Case 14-E-0270

Petition Requesting Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant, LLC.

Hearing Exhibit 45 (Corrected Version)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant **Case 14-E-0270**

Citizens' Environmental Coalition's Second Set of Information Requests directed to Department of Public Service

1. a. Please provide any and all engineering information, evaluations and/or analyses received by DPS from RG & E or its consultants pertaining to the GRTA (Ginna Retirement Transmission Alternative) under development since Dec. 1, 2014.
   b. Please provide a record of meetings or discussions in the form of notes, presentations or written materials pertaining to status updates on the GRTA since Dec. 1, 2014.

Response:

Note: some of the documents overlap between Questions 1a and 1b, and consequently are included in one or the other.

1. a. See attached (note, some materials are deemed CONFIDENTIAL).

   b. See attached.

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December 23, 2014

Hon. Elizabeth H. Liebschutz
Hon. Michelle L. Phillips
State of New York Department of Public Service
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 11-T-0534 - Application of Rochester Gas and Electric Corporation for a Certificate of Environmental Compatibility and Public Need for the Construction of The "Rochester Area Reliability Project," Approximately 23.6 Miles of 115 Kilovolt Transmission Lines and 1.9 Miles of 345 Kilovolt Line in the City of Rochester and the Towns of Chili, Gates and Henrietta in Monroe County

Dear Judges Liebschutz and Phillips:

Rochester Gas and Electric Corporation ("RG&E") submits this letter to notify you and all parties to the Rochester Area Reliability Project ("RARP") proceeding that developments in Case 14-E-0270, Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant, will result in a modification of the RARP construction schedule.

R.E. Ginna Nuclear Power Plant, LLC ("Ginna") claims in Case 14-E-0270 that it has become uneconomic to continue to operate the Ginna Plant and sell the plant's power at market rates. Ginna states that to keep the plant in operation, it must enter into a Reliability Support Services Agreement ("RSSA") with RG&E. The Public Service Commission ("Commission"), in its November 14, 2014 Order Directing Negotiation of a Reliability Support Services Agreement and Making Related Findings ("Order Directing Negotiations"), required RG&E to negotiate an RSSA with Ginna and report back to the Commission by January 15, 2015. Any such agreement is likely to require RG&E to pay above-market rates for the plant's output during the period the Ginna Plant is required for the provision of reliable electric service. This would increase the amount RG&E's customers must pay for electric service.

To minimize the duration of this impact on its customers, RG&E issued a request for proposals ("RFP") for alternatives to an RSSA with Ginna on October 6, 2014. RG&E also evaluated transmission alternatives to an RSSA. In the Order Directing Negotiations, the Commission said:

> To the extent that alternatives proposed through the RFP might affect entry into an RSSA, or the period for which the RSSA remains in effect, RG&E, in consultation with Staff, would evaluate if viable, cost effective substitutes for the Facility, including generation, transmission, and other resources, would be available and could commence operations in a timely fashion. * * * * If it is determined that alternatives could affect negotiation of the RSSA, RG&E should redirect the RSSA negotiations to accommodate the alternatives. For example, an alternative might reduce the time period for which the Ginna Facility is needed, resulting in a shorter term for the RSSA.

Order Directing Negotiations, p. 24. RG&E has identified a transmission solution set that will allow for the retirement of the Ginna facility and could minimize the term of an RSSA, provide net financial benefit to RG&E's customers, and strengthen RG&E's system - the Ginna Retirement Transmission Alternative ("GRTA"). The GRTA can be constructed relatively quickly and would allow RG&E to maintain reliability following the proposed retirement of the Ginna plant. The GRTA mitigates the urgency of the RARP and addresses other system reliability matters, such as identified stuck breaker contingencies.

The New York Independent System Operator ("NYISO") identified Station 122 and Station 80 transformer overloads under N-1-1 stuck breaker contingency conditions (loss of three elements) in its 2012 and 2014 Reliability Needs Assessments. NYISO identified the RARP as a solution to these overloads under contingency conditions. As shown in the Engineering Justification for the RARP (Exhibit 28 in support of the Joint Proposal), the RARP was designed to meet load growth and planned or forced outages at the Ginna Plant. It was not designed to address the retirement of the Ginna Plant. In its December 16, 2013 "Update on Project Need and Major Milestone Schedule for Completion of Project," RG&E advised the Commission that "other additional system upgrades are necessary besides the RARP."

Peak load on the RG&E system in 2014 was 1,508 MW. Under present conditions, if the Ginna Plant were retired, RG&E's system would not meet reliability standards, and Station 122 transformers would be overloaded during both normal "all facilities in service" conditions and post-contingency conditions when the RG&E system load exceeds 1,430 MW. Even with the RARP in service, with the Ginna Plant off-line, Station 122 transformers would be overloaded during normal conditions with RG&E system loads above 1,550 MW. Furthermore, reconsideration of the siting of Station 255 of the RARP by the Commission has delayed the construction of Station 255.[1] The reliability need to solve the overloads that would result from the retirement of the Ginna Plant is immediate.

[1] With the implementation of the GRTA, the immediate construction of Station 255 will not be necessary. However, when Station 255 is constructed, it should be at Site 7 - the site the Commission has already certified for Station 255. Locating Station 255 at Site 20 would require the relocation of a Class C stream, substantial impacts to forested wetlands, the elimination of six acres of dormant agricultural land that has been farmed at Site 20 and could be returned to agriculture, and the potential removal of 30 acres of agricultural land for the creation of new wetlands in mitigation for the wetlands impacted by use of Site 20. It would also increase the cost of designing

Timely construction of the GRTA will require that RG&E use the two 345/115 kV transformers that have been ordered for Station 255 of the RARP, as well as a spare 345/115 kV transformer at Station 80. By re-deploying the RARP Station 255 transformers and a Station 80 spare transformer to Station 122, reconfiguring the 345 kV bus to solve stuck breaker issues (work that is nonetheless necessary), and increasing the ratings of some 34.5 kV and 11.5 kV lines, the term of a Ginna RSSA could be minimized.[2] This sequence of investments is a better solution to the issues faced by RG&E because it addresses the most urgent issue first (resolving the thermal overloads at Station 122), ensures reliability and capacity for growth in the long-term, and reduces costs for RG&E's customers.

The GRTA would include the following work:

A. Station 122 Upgrades:

RG&E will upgrade the three 345/115 kV transformers at STA 122 from 200 MVA-Class units to 400 MVA-Class units. In addition, a fault-duty short circuit study determined that RG&E must upgrade the 115 kV circuit breakers at Station 122 and one circuit breaker at Station 121. Due to constructability sequence constraints, new 115 kV Gas-Insulated Switchgear with 5 bays arranged in a breaker and half configuration will be installed to replace the 115 kV open-air configuration at Station 122.

B. 34.5 kV and 11.5 kV line Underground Transmission Lines:

With the new flow in the RG&E network, RG&E will uprate the following underground circuits:

1) 34.5 kV Circuit 718 between Station 29 and Station 1 (approximately 3.8 miles in length) to 972 amps summer normal and 1592 LTE.

2) 34.5 kV Circuit 735 between Station 81 and Station 7 (approximately 9.3 miles in length) to 664 amps summer normal and 867 LTE.

3) 34.5 kV Circuit 770 between Station 1 and Station 42 (approximately 2.3 miles in length) to 1202 amps summer LTE.

4) 11.5 kV Circuit 623 between Station 137 and Station 38 (approximately 1.4 miles in length) to 582 amps summer normal and 924 LTE.

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and constructing the RARP by $7-9 million, and might impact a possible $19-20 million office campus development that could create 1,000 jobs in the area.

[2] The project is in the pre-conceptual engineering phase, and may be impacted by the timing and requirements for regulatory approval, system and engineering studies which may have to be performed, outage availability, and third party agreements.

In addition, a fifth bay of 345 kV circuit breakers will be constructed at Station 80 to reconnect transformers #5 and #3. This will resolve loss of transformers #5 and #2 in a single contingency due to stuck breaker 2T8082, and loss of transformers #3 and #2 in a single contingency due to stuck breaker 1X8082. The fifth bay will have four circuit breakers, two of which will be between transformer #5 and transformer #3 terminal points

The GRTA addresses the most pressing need on RG&E's system and allows for the retirement of the Ginna facility. Even after the GRTA is put into service, however, other transmission work, including the RARP, will be needed to increase reliability as load grows in RG&E's service territory. RG&E proposes to complete the RARP in three phases, with the first phase being completed in 2019 and the final phase in 2021.[3]

Because RG&E will undertake work at Station 80 (which includes facilities certified by the Commission in the Rochester Transmission Project Article VII proceeding (Case 03-T-1385) and the RARP Article VII proceeding) and at Stations 7 and 121 (which also contain facilities approved in the Rochester Transmission Project proceeding), approvals of the Commission may be required. Work at Station 122 may require the approval of the Department of Environmental Conservation ("DEC") and other state and local agencies. Approval of the United States Army Corps of Engineers may also be required for some of the work referenced above. RG&E intends to request meetings as soon as possible with the Department of Public Service Staff, the DEC and other agencies and municipalities to explain the GRTA and discuss the necessary approvals.

RG&E needs to move forward quickly to complete the GRTA and thereby reduce the impact of a Ginna RSSA on RG&E's customers. RG&E anticipates filing petitions for the above-referenced approvals in the first quarter of 2015.

Respectfully submitted,

John D. Draghi

cc: Secretary Burgess
All Parties

[3] Phase I is the energization of Transformer 1 in Station 255 and Line 940. Phase II is the energization of Transformer 2 in Station 255 and Line 941. Phase 3 is the energization of Line 40. These phases are subject to change upon finding a more efficient sequence and discussions with third parties.

