Boundary Buses:		kV				kV
22	Relay or SPS concerns @ sync locations?						
	SYNCHRONIZATION						
23	What time will synchronization occur?						
	23a Contact name:						
	23b Phone #:						
24	What is maximum amount of load pick-up without notification?		MW			10	MW
25	Conditions that would cause the opening of the tie-line:						

Coordinating Frequency and Tie Line Control

Objectives

At the end of this module the Student will be able to:

- Demonstrate how to coordinate frequency and tie line control with interconnected systems

PJM System Control

- Manual Control
  - No ACE is calculated
  - Regulation dispatched manually via ALL-CALL
  - Frequency controlled manually
  - Any required load shedding assigned on a proportional basis based on load
  - Emergency procedures initiated as required

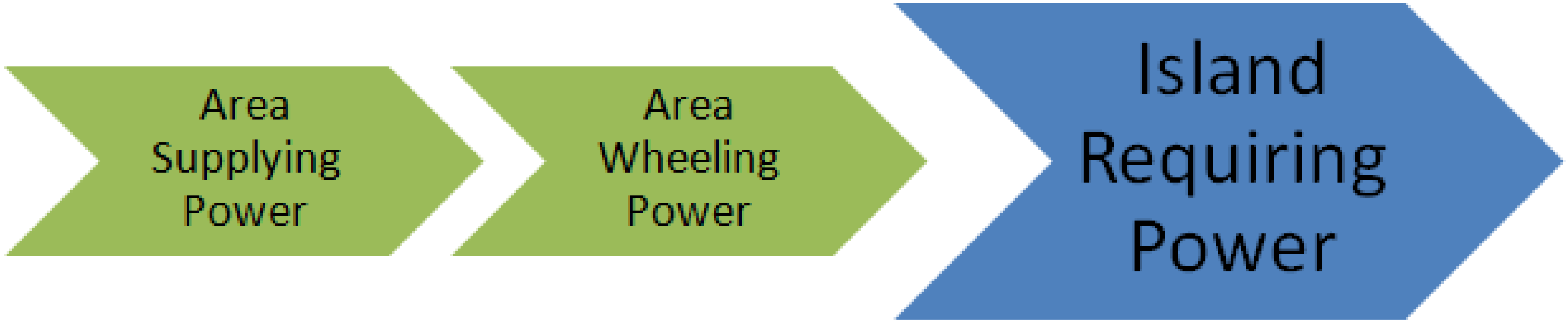
PJM System Control

- Flat Frequency Control
  - If PJM not connected (or on diesel), frequency can be manually entered
  - Frequency bias setting (1% of load) must be readjusted as load changes
  - Automatic regulation is now possible

PJM System Control

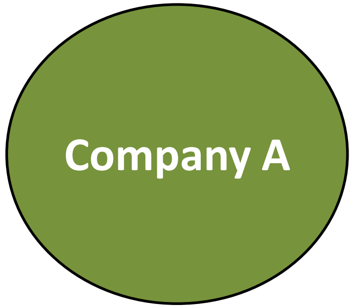
- Tie-Line Bias Control
  - Used when control area to control area tie lines are in service
  - This is the normal control mode
  - Frequency bias (1% of load) needs to be adjusted as load changes
  - PJM will facilitate delivery of energy from remote systems

$$ACE = (\textit{Frequency Deviation}\ (HZ) * \textit{Frequency Bias}\ (MW/_{0.1\ HZ}) * 10) + (\textit{Tie Schedule} - \textit{Tie Actual})$$



PJM System Control

- Single Island



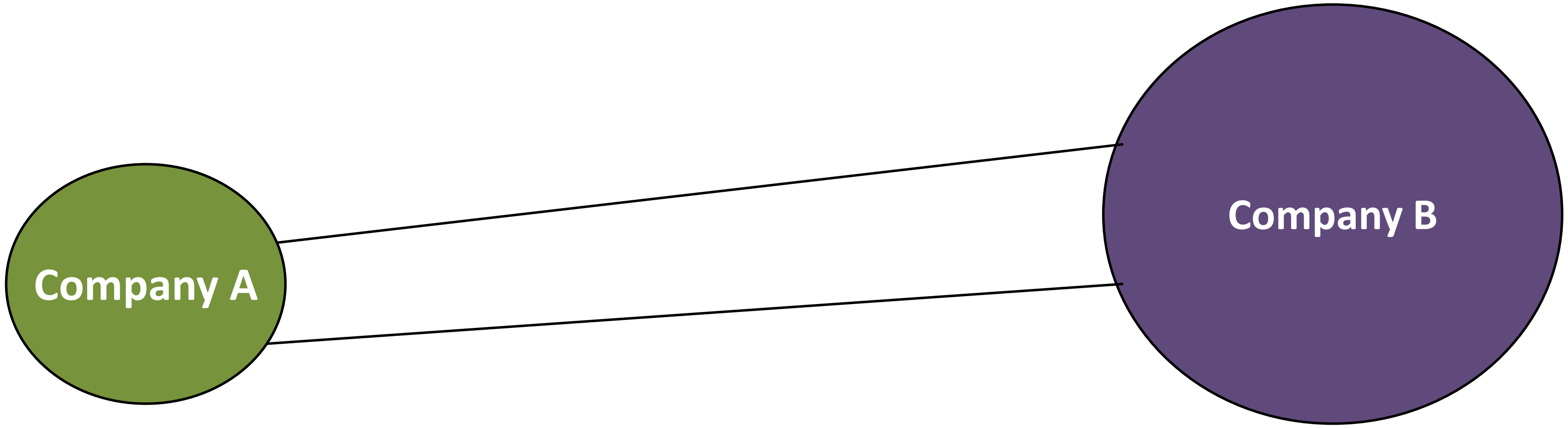
Flat Frequency Control

Requires: Frequency Source, Frequency Bias

Frequency Bias = (0.01)(Company A Load)

PJM System Control

- Multiple Islands



Flat Tie Line Control

Requires: Tie Line Schedule, Actual Tie line flow

ACE = (Tie Schedule - Tie Actual)