Rochester Area Reliability Strategy

Meeting Date: February 9, 2015

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Agenda

- Purpose of Meeting
- Executive Summary
- System Reliability Studies
- Update of *Ginna Retirement Transmission Alternative Project* (GRTA)
- Impact on *Rochester Area Reliability Project* (RARP)
- Regulatory Approvals
- Wrap-up

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Purpose of Meeting

- Explanation of the Ginna Retirement Transmission Alternative (GRTA) project
- Explanation of how GRTA will impact RARP
- Discuss regulatory requirements

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Executive Summary

1. RG&E received on April 23, 2013 a *Certificate of Environmental Compatibility and Public Need* for the Rochester Area Reliability Project (RARP). One purpose of RARP was to address a "long-term outage of Ginna generation."

2. Exelon said in a July 11, 2014 petition that it may permanently retire Ginna absent an RSSA with RG&E (14-E-0270). An RSSA would be expensive for RG&E's customers.

3. If Ginna is retired:
   - ✓ RG&E system would not meet reliability standards.
   - ✓ Station 122 transformers would be overloaded when the peak load reaches 1,430 MW. In 2014, the peak load was 1,508 MW.

4. RG&E issued a Request for Proposals (RFP) for solutions to the problem that would be created by the retirement of Ginna, and also evaluated transmission alternatives to an RSSA. RG&E identified a transmission solution that could shorten the term of the RSSA up to two years, provide net financial benefit to customers, and strengthen RG&E's system.

5. Transmission alternative lowers costs for customers.

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Executive Summary (continued)

6. Agreements that RG&E needs from the NYPSC regarding the development of the GRTA Project:
   - ✓ Confirmation that PSC approval is not required for work at Station 122
   - ✓ Confirmation that the PSC approval is not required for work on the underground 34.5 kV and 11.5 kV transmission lines
   - ✓ Confirmation that the 34.5 kV work at Station 7 does not require PSC approval
   - ✓ Confirmation that the new 345 kV Bay at Station 80 would be covered by a modification to EM&CP-I

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System Reliability Studies

RG&E analyzed the bulk power transmission system and transmission solutions to maintain system reliability.

The studies were conducted in accordance with the following reliability and design standards:

- ✓ North American Electric Reliability Corporation (NERC)
- ✓ Northeast Power Coordinating Council (NPCC)
- ✓ New York State Reliability Council (NYSRC)
- ✓ RG&E Transmission Planning Criteria

RG&E studied two different scenarios:

1. Temporary Loss of Ginna

2. Permanent Retirement of Ginna without RARP in Service

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System Reliability Studies (continued)

Scenario 1 – Temporary Loss of Ginna

A temporary loss of Ginna and any other important power system element, such as a transmission line or high-voltage transformer. This was considered as the worst N-1-1 contingency.

- ✓ The scenario did not examine the impact of a stuck breaker contingency, which would remove two transformers as a single contingency, because this was not required under the criteria at that time.
- ✓ The considered capacity of each transformer was higher than its nominal value, because the criteria of Long Term Emergency (LTE) rating was acceptable as the transformer capacity under emergency.

RARP was designed to solve the Scenario 1 reliability problems with a peak load at RG&E of 1,826 MW, which was forecasted for 2014. The current peak load has been 1,508 MW in the summer.

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System Reliability Studies (continued)

Scenario 2 – Permanent Ginna Retirement without RARP in service

Under normal transmission system conditions, the transformers at RG&E's bulk Station 122 would be overloaded whenever the RG&E peak load reaches 1,430 MW. The maximum acceptable capacity of each transformer, under normal condition, is its lower nominal value, instead of the LTE rating.

To resolve the immediate issues associated with the retirement of Ginna, **up to 1,859 MW**, the replacement and reconfiguration of the transformers at Station 122 and the uprating of several underground 11.5 kV and 34.5 kV transmission lines are required.

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Proposed Project - Overview

As outlined in RG&E's December 23, 2014 filing, **Ginna Retirement Transmission Alternative (GRTA)** will consist of the following components:

1. Reinforcements at Station 122: Replace three 345/115 kV transformers and reconfigure 345 kV bus:
   - ✓ Three new transformers 494/603/630 MVA
   - ✓ 345 kV bus reconfiguration to breaker and a half

2. Uprate 34.5 kV Circuits 718, 735, 770, and 11.5 kV Circuit 623

In addition, to meet reliability criteria put in place since the initiation of RARP, a new 345 kV Bay and additional work at Station 80 will eliminate the impacts of a "stuck breaker" scenario.

NYISO has completed a review of the ST122 scope and its expected impact on the NYS Transmission System. NYISO has determined that, pursuant to Section 2.4.2. of the NYISO Transmission Expansion and Interconnection Manual, a System Impact Study is not required for the ST122 work.

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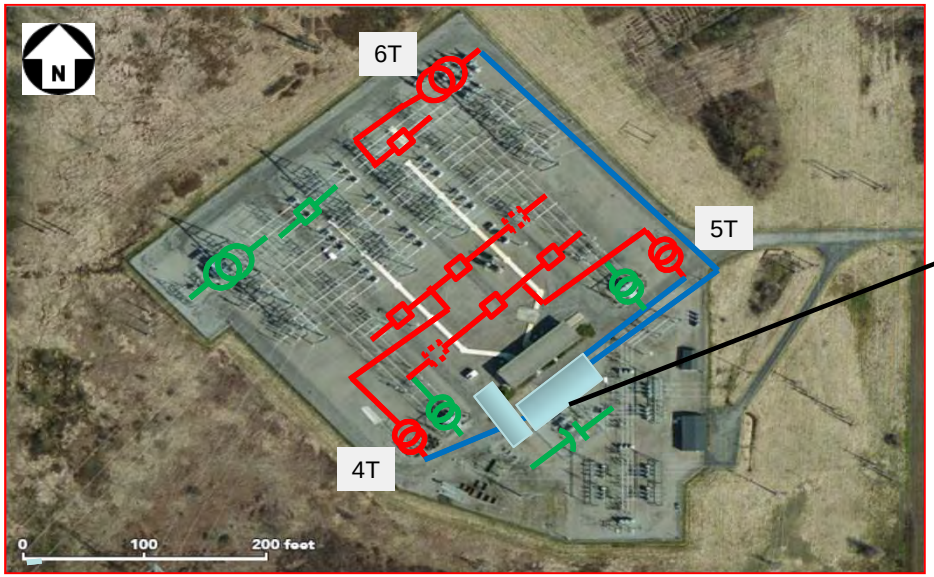
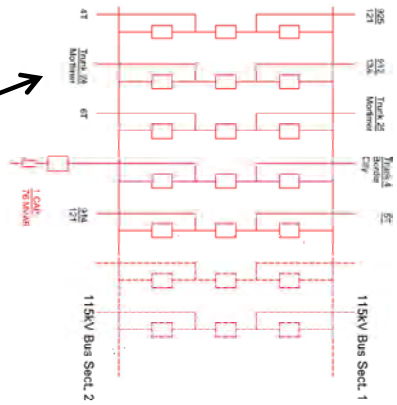
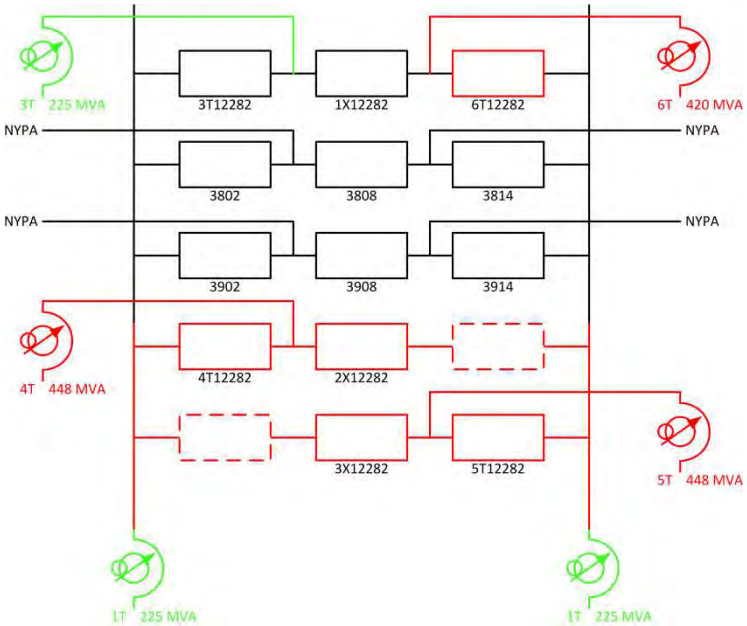
Station 122 – Overview of Work







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Station 122 – 345 kV Scope of Work

Installation of new Transformers and Appurtenances

- ✓ New 345 kV circuit breaker and 7 switches at 345 kV Bay 1
- ✓ New transformer 6T - 420 MVA 345/115 kV
- ✓ New transformer 5T - 448 MVA 345/115 kV
- ✓ New transformer 4T - 448 MVA 345/115 kV
- ✓ New location, foundation and oil containment for 4T, 5T, and 6T
- ✓ New cable connection on low side for 4T, 5T, and 6T
- ✓ New cable connection on high side of 4T, 5T, and 6T

Installation of new 345 kV Bays

- ✓ New 345 kV Bay No. 4, with 2 breakers and 7 switches
- ✓ New 345 kV Bay No. 5, with 2 breakers and 7 switches

345 kV General

- ✓ Update protection and control system, as necessary
- ✓ 345 kV Control Building Expansion

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Station 122 – 115 kV Scope of Work

Installation of new 115 kV Gas Insulated Switchgear (GIS)