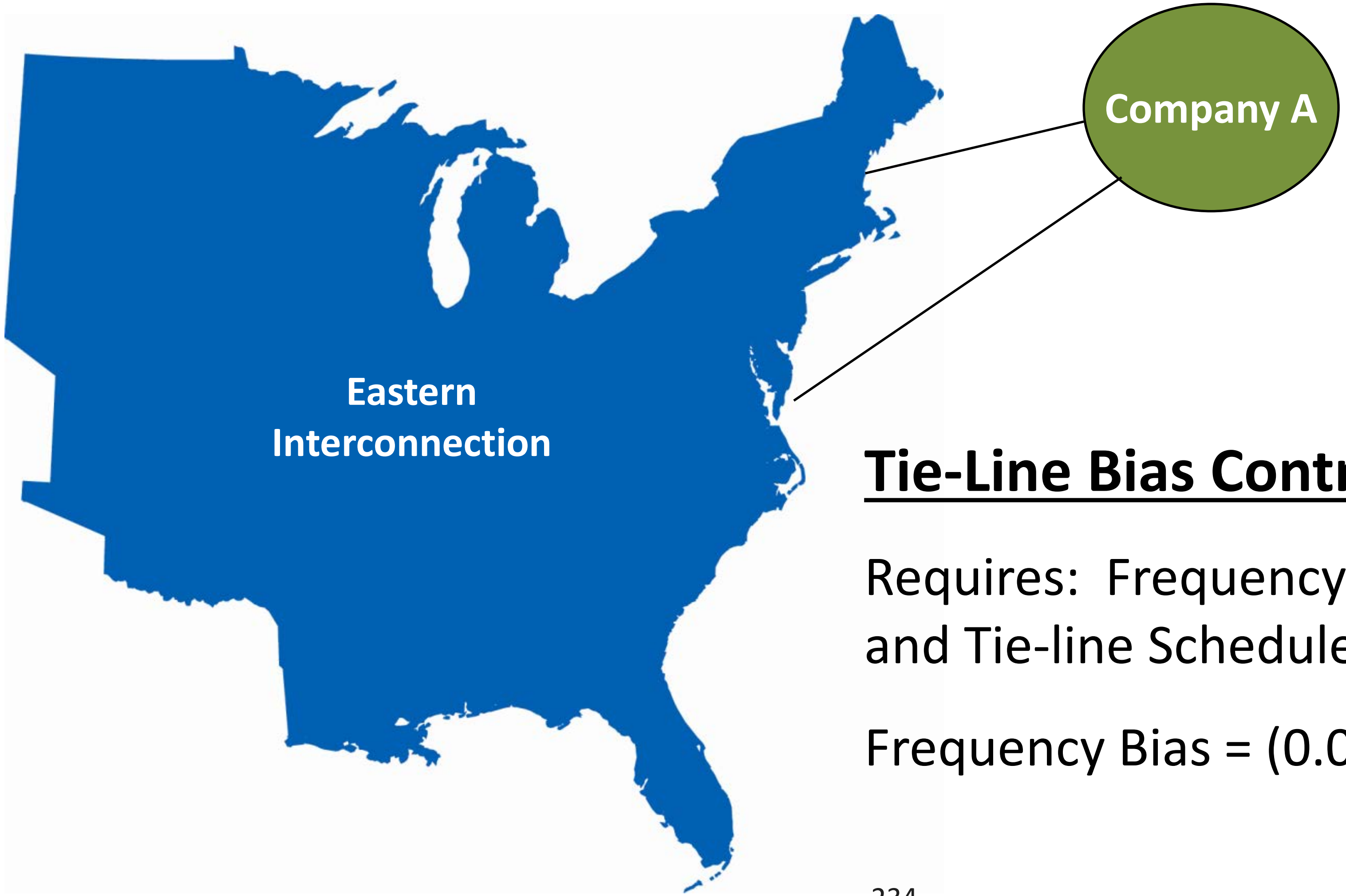
Flat Frequency Control

Requires: Frequency Source, Frequency Bias

Frequency Bias = (0.01)(Total System Load)

PJM System Control

- If Company A has synchronized generation



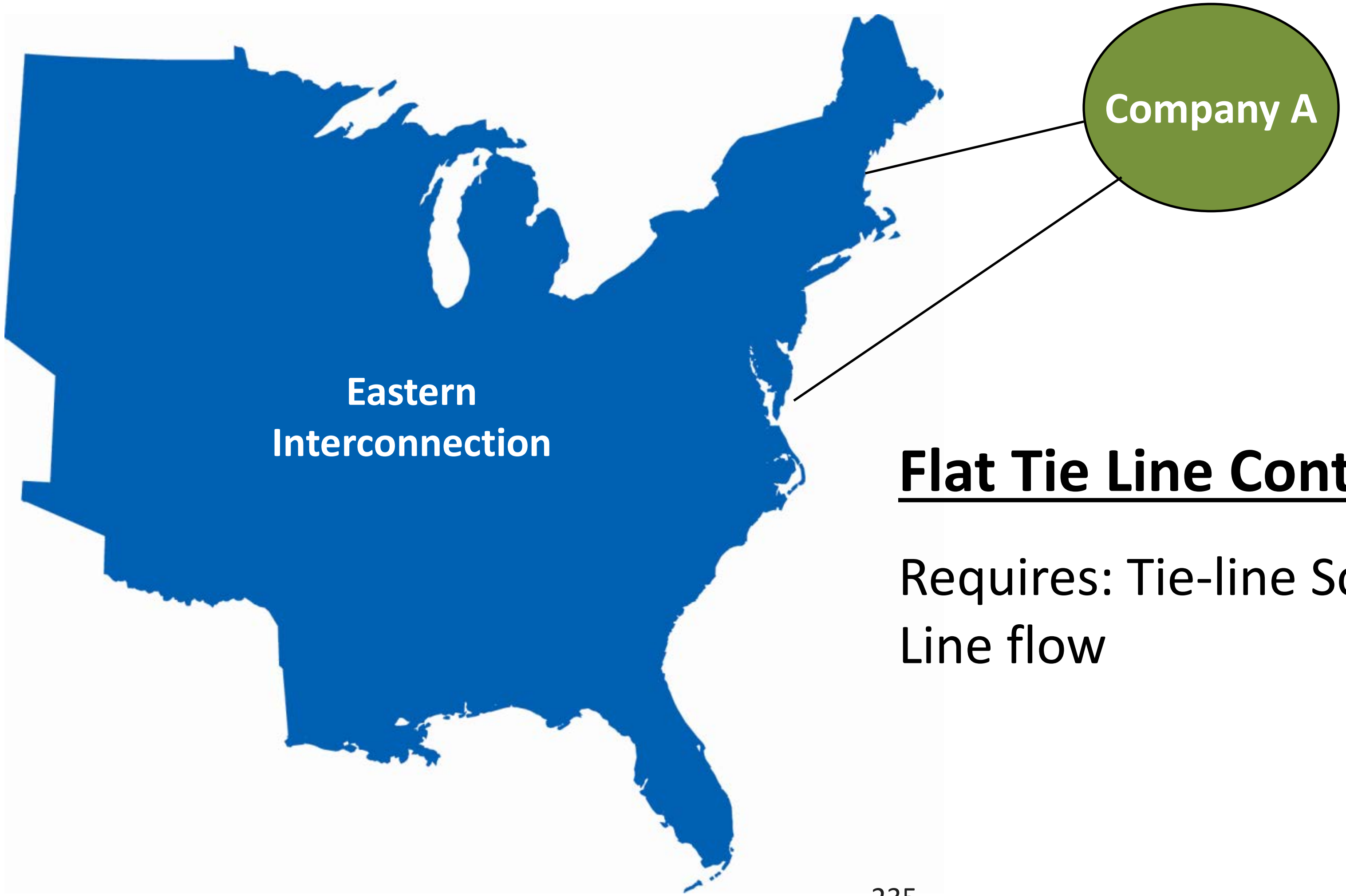
Tie-Line Bias Control

Requires: Frequency Source, Frequency Bias and Tie-line Schedules and Actual Tie Line flow

Frequency Bias = (0.01)(Company A Load)

PJM System Control

- If Company A is radial load:

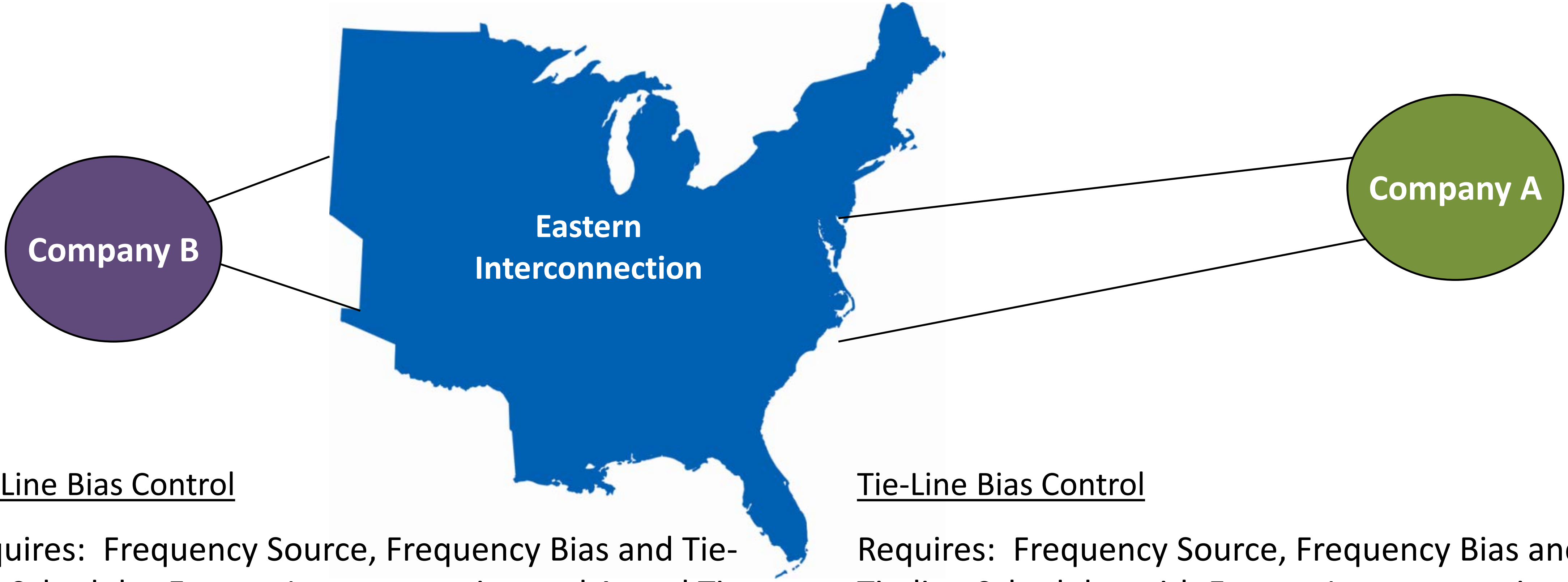


Flat Tie Line Control

Requires: Tie-line Schedules and Actual Tie Line flow

PJM System Control

- Two Companies with Synchronized Generation



<u>Tie-Line Bias Control</u>

Requires: Frequency Source, Frequency Bias and Tie-line Schedules Eastern Interconnection and Actual Tie line flows with Eastern Interconnection

<u>Tie-Line Bias Control</u>

Requires: Frequency Source, Frequency Bias and Tie-line Schedules with Eastern Interconnection and Actual Tie line flows with Eastern Interconnection

PJM System Control

- When conditions permit, PJM will notify TO that PJM Control Area is returning to normal operation:
  - Free flowing internal ties
  - Generation under AGC control
  - Control area tie line control
  - Published regulation and reserve requirements