- ✓ 15 local control cabinet relays
- ✓ 15 bay control relays
- ✓ New Control Building(s) to house GIS and appurtenant equipment
- ✓ New protection and control system for Circuits 914, 912, 925, and Trunk #4, Trunk #24, Trunk #25
- ✓ Remote end work at RG&E's Station 121
- ✓ Coordination with National Grid, as required, for remote end work at Mortimer and Border City Substations
- ✓ New protection and control system

115 kV General

- ✓ 115 kV connections from Transformers to GIS
- ✓ 115 kV connections from GIS to Line Terminal Structures
- ✓ Removal and demolition of existing 115 kV switchyard and control building
- ✓ 115 kV Transmission line terminal structure relocation or retrofit
- ✓ Relocate Circuit 925 from 3T low side to new 115 kV GIS
- ✓ Station service upgrade
- ✓ Grounding grid upgrade

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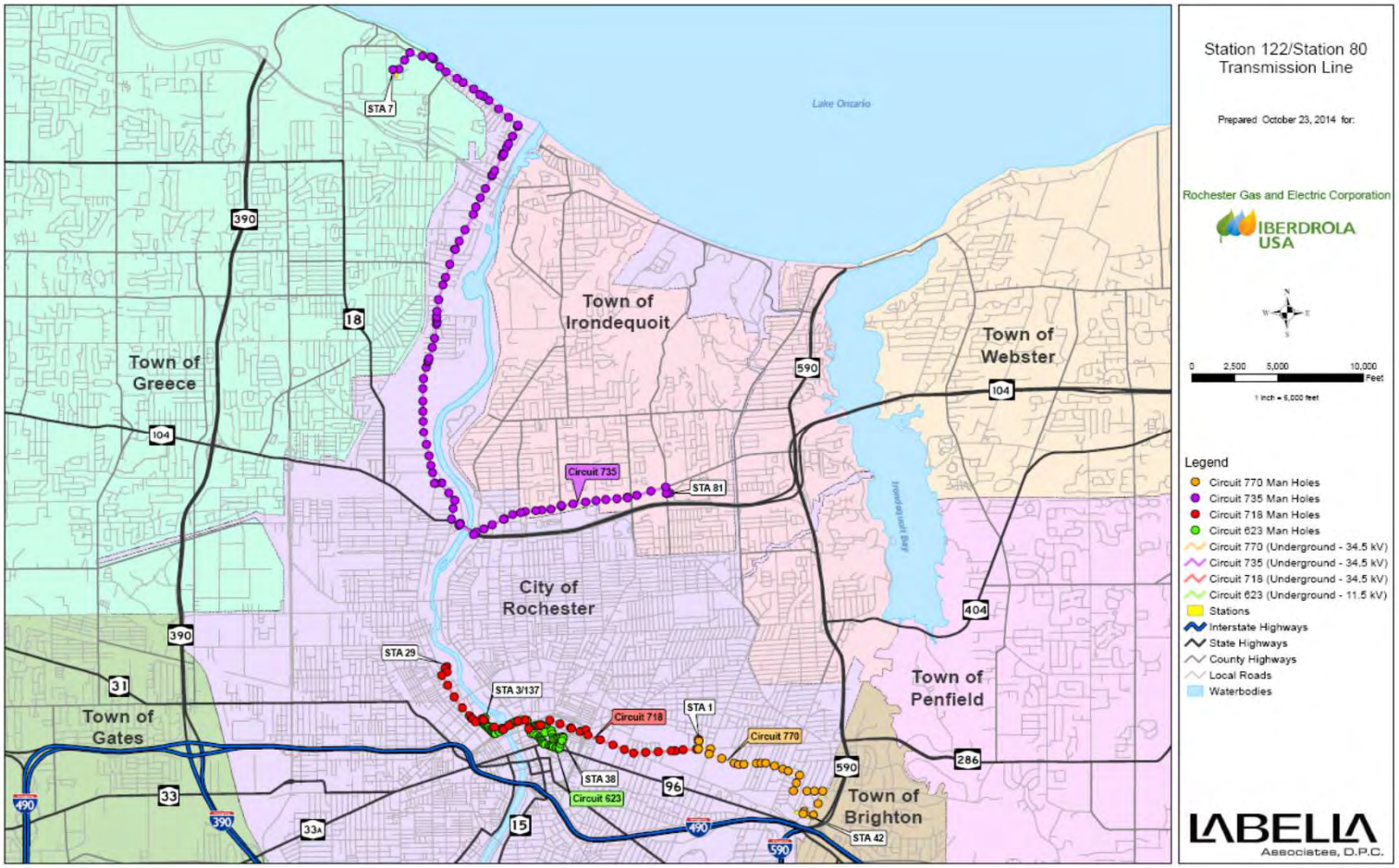
Transmission Lines - Overview of Work

Vast majority of Underground Transmission Lines are within the City of Rochester (population >125k). Underground work may require some new duct bank, and new or modified manholes. Vast majority of conductor is located and/or will be installed within existing public rights-of-way.



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Transmission Lines – Scope of Work

1. **Circuit 718 Uprate**
   - ✓ 34.5 kV underground circuit
   - ✓ 19,800± linear feet (3.8± linear miles) from Station 29 to Station 1

2. **Circuit 735 Uprate**
   - ✓ 34.5 kV underground circuit
   - ✓ 48,800± linear feet (9.2± linear miles) from Station 7 to Station 81

3. **Circuit 770 Uprate**
   - ✓ 34.5 kV underground circuit
   - ✓ 12,000± linear feet (2.3± linear miles) from Station 1 to Station 42

4. **Circuit 623 Uprate**
   - ✓ 11 kV underground circuit
   - ✓ 6,500± linear feet (1.2± linear miles) from Station 137 to Station 38

5. **At Remote End Stations**
   - ✓ Install new circuit breakers, switches, protection and control, ancillary equipment, and remove surge arresters, breakers, disconnect switches.

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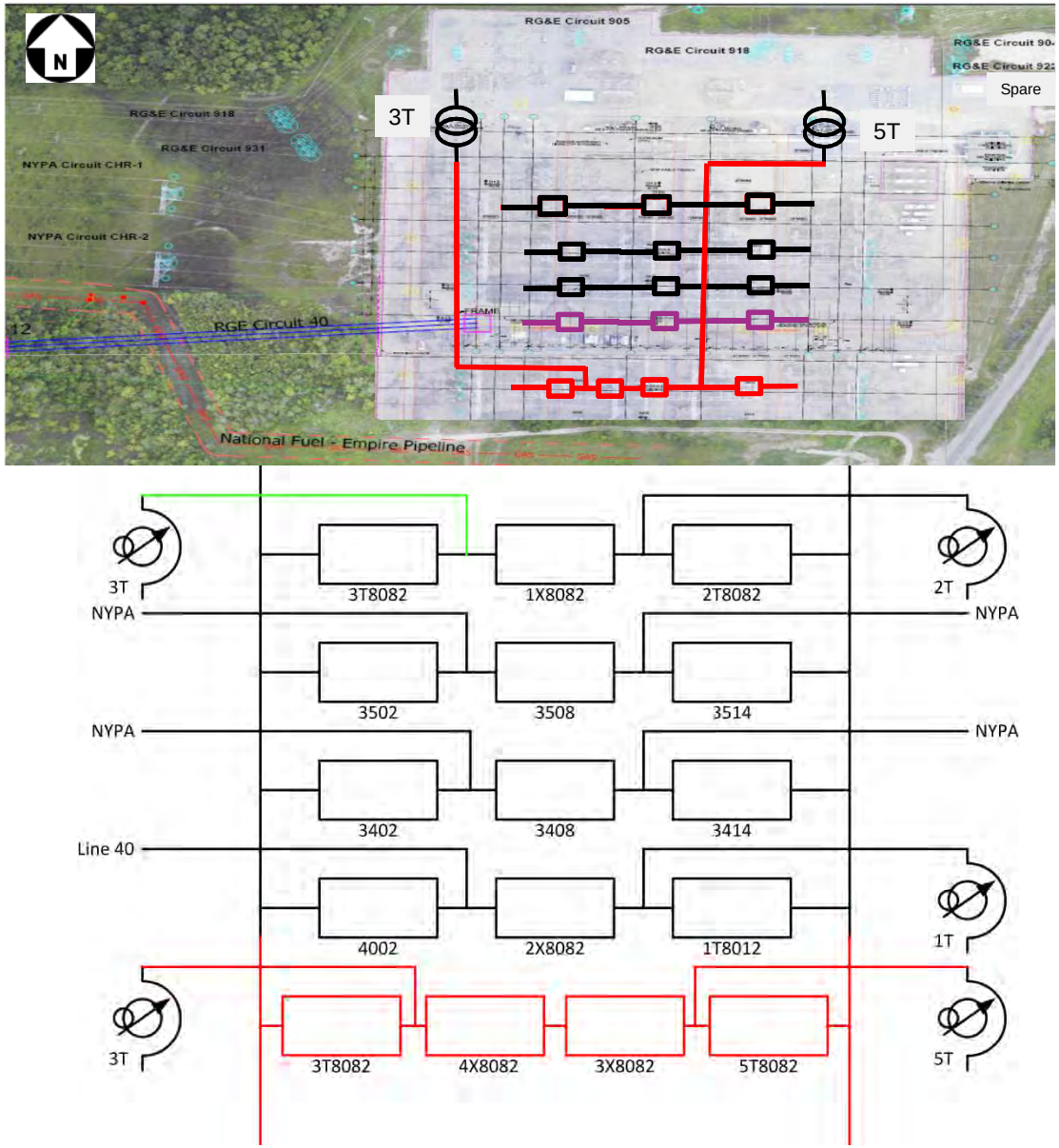
Station 80 - Overview of Work



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Station 80 – Scope of Work

1. **New 5th 345 kV Bay**
   - ✓ Relocate 5T terminal position to new 5th 345 kV bay
   - ✓ New circuit breakers, switches and ancillary equipment for 5T
   - ✓ New 345 kV connection between 345 kV Bay 5, Bus Sect. 2 and 5T
   - ✓ Relocate 3T terminal position to new 5th 345 kV bay
   - ✓ New circuit breakers, switches and ancillary equipment for 3T
   - ✓ New 345 kV connection between 345 kV Bay 5, Bus Sect. 1 and 3T
   - ✓ New 345 kV terminal, ancillary system and switch at 5T
   - ✓ New 345 kV terminal, ancillary system and switch at 3T
   - ✓ New integration and communication system
   - ✓ New or updated control and protection, as needed
   - ✓ Trench system expansion
   - ✓ New fence and internal roads
   - ✓ Expand station grounding system
   - ✓ Grading and station drainage system upgrades
   - ✓ Fence expansion approximately 100-ft to the south (w/in RG&E parcel). Coordinate w/ Empire Pipeline (south of Station).