Identifying Minimum Source Guidelines

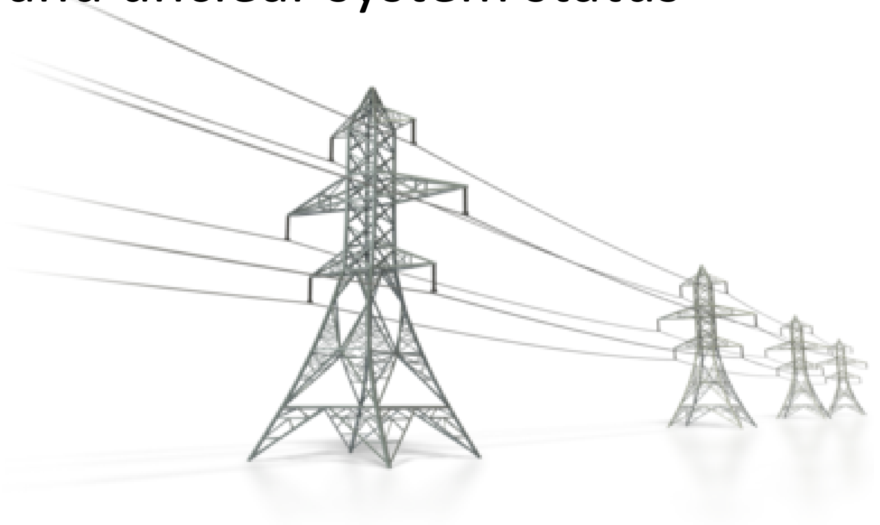
Objectives

At the end of this module the Student will be able to:

- Describe EHV energizing concerns during system restoration
- Describe the Minimum Source guidelines used during system restoration
- Given a set of system conditions, determine if the minimum source guidelines are sufficient to energize a line

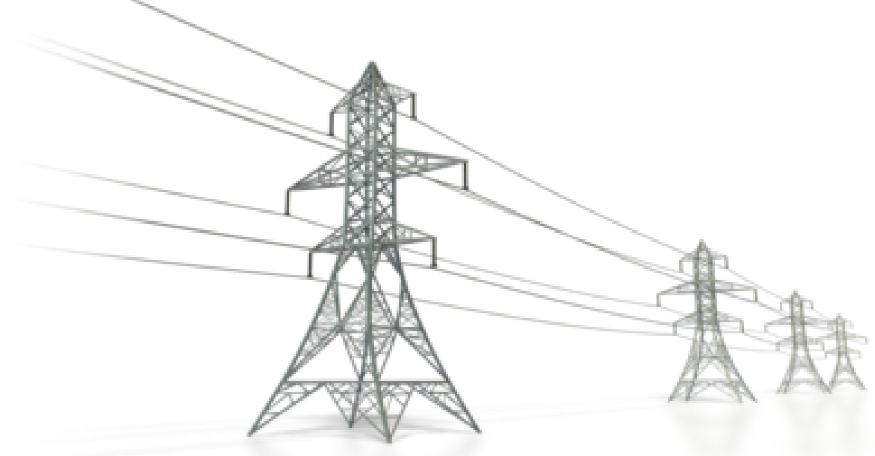
Transmission Restoration

- EHV Energization Concerns
  - Steady-state overvoltage caused by excessive MVAR supply from the capacitance of the EHV line
  - Reduction in proper relaying protection reliability due to insufficient fault current
    - Critical in restoration due to higher probability of faulted equipment due to overvoltage and unclear system status

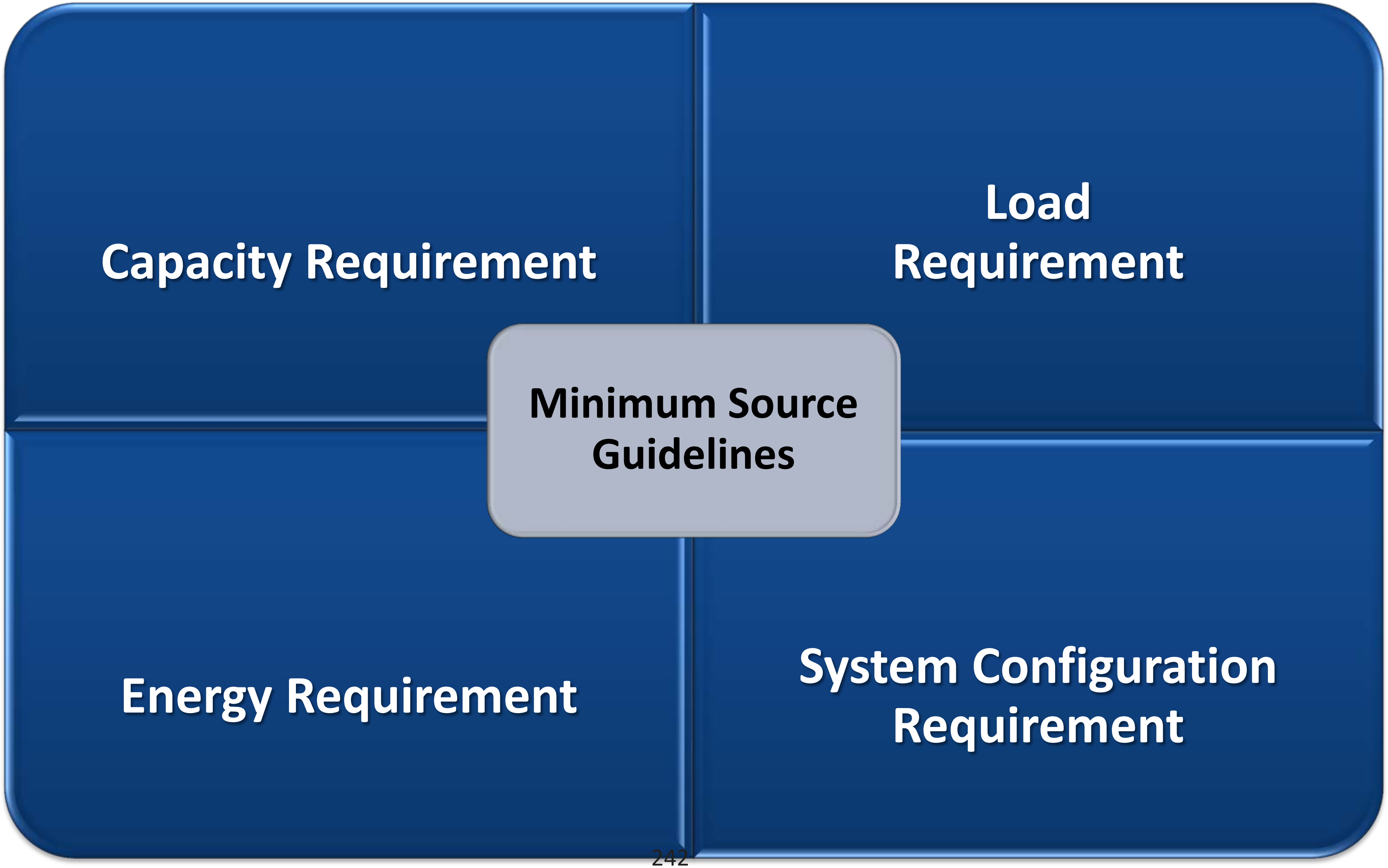


Transmission Restoration

- "Minimum Source Guidelines"
  - Requirements that must be met prior to the energization of EHV transmission
  - Identified to prevent or reduce the EHV energization concerns listed on the previous slide
  - PJM has established minimum source requirements for energization of 500 & 765 kV lines



Transmission Restoration



Transmission Restoration

- PJM 500 & 765 kV Minimum Source Guidelines
  - Primary and backup relays in service
  - Shunt capacitors out of service
  - Generation
    - 600 MW of electrically close generation (energy) connected at 230 kV or higher
      - Electrically close is defined as less than 50 230 kV miles
      - Provides adequate short circuit current for fault clearing
    - Minimum of 30 MW of generation (capacity) per mile of energized 500 or 765 kV
      - Provides approximately 2 MVAR/mile VAR absorbing capability

Transmission Restoration

- PJM 500 & 765 kV Minimum Source Guidelines: Load
  - Minimum of 20 MW of load per mile of energized 500 or 765 kV line
    - Energized line = Already energized + Line being energized
    - Provides approximately 1.8 MVAR/mile VAR load
    - Helps balance the capacitive voltage rise