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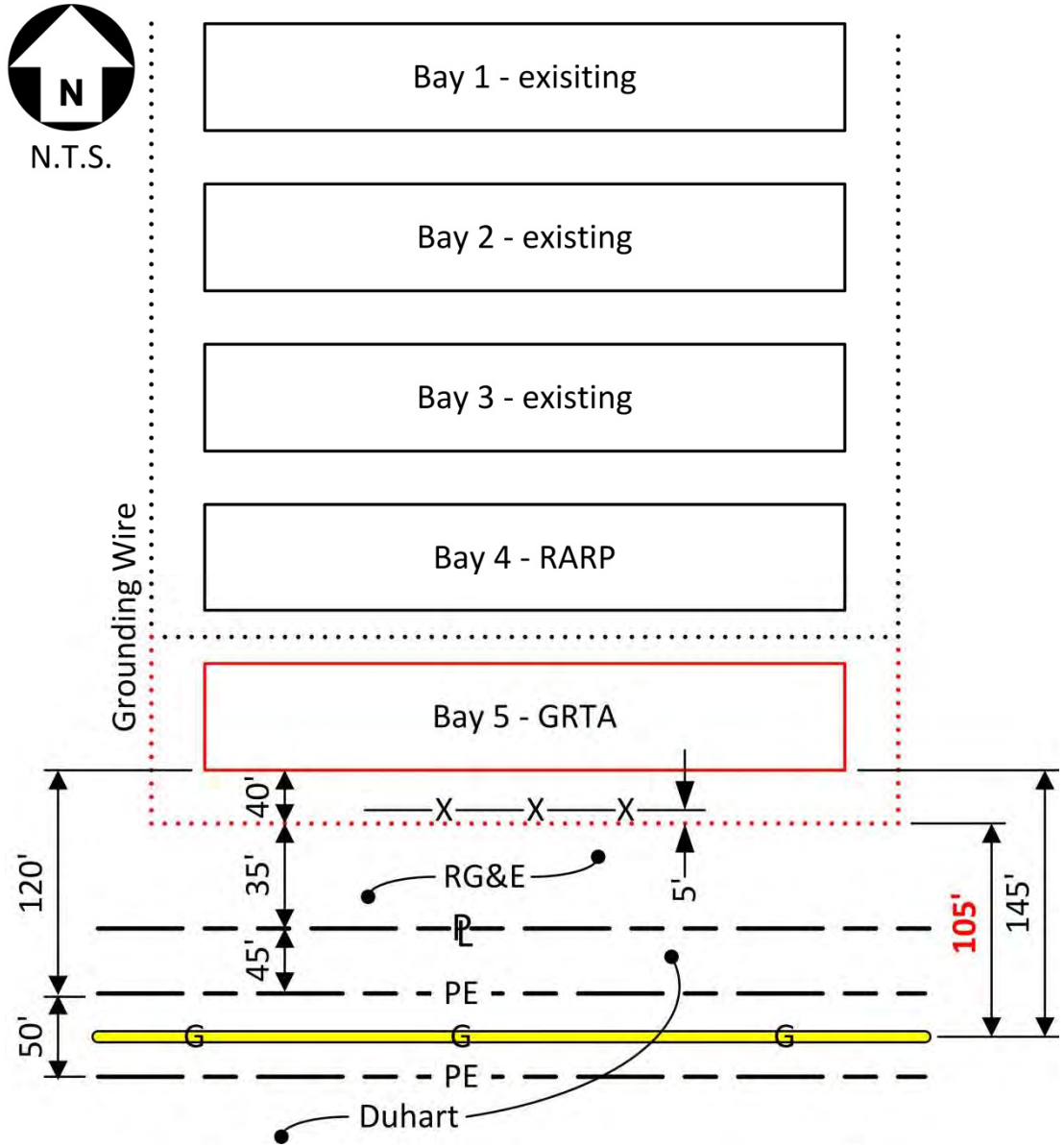
Station 80 – Empire Pipeline



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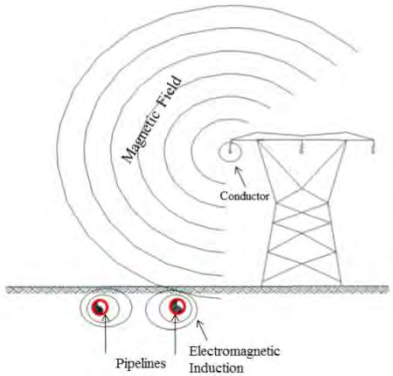
Station 80 – Empire Pipeline (continued)

1. **IEEE C2 2012 - 095 Method of Connection to Electrode**
   - ✓ "Made grounds or grounded structures should be separated by 10 feet or more from pipelines used for the transmission of flammable liquids or gases operating at high pressure (150 lb/in^2 or greater) unless they are electrically interconnected and cathodically protected as a single unit. Grounds within 10 feet of such pipelines should be avoided or shall be coordinated so that hazardous AC conditions will not exist and cathodic protection of the pipeline will not be nullified."
   - ✓ This means the separation between the extent of the grounding grid for the substation to the pipeline must exceed 10 feet.

2. **Empire Pipeline Encroachment Manual**
   - ✓ National Fuel's criteria is that no permanent structure or berm be placed within 25 feet of the pipeline. Permanent Easement creates separation.

IEEE separation requirements are exceeded by 10X.
Nat'l Fuel's separation requirements are exceeded by 4X.
Additionally RG&E is conducting an AC Mitigation Study.



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Permits

1. **Permits**
   - ✓ Federal
     - ➢ US Army Corps of Engineers (Amend §401 WQC, §404 wetlands) for work at Station 80, and (Section 9 and 10 of the Rivers and Harbors Act) for T-line work
   - ✓ State
     - ➢ NYSDPS – purpose of this meeting
     - ➢ NYSDEC (Article 24 wetlands, SPDES, SWPPP) primarily for work at Stations 80 and 122
     - ➢ State Historic Preservation Office
     - ➢ Department of Transportation – transmission line work in ROW
   - ✓ County
     - ➢ Department of Transportation – transmission line work in ROW
   - ✓ City
     - ➢ Bureau of Planning and Zoning Permits (SWPPP) – T-line work
     - ➢ Department of Environmental Services – T-line work in ROW
   - ✓ Town
     - ➢ Building Permit for Control Building at Station 122
     - ➢ Department of Public Works – T-line work in town road ROW

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Project Activities

1. **Station Tasks**
   - ✓ Conceptual engineering in progress
   - ✓ Detail engineering and GIS in Proposal phase
   - ✓ Use RARP equipment (2 ea. – transformers, breakers, switches), and spare transformer from Station 80 to reduce GRTA execution schedule. Updating technical requirements for replacement.
   - ✓ Stakeholders: reached out to NYPA, NYISO, National Grid

2. **Transmission Line Tasks**
   - ✓ Manhole condition assessment in progress
   - ✓ Conceptual engineering in progress
   - ✓ Detail engineering in Proposal phase
   - ✓ Stakeholders: reached out to City of Rochester

3. **ISD Milestones between December 2016 and June 2017**

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RARP Impacts

- ✓ GRTA mitigates immediate Need Date of RARP
- ✓ Construction at Station 80 (EM&CP-I) will continue without delay
- ✓ RARP's transmission line work (EM&CP-II) would commence no earlier than 4Q2015
- ✓ Final engineering and preparation of EM&CP-III will start in 2015 and continue through 2015 pending PSC decision on location of Station 255
- ✓ Coordinating outages with NYPA for 4th (RARP) and 5th (GRTA) Bays
- ✓ RARP would have multiple in-service dates for 345 kV and 115 kV circuits, the first estimated to start in 2019 and the last in 2020