Transmission Restoration

PJM 500 & 765 kV Minimum Source Guidelines: Example

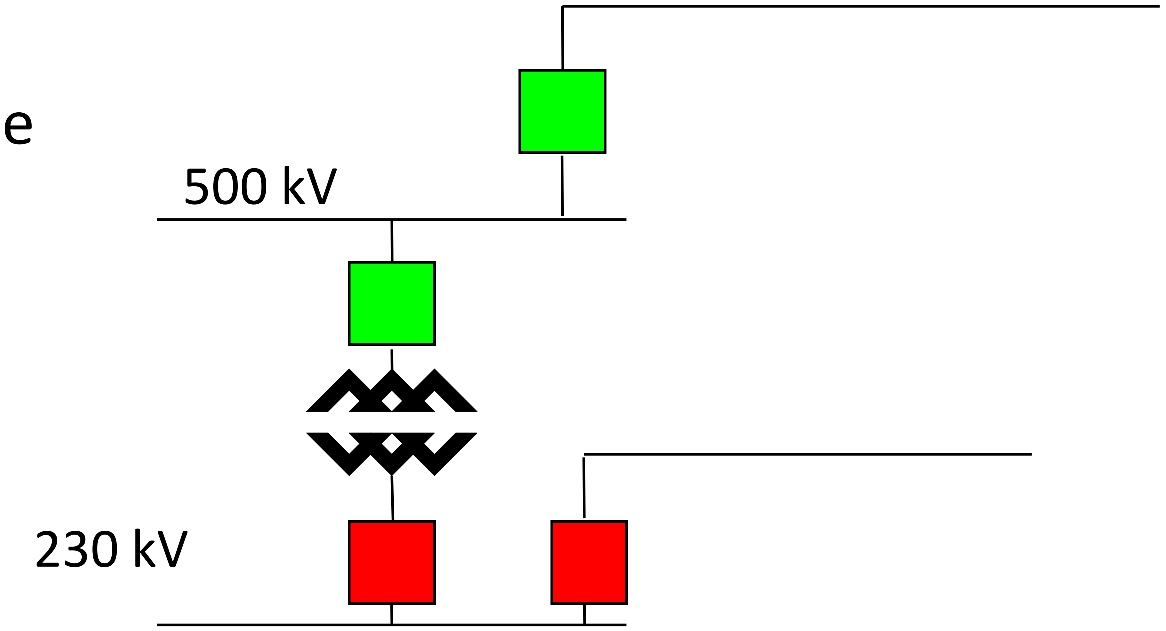
- You have 1200 MW of load restored, 1700 MW of generating capacity and your frequency is 60.00
- All your relays are in service and capacitors are switched off
- You wish to energize a 50 mile 500 or 765 kV line
- Do you meet all the minimum source guidelines?

Transmission Restoration

- PJM 500 & 765 kV Minimum Source Guidelines: Example
  - Required Energy for fault current clearing = 600 MW
    - You have 1200 MW load at 60.00 Hz - Condition Met!
  - Required Load for Mvar absorption = 20 MW/mile
    - (50 miles)(20 MW/mile) = 1000 MW load required
    - We have 1200 MW of load - Condition met!
  - Required Capacity for Mvar absorption = 30 MW/mile
    - (50 miles)(30 MW/mile) = 1500 MW capacity required
    - We have 1700 MW of capacity - Condition met!

Transmission Restoration

- Other switching considerations
  - Energize 500 & 765 kV lines and transformers separately.
    - Helps prevent dynamic overvoltage due to transformer saturation and harmonics
    - Energize transformers from low side to allow for use of transformer tap changer to reduce voltage



Transmission Restoration

- Other switching considerations
  - Add load to energized lines prior to energizing additional transmission lines
  - Energize only lines that will carry significant load
    - Prevents unwanted MVARS

Transmission Restoration

Transmission Line Charging

Nominal Voltage	Charging MVAR/Mile
69 kV Line	0.025
115/138 kV Line	0.100
230 kV Line	0.300
345 kV Line	0.800
500 kV Line	1.700
115/138 kV Cable	2.0-7.0
230 kV Cable	5.0-15.0
345 kV Cable	15.0-30.0

Minimum Source Guidelines Exercises

Minimum Source Guidelines Exercise

For the following scenarios, assume that no detailed load flow analysis is available to analyze the situations described below. Also, assume all generation and load is electrically close to the energization point, all shunt capacitors are out of service and all protective relaying is in service

1) You would like to energize a 70 mile long 500 kV line. You currently have 1600 MW of generation capacity and 900 MW of load connected to the system. The 500/230 kV transformer that you want use to energize the 500 kV line has a broken tap changer. Determine if the minimum source guidelines are met and if you should proceed

Energy Requirement	600 MW of electrically close load	900 MW	Condition met
Capacity Requirement	(30 MW/mile)(70 miles) =	2100 MW	Not Enough
Load Requirement	(20 MW/mile)(70 miles) =	1400 MW	Not Enough
Configuration Requirement	Broken tap changer would not allow you to adjust voltage		

Minimum Source Guidelines Exercise

2) You have energized a 500/230 kV transformer from the 230 kV system and have adjusted the taps to reduce the voltage on the 500kV system to 475 kV. You would like to energize 20 miles of 500 kV line. You currently have 650 MW of generating capacity and 350 MW of load connected to the system. Determine if the minimum source guidelines are met and if you should proceed

Energy Requirement	600 MW of electrically close load	350 MW	Not Enough
Capacity Requirement	(30 MW/mile)(20 miles) =	600 MW	Condition Met
Load Requirement	(20 MW/mile)(20 miles) =	400 MW	Not Enough

Minimum Source Guidelines Exercise

3) You currently have 20 miles of 500 kV transmission energized. You are considering energizing an additional 40 mile 500 kV line. You have 2500 MW of generation capacity and 1500 MW of load connected to the system. Your 500 kV voltage is around 510 kV. Determine if the minimum source Guidelines are met and if you should proceed

Energy Requirement	**600 MW of electrically close load**	**1500 MW**	**Condition met**
Capacity Requirement	**(30 MW/mile)(60 miles) =**	**1800 MW**	**Condition met**
Load Requirement	**(20 MW/mile)(60 miles) =**	**1200 MW**	**Condition met**

Minimum Source Guidelines Exercise

4) You currently have a 30 mile 500 kV transmission line energized. You are considering energizing an additional 40 mile 500 kV line. You have 2500 MW of generation capacity and 1500 MW of load connected to the system. Your 500 kV voltage is around 505 kV. Determine if the minimum source Guidelines are met and if you should proceed

Energy Requirement	**600 MW of electrically close generation**	**1500 MW**	**Condition met**
Capacity Requirement	**(30 MW/mile)(70 miles) =**	**2100 MW**	**Condition met**
Load Requirement	**(20 MW/mile)(70 miles) =**	**1400 MW**	**Condition met**

Minimum Source Guidelines Exercise

5) You currently have a 15 miles 500 kV line energized, 3000 MW of generation capacity, 1760 MW of load connected to the system and your 500 kV voltage is currently around 515 kV. What is the longest length of 500kV line that you can additionally energize?

Total length of line based on capacity requirement: $\frac{3000}{30} = 100$

Total length of line based on load requirement: $\frac{1760}{20} = 88$

Since 88 is less then 100 then we can only energize 88 total miles of line, since we already have 15 miles of 500kV energized the additional distance that we can add would be $88 - 15 =$ 73 miles long of a 500kV line

Transferring Control Back to PJM

Objectives

At the end of this module the Student will be able to:

- Identify when to transfer control back to PJM at a certain stage of the restoration

PJM Assumes Control

- PJM assumes control of an area when:
  - Control of the area becomes too burdensome for any one TO
  - PJM desires to assume control to facilitate EHV restoration or establish tie lines with adjacent system
  - Requested by a Member
- PJM needs accurate system status information prior to assuming control of the restoration!

PJM Assumes Control	
Date:	Time:
Reporting Company:	
Regulation MW	Synchronous Reserve MW
Frequency Controlled by:	Frequency Maintained From to HZ

Dynamic Reserves:

Underfrequency Relays:

Percent at 59.5 HZ_____% Percent at 59.3 HZ_____% Percent at 59.1 HZ_____%
Percent at 59.0 HZ_____% Percent at 58.9 HZ_____% Percent at 58.7 HZ_____%
Percent at 58.5 HZ

Governor Response:

Steam MW CT's MW Hydro MW

Load Pick - up Factors: Steam Units **5%** CT's **25%** Hydro Units **15%**

Total Load with Underfrequency Relaying __________MW
Total Governor Response: __________MW
Total Dynamic Reserves: MW

INTERCHANGE SCHEDULES (Company To Company, Company To Outside)

From Co.	To Co.	MW	From Co.	To Co.	MW

Connected Load	
765 kV MW of Connected Load MW	
500 kV MW of Connected Load MW	
345 kV MW of Connected Load MW	
230 kV MW of Connected Load MW	

Comments:
____
____
____
____
____
____

Exhibit 17: PJM Assumes Control

PJM Assumes Control

PJM Actions:

- Assimilates required information on reporting form
- Determines required Dynamic and Synchronous reserve for area based on largest contingency
  - Assign reserve proportional to capacity
- Determine regulation requirement
  - 2% of interconnected area load
  - Assign regulation proportional to connected load
- Coordinate hydro operations
- Monitor unit capabilities

PJM Assumes Control

Member Actions:

- Continue returning generation and load to maintain frequency
- Report returning units to PJM dispatcher
- Maintain established tie scheduled with other TOs until PJM returns to free-flowing tie conditions
- Respond to emergency procedures as initiated by PJM
- TO requests PJM approval prior to the closure of any reportable transmission line or a line that establishes an interconnection to an external system

PJM Assumes Control

Member Actions:

- Coordinate with PJM any change to pre-existing schedules (internal or external)
- Maintain communications with PJM dispatcher to provide updated status of system conditions in addition to the hourly report

Contact Information

PJM Client Management & Services

Telephone: (610) 666-8980

Toll Free Telephone: (866) 400-8980

Website: www.pjm.com

The Member Community is PJM's self-service portal for members to search for answers to their questions or to track and/or open cases with Client Management & Services

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