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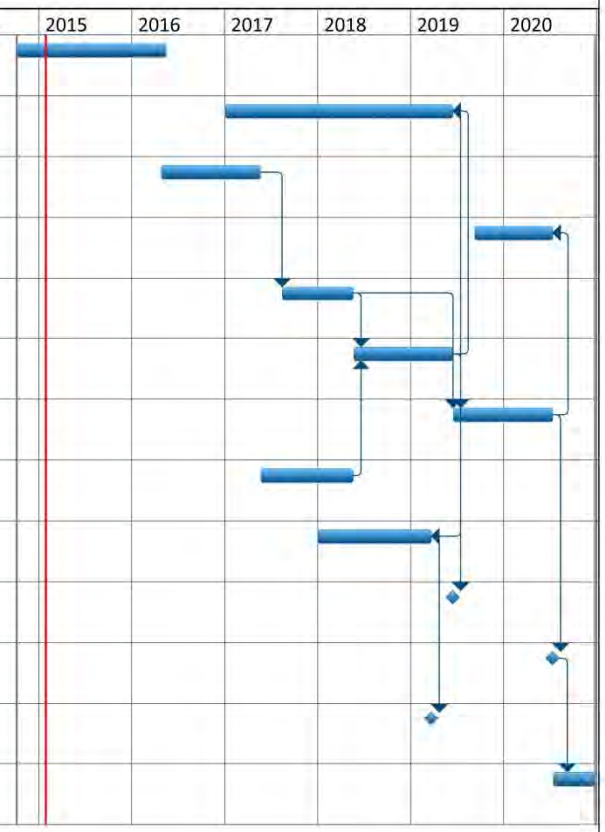
RARP – Tentative Revised Schedule

RG&E RARP Case 11-T-0534
Schedule Revised (January 2015)

ID	Task Name	Duration	Start	Finish
1	ST080 Construction (4th Bay Only)	21 mons	Mon 10/6/14	Fri 5/13/16
2	ST255 Construction/Commissioning	32 mons	Mon 1/2/17	Fri 6/14/19
3	ST418 Construction/Commissioning	14 mons	Mon 4/25/16	Fri 5/19/17
4	ST023 Construction/Commissioning	11 mons	Mon 9/9/19	Fri 7/10/20
5	Circuit 940 (ST067 to ST418)	10 mons	Mon 8/14/17	Fri 5/18/18
6	Circuits 940 & 941 (ST255 to ST067)	14 mons	Mon 5/21/18	Fri 6/14/19
7	Circuit 941 (ST067 to ST023)	14 mons	Mon 6/17/19	Fri 7/10/20
8	Circuit 906 Relocation	13 mons	Mon 5/22/17	Fri 5/18/18
9	Circuit 40 (ST255 to ST080)	16 mons	Mon 1/1/18	Fri 3/22/19
10	T1/Circuit 940 ISD	0 days	Fri 6/14/19	Fri 6/14/19
11	T2/Circuit 941 ISD	0 days	Fri 7/10/20	Fri 7/10/20
12	Circuit 40 ISD	0 days	Fri 3/22/19	Fri 3/22/19
13	Close out	6 mons	Mon 7/13/20	Fri 12/25/20



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Regulatory Approvals

1. Existing underground 11 kV transmission circuit (623) and underground 34.5 kV transmission circuits (718, 735, 770) are under the threshold for inclusion in an Article VII project by virtue of:

   - ✓ their voltage (11 kV and 34.5 kV per §85-2.1(e)(1))
   - ✓ location/configuration (underground in a city with a population of greater than 125,000 per §85-2.1(e)(2))

2. Existing remote-end stations (1, 29, 38, 42, 81, 122, 137) were not prior Article VII projects

3. No material increase in any environmental impact to facilities constructed under RARP (Case No. 11-T-0534, certificate issued April 23, 2013) or RTP (Case No. 03-T-1385, certificate issued December 16, 2004)

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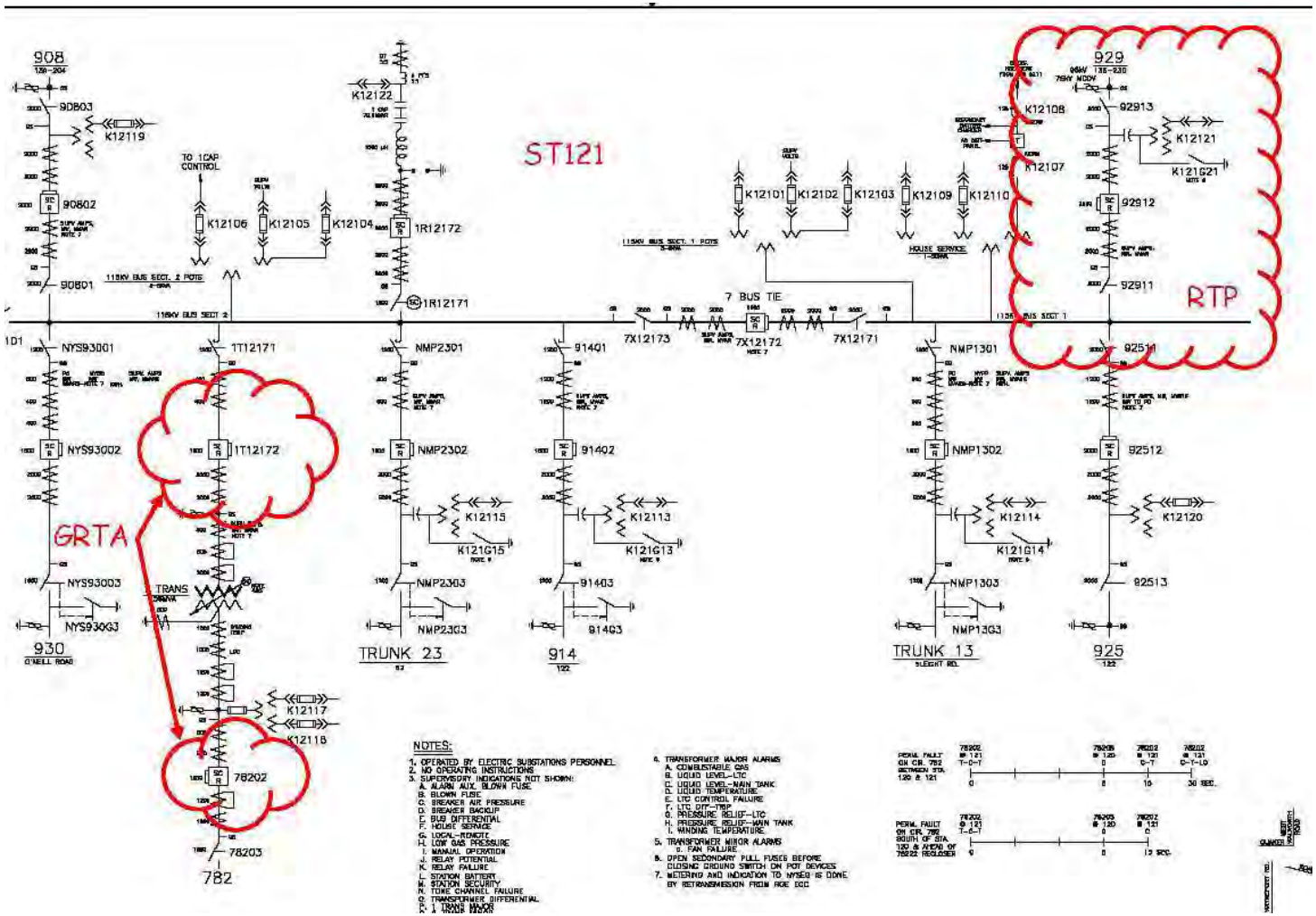
Regulatory Approvals (continued)

3a. Upgrades at Station 121 (original construction pre-dates Article VII) are on Circuit 782 which was not part of RTP (Circuit 929)



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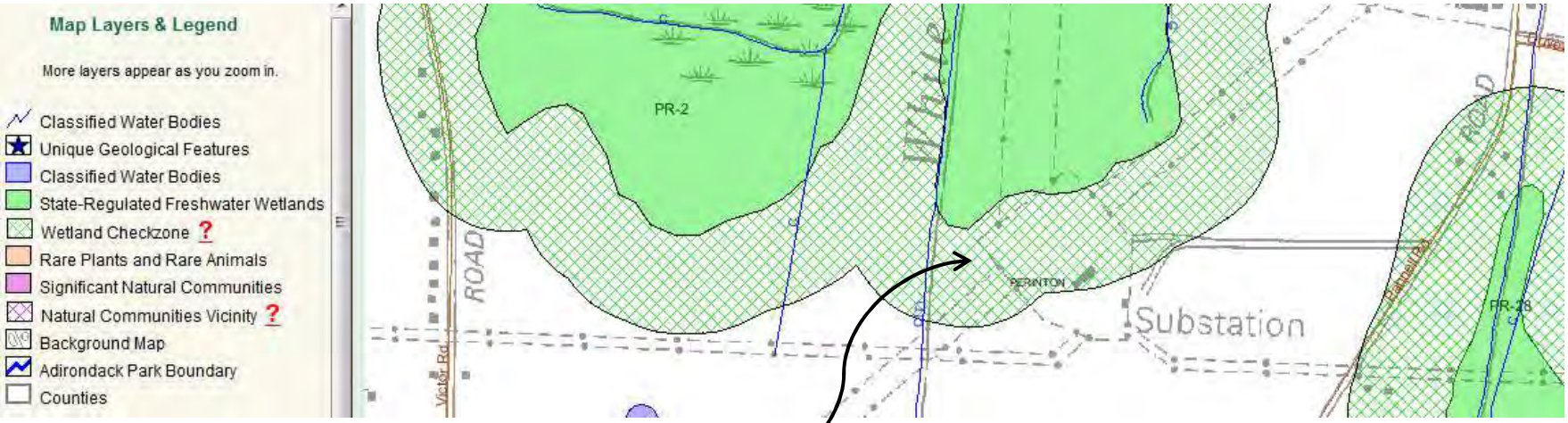
Regulatory Approvals (continued)

3b. Work at Station 122 (original construction pre-dates Article VII), all within the existing site fence line, but adjacent to NYSDEC jurisdictional wetland

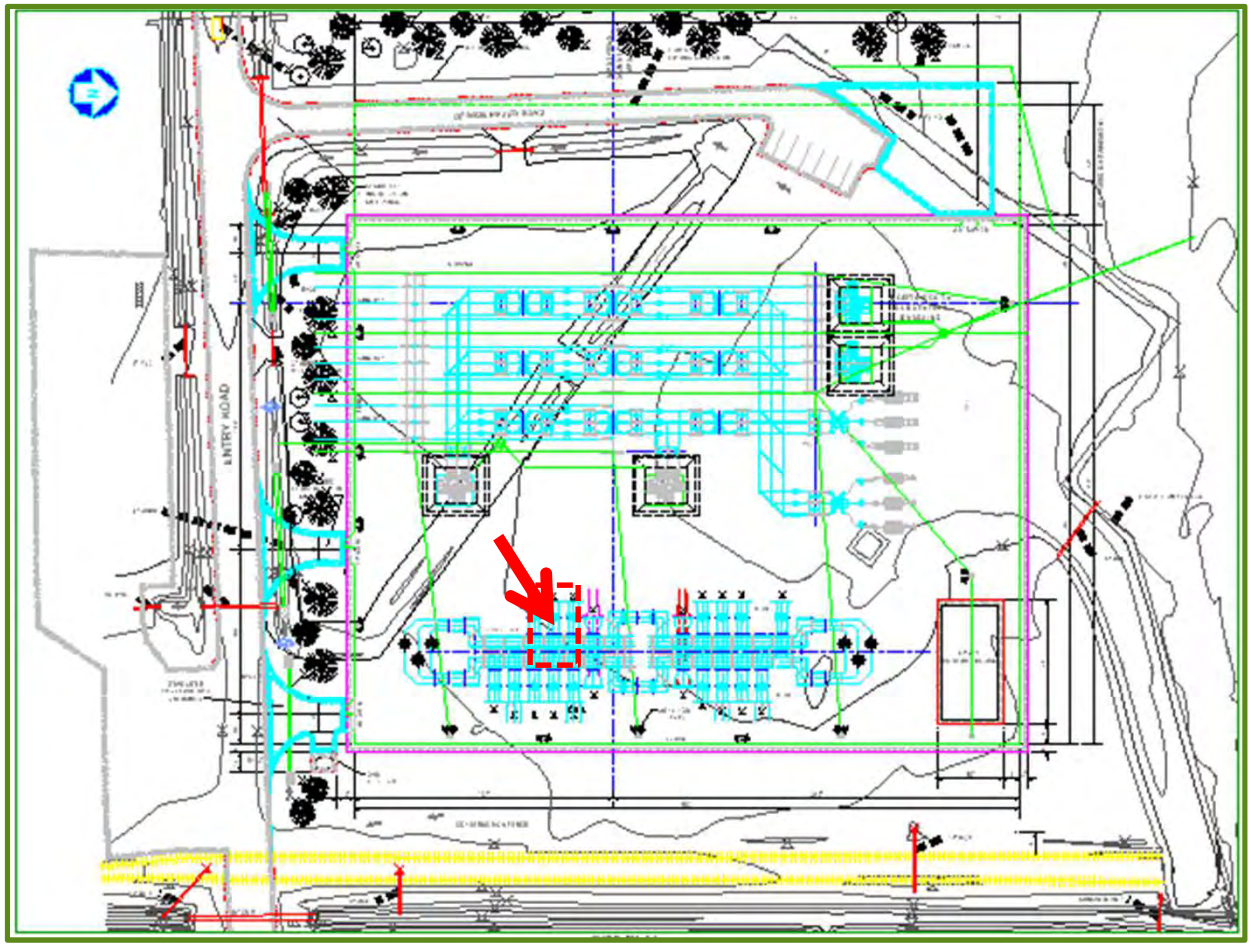


Note: the "check zone" is an area around the mapped wetland and is not the wetland or the regulated 100-foot buffer zone.

For Discussion Purposes Only

Regulatory Approvals (continued)

3c. Upgrades to one breaker and two switches on 34.5 kV side of Station 7 (RTP) are within the existing site fence line, and have an environmental impact of 0.00 (zero) acres



For Discussion Purposes Only

Regulatory Approvals (continued)

4. Proposed 5th Bay at Station 80 (original construction pre-dates Article VII) requires an expansion of approximately 2.01 acres on previously disturbed land, which will result in the loss of one wetland that is approximately 0.37 acres

For Discussion Purposes Only

Wrap-up

1. Additional Questions?

2. Action Items

3. Path Forward / Timeline

For Discussion Purposes Only

ENGINEERING &
TECHNICAL SERVICES, INC.

AC INTERFERENCE ANALYSIS

STATION 80 5th BAY EXPANSION

ROCHESTER GAS & ELECTRIC COMPANY

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Revision 1

EXECUTIVE SUMMARY

This report summarizes the results of an AC interference analysis for Rochester Gas & Electric Company (RG&E) on the Station 80 5th Bay expansion project and the effects it may have on the existing 24" Empire pipeline. This pipeline may be subject to additional AC electrical interference effects as a result of this expansion project. Previous AC interference analysis and mitigation system design for the 24" Empire pipeline as a result of the eight (8) RG&E electric transmission circuits and two (2) New York Power Authority (NYPA) which parallel and cross the pipeline was completed by ARK Engineering in 2006. The pipeline and station expansion under study is located in Monroe County, New York.

This final report presents the predicted additional AC interference pipeline potentials as a result of the Station 80 expansion project during peak load conditions on the eight (8) RG&E electric transmission circuits and two (2) NYPA electric transmission circuits. Fault conditions on these circuits were also simulated to determine any additional AC inductive and conductive coupling effects on this pipeline as a result of this station expansion project.

The results of this study indicate that any additional interference effects to the pipeline as a result of the Station 80 5th Bay expansion will not increase the AC steady state interference voltage levels above the design limit of fifteen (15) Volts along this pipeline in this area.

For the pipeline section under study in the area of the Station 80 5th Bay expansion work, an additional maximum computed induced AC pipeline potential of approximately five and one half (5.5) Volts, with respect to remote earth, occurs at GPS coordinate 43.053811° N, 77.694916° W. At this location, the pipeline parallels two (2) NYPA electric transmission circuits and one (1) RG&E (Future circuit 40) electric transmission circuit.

During simulated single phase-to-ground fault conditions on the electric transmission circuits, the maximum total pipeline coating stress voltage level was computed. This is the sum of the inductive and conductive AC interference effects on the pipeline, including the existing AC mitigation system installed along the Empire pipeline in this area.

The maximum pipeline coating stress voltage was calculated at three thousand six hundred seventy (3,670) Volts. This value was calculated at GPS coordinate 43.053811° N, 77.694916° W. This peak voltage is the result of a simulated fault on the 345 kV NYPA CHR-1 electric transmission circuit that parallels the pipeline at this location.

This coating stress voltage level is still below the design limit of five thousand (5,000) Volts.

AC current density calculations associated with AC corrosion mechanisms were computed using pipeline touch voltages. A peak AC density of approximately thirty-four (34) A/m^2 was calculated at GPS coordinate 43.053318° N, 77.649478° W. At this location, the pipeline parallels two (2) NYPA electric transmission circuits and one (1) RG&E electric transmission circuit (future circuit 40). .

Based upon this analysis, no additional AC mitigation is recommended for this pipeline in the area of the Station 80 5th Bay expansion project.

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&
MITIGATION SYSTEM DESIGN

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APPENDIX B – Pipeline Steady State, AC Current Density, & Fault Plots

- Steady State Induced
- AC Current Density
- Fault – Coating Stress Voltages
- Fault – Touch and Step Voltages

APPENDIX C – Power & Pipeline Company Data

1 INTRODUCTION

1.0 INTRODUCTION

ARK Engineering & Technical Services, Inc. was contracted by Rochester Gas & Electric Company (RG&E) to investigate any additional AC electrical interference effects on the existing National Fuel Gas Company 24" Empire State pipeline, as a result of the expansion of Station 80 electrical substation. Previous AC interference analysis and mitigation system design for the 24" Empire pipeline as a result of the eight (8) RG&E electric transmission circuits and two (2) New York Power Authority (NYPA) electric transmission circuits which parallel and cross the pipeline was completed by ARK Engineering in 2006. This station expansion project is located in Monroe County, New York.

This report presents the computed additional steady state induced AC pipeline potentials as a result of the Station 80 expansion work. Simulated fault conditions on the electric transmission circuits were also modeled to determine the extent of additional pipeline coating stress voltages effects from the substation expansion.

The conclusions in this report are based upon field data, pipeline data provided by National Fuel Gas Company, electric transmission circuit data provided by RG&E, and previous modeling and analysis performed by ARK Engineering on the Empire pipeline in the area of Station 80 .

Calculations and analysis were performed using CDEGS state-of-the-art modeling software by SES (Safe Engineering Services and Technologies, Ltd).

1.1 JOINT FACILITY CORRIDOR OVERVIEW

This pipeline is located in Monroe County, New York. All GPS coordinates in this report are based upon information provided by National Fuel Gas Company and Google Earth files created by ARK Engineering from the previous AC interference analysis work completed on the Empire pipeline.

The areas of concern near the Station 80 expansion project where the pipeline parallels or crosses the eight (8) RG&E electric transmission circuits and two (2) NYPA electric transmission circuits and the approximate pipeline station numbers are outlined below:

- From approximate GPS coordinate 43.053534° N, 77.709338° W to 43.053515° N, 77.683682° W, the pipeline parallels three (3) RG&E electric transmission circuits.

- From approximate GPS coordinate 43.053515° N, 77.683682° W to 43.053181° N, 77.673229° W, the pipeline parallels five (5) RG&E electric transmission circuits.

- From approximate GPS coordinate 43.053299° N, 77.671909° W and continuing east, the pipeline parallels two (2) RG&E electric transmission circuits.

- From Station 80 continuing north, three (3) RG&E electric transmission circuits do not cross or parallel the pipeline but are in proximity and were considered in this study.

When metallic pipelines are located in shared rights-of-way with high voltage electric transmission circuits, the pipelines can incur high induced voltages and currents due to AC interference effects. This situation can cause a number of safety issues if not mitigated effectively. The possible effects of this AC interference can include: personnel subject to electric shock up to a lethal level, accelerated corrosion, arcing through pipeline coating, arcing across insulators, disbondment or degradation of coating, or possibly perforation of the pipeline.

AC interference simulation programs were used as part of this project to model the right-of-way (ROW) and estimate the levels of induced and conductive AC voltage on the pipeline.

1.2 OBJECTIVES & PROJECT TASKS

The primary objectives of this study were as follows:

1.2.1 Determine any additional AC electrical interference effects to the pipeline during steady state and fault conditions on the ten (10) electric transmission circuits based upon the expansion of the Station 80 site.

1.2.2 If required, recommend additional AC mitigation methods to reduce any additional induced steady state AC pipeline potentials and touch voltages to less than 15 Volts at all locations on the pipeline.

1.2.3 If required, recommend additional mitigation methods to reduce any additional fault-induced coating-stress voltages on the pipeline to less than 5,000 Volts, for protection of the pipeline coating.

1.2.4 If required, recommend additional mitigation methods for aboveground pipeline locations, such as regulator stations.

1.2.5 Assess the induced AC density on the pipeline for the potential threat of AC corrosion effects.

1.2.6 Perform calculations to determine the likelihood of AC corrosion effects to this pipeline.

1.2.7 If AC corrosion effects are likely, based upon these calculations, determine if additional mitigation is required to reduce or eliminate the likelihood of AC corrosion effects.

The project tasks associated with this portion of the AC interference analysis and mitigation study consist of the following:

1.2.8 Soil Resistivity Analysis - Soil Resistivity measurements were taken along the pipeline route, during the previous AC interference analysis on the Empire pipeline. An equivalent multi-layer soil model was obtained from these measurements using the modeling software. This model was then applied to subsequent simulation steps. This task is described in Chapter 2, and detailed results are presented in Appendix A.

1.2.9 Inductive Interference Analysis - Circuit models for the pipeline and electric circuits were developed and used to determine additional magnetically induced pipeline potentials during steady state and fault conditions on the electric transmission circuits, as a result of the Station 80 expansion. This task is described in Chapter 3, and detailed results are presented in Appendix B.

1.3.0 Conductive Interference Analysis - The effects of single line-to-ground faults of nearby electric transmission circuits on the pipeline in proximity was studied. These results were used to calculate any additional coating-stress voltages along the pipeline. This task is described in Chapter 3, and detailed results are presented in Appendix B.

1.3 A BRIEF PERSPECTIVE ON ELECTROMAGNETIC INTERFERENCE MECHANISMS

The flow of energy transmitted by electric power is not totally confined within the power conductors. However, the spatial density of energy in the environment surrounding these circuits decreases sharply with an increase in distance from the conductors. Metallic conductors such as pipelines that are located near electric transmission circuits may capture a portion of the energy encompassed by the conductors' paths, particularly under unfavorable circumstances such as long parallel exposures and fault conditions. In such cases, high currents and voltages may develop along the conductors' lengths. Energy may also flow directly from power installations to pipeline installations via conductive paths common to both.

The electromagnetic interference mechanisms at low frequencies have been traditionally divided into three (3) categories: capacitive, inductive and conductive coupling. These categories and their possible effects are illustrated in Figure 1-1.

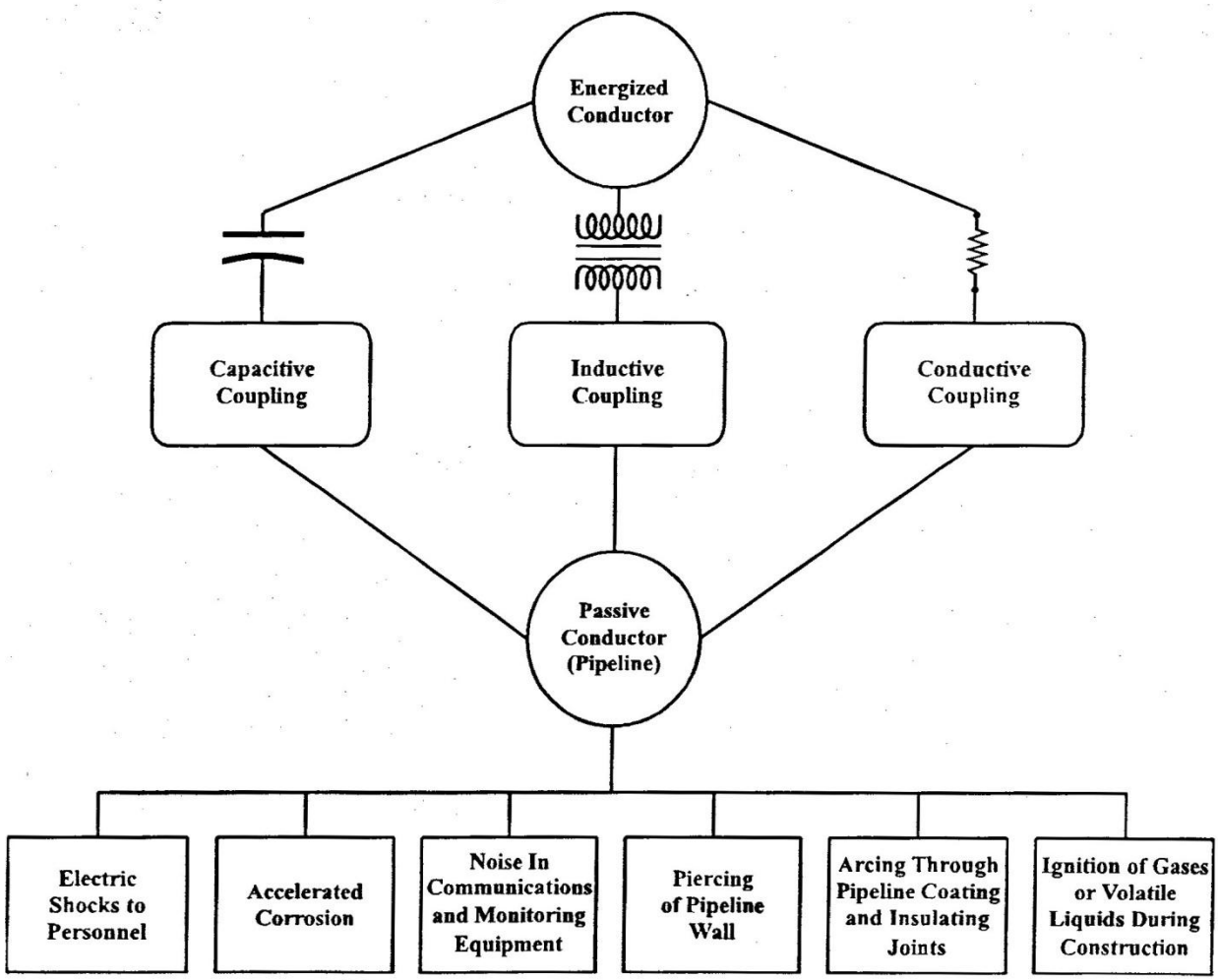

Figure 1-1: Interference Mechanisms and Effects on Pipeline

1.3.1 Capacitive Coupling

Mechanism:

Electrostatic or capacitive coupling results from the electric field gradient established between energized transmission line conductors and the earth. When the transmission line voltage is very high, a significant electric field gradient exists in the neighborhood of the transmission line. Large conductors, which are near and parallel to the transmission line and insulated from the earth, are liable to accumulate a significant electric charge, which represents a very real danger for personnel. Typically, such conductors include: equipment isolated from the earth, vehicles with rubber tires, aboveground pipelines, or pipelines under construction in dry areas when no precautions have been taken to establish adequate grounding for the pipeline lengths not yet installed in the ground. Hazards range from slight nuisance shocks to ignition of nearby volatile liquids with the accompanying risk of explosion, or electrocution of personnel.

Mitigation Measures:

Buried pipelines are relatively immune to interference due to capacitive coupling because, despite even an excellent coating, the length of exposure to the surrounding soil makes for an adequate ground to dissipate any significant charge that might otherwise accumulate. Aboveground pipelines, including pipelines under construction (which may or may not be buried in part) do not naturally have this protection**.** One means of protection is periodic grounding to earth, via ground rods, or other ground conductors judiciously placed so as to be unaffected by ground currents emanating from nearby towers during a fault.

1.3.2 Inductive Coupling

Mechanism:

Electromagnetic or inductive interference in a passive conductor (pipeline) results from an alternating current in another energized conductor (power line), which is more or less parallel to the first. This level of interference increases with decreasing separation and angle between the conductors, as well as with increasing current magnitude and frequency in the energized conductor. The combination of a high soil resistivity and passive conductors with good electrical characteristics (good coating, high conductivity and low permeability) also result in high-induced currents.

Peak potential values occur at discontinuities in either the energized or the passive conductor. When a transmission line and a pipeline are interacting, such discontinuities take the form of rapid changes in separation between the pipeline and transmission line, termination of the pipeline or an insulating junction in the pipeline (which amounts to the same thing), sudden changes in pipeline coating characteristics, a junction between two (2) or more pipelines or transposition of transmission line phases. Note that the induction effects on pipelines during normal power line operating conditions are small compared to the induction effects experienced by a pipeline during a power line fault. The most severe kind of fault is a single-phase-to-ground fault during which high currents circulate in one of the power line phases and are not attenuated by any similar currents in other phases. Hence, mitigation methods, which suffice for single-phase fault conditions, are often adequate for other conditions. It must be noted however, that the longer duration of the resulting potentials in the pipeline during steady state conditions makes the problem important to investigate from a perspective of human safety.

Unlike conductive interference, which tends to be a rather local phenomenon, inductive interference acts upon the entire length of the pipeline that is near to the power lines. Note, however, that conductive interference can involve long sections of a pipeline if several towers adjacent to the faulted tower discharge a significant portion of the fault current, or if a ground conductor connected to the pipeline (anode) and located near a faulted tower, picks up current from the soil.

The large potentials induced onto a pipeline during a fault can destroy insulated junctions, pierce holes in lengths of coating, and puncture pipeline walls. Equipment electrically connected to the pipeline, such as cathodic protection devices,

communications equipment, and monitoring equipment can be damaged, and personnel exposed to metallic surfaces, which are continuous with the pipeline, can experience electrical shocks. Accelerated corrosion is another possible result. Implementing appropriate mitigative measures, as discussed below, can prevent this situation.

Although a pipeline equipped with mitigative measures appropriate to deal with phase-to-ground faults does not usually present a great safety hazard during normal conditions, several problems can still exist due to low magnitude induced alternating currents. Accelerated corrosion of steel can result if not offset by increased cathodic protection. This may mean a shortened life for sacrificial and impressed current anode beds. Small amounts of AC can also render impractical the use of a pipeline as a communication channel for data such as pressure and temperature readings to pumping and compressor stations.

Mitigation Measures:

Pipeline Coating Resistance - The coating resistance of the pipeline should be chosen as low as corrosion considerations permit. Pipeline coating resistance plays an important role in determining pipeline potentials during a fault condition. During a fault condition, on an electric transmission circuit, the pipeline coating conducts significant amounts of current and should be regarded more as a poor grounding system than an insulator. When this perspective is assumed, it is seen that lowering pipeline coating resistance and bonding grounded conductors to the pipeline steel are two (2) applications of the same principle.

Pipeline Section Length - In theory, the potential induced electromagnetically in a pipeline section insulated at both ends is roughly proportional to the length of the exposed region. When this relationship no longer holds, the pipeline is said to have exceeded its characteristic length. The maximum potential value in a section (with respect to remote ground) occurs at each extremity with roughly the same magnitude and opposite phase. This means that each insulating junction is subjected to a stress voltage that is double the peak value in the section. If insulating junctions are inserted frequently enough along a pipeline, then the section size is kept to a minimum, and consequently, so are the peak voltages in the pipeline. This constitutes one possible mitigation method. However, this thorough segmentation can result in very high construction and pipeline cathodic protection costs.

Grounding - Grounding of a pipeline, as a protection against the significant voltages that appear during an electrical fault condition, is one of the most effective mitigation measures available. A pipeline should be grounded at appropriate locations throughout its length. Typical grounding locations include: all termination points, both extremities of a segment which is grounded at both ends by an insulating junction, just before and just after a pipeline crosses a power line at a shallow angle, and any other important point of discontinuity likely to result in high induced voltages during a fault condition. Such points include locations where the passive conductor:

- Suddenly veers away from the power line.
- Suddenly changes coating characteristics.

- Emerges from the earth, or returns to the earth.

Other locations where high-induced voltages are likely include points where power line phases are transposed and points where two (2) or more pipelines meet.

In order not to load cathodic protection installations significantly, grounds should be made of an adequate sacrificial material such as zinc or should be made via solid-state-isolator or polarization cells. These solid state decoupling devices (SSD) should be properly sized, spaced and physically secured to withstand the current resulting during a power line fault. Caution should be taken to locate grounds far enough away from any nearby power line structure, so that the soil potential near the ground does not rise to undesirable values during a power line fault condition. Soil potentials drop off rather quickly around a faulted structure injecting currents into the earth, so this is not an extremely difficult proposition.

Buried Mitigation Systems - A highly effective means of mitigating excessive AC pipeline potentials is the installation of gradient control wires or matting. These methods reduce both inductive and conductive interference. These gradient control wires consist of one or more bare conductors which are buried parallel and near to the pipeline and which are regularly connected to the pipeline. These wires provide grounding for the pipeline and thus lower the absolute value of the pipeline potential (i.e., the potential with respect to remote earth). They also raise earth potentials in the vicinity of the pipeline such that the difference in potential between the pipeline and local earth is reduced. As a result, touch voltages are significantly reduced.

1.3.3 Conductive Coupling

Mechanism:

When a single-phase-to-ground fault occurs at a power line structure, the structure injects a large magnitude current into the earth raising soil potentials in the vicinity of the structure. If a pipeline is located near such a faulted structure, then the earth around the pipeline will be at a relatively high potential with respect to the pipeline potential. The pipeline potential will typically remain relatively low, especially if the pipeline coating has a high resistance. The difference in potential between the pipeline metal and the earth surface above the pipeline is the touch voltage to which a person would be subjected when standing near the pipeline and touching an exposed metallic appurtenance of the pipeline.

If the pipeline is perpendicular to the power line, then no induction will occur and the conductive component described above will constitute the entirety of the touch voltages and coating stress voltages appearing on the pipeline. If the pipeline is not perpendicular to the power line, then an induced potential peak will appear in the pipeline near the fault location. Based on previous interference studies, the induced potential peak in the pipeline is typically on the order of one hundred and fifty-five degrees (155°) out of phase with the potential of the faulted structure and therefore with the potentials of the soil energized by the structure. Thus, the pipeline steel potential due to induction is essentially opposite in sign to the soil potentials due to conduction. Therefore, inductive and conductive effects reinforce each other in terms of coating stress voltages and touch

voltages.

Mitigation Measures:

The magnitude of the conductive interference is primarily a function of the following factors:

i) GPR of Transmission Line Structure. Soil potentials and touch voltages due to conductive coupling are directly proportional to the ground potential rise (GPR) of the transmission line structure. This GPR value is a property of the entire transmission line system.

ii) Separation Distance. Although soil potentials and therefore touch voltages obviously decrease with increasing distance away from the faulted structure, the rate of decrease varies considerably from site to site, depending upon the soil structure, as described below.

iii) Size of Structure Grounding System. Soil potentials decrease much more sharply with increasing distance away from a small grounding system than that from a large grounding system. Conductive interference can be minimized by limiting the use of counterpoise conductors and ground rods, by the power company, at sites where pipelines are in close proximity to the electric transmission system structures.

iv) Soil Structure. When the soil in which the structure grounding system is buried has a significantly higher resistivity than the deeper soil layers (particularly if the lower resistivity layers are not far below the structure grounding system), earth surface potentials decay relatively sharply with increasing distance away from the structure. When the inverse is true, i.e., when the structure grounding system is in low resistivity soil, which is under laid by higher resistivity layers, earth surface potentials may decay very slowly.

v) Pipeline Coating Resistance. When a pipeline has a low ground resistance (e.g., due to coating deterioration over time), the pipeline collects a significant amount of current from the surrounding soil and rises in potential. At the same time, earth surface potentials in the vicinity of the pipeline decrease due to the influence of the pipeline. As a result, the potential difference between the pipeline and the earth surface can be significantly reduced.

When a conductive interference problem is present, touch voltages can be reduced by: either reducing earth surface potentials in the vicinity of the pipeline, raising the pipeline potentials near the faulted structure, or a combination of these two (2) actions. The most effective mitigation systems perform both of these actions.

1.4 A BRIEF PERSPECTIVE ON AC CORROSION MECHANISMS

1.4.1 AC Corrosion Mechanism

AC corrosion is the metal loss that occurs from AC current leaving a metallic pipeline at a coating holiday. The mechanism of AC corrosion occurs when AC current leaves the pipeline through a small holiday in low resistance soil conditions.

1.4.2 Mitigation of AC Corrosion

The main factors that influence the AC corrosion phenomena are:

- Induced AC pipeline voltage
- DC polarization of the pipeline
- Size of coating faults (holidays)
- Local soil resistivity at pipe depth

The induced AC pipeline voltage is considered the most important parameter when evaluating the likelihood of AC corrosion on a buried pipeline section.

The likelihood of AC corrosion can be reduced through mitigation of the induced AC pipeline voltage. The European Standard CEN/TS 15280:2006 "Evaluation of AC Corrosion Likelihood of Buried Pipelines - Application to Cathodically Protected Pipelines" recommends that AC pipeline voltages should not exceed the following:

- Ten (10) Volts where the local soil resistivity is greater than 25 ohm-meters.
- Four (4) Volts where the local soil resistivity is less than 25 ohm-meters.

These AC pipeline voltage limits are derived in part by calculating AC density at pipeline coating holidays. Since the AC current is mainly discharged to earth through the exposed steel at pipeline coating holidays, the AC corrosion rate can vary proportionately with increasing AC density at a coating holiday.

European Standard CEN/TS 15280, offers the following guidelines:
The pipeline is considered protected from AC corrosion if the root mean square (RMS) AC density is lower than 30 A/m^2. In practice, the evaluation of AC corrosion likelihood is done on a broader basis:

- Current density lower than 30 A/m^2: no or low likelihood of AC Corrosion effects
- Current density between 30 and 100 A/m^2: medium likelihood of AC Corrosion
- Current density higher than 100 A/m^2: very high likelihood of AC Corrosion

If the soil resistivity and the pipeline AC voltage are known, the risk of AC corrosion can be determined using the following formula in Equation 1 to calculate the current density at a holiday location.

$$I = (8 * Vac) / (\rho * \pi * d) \qquad \text{(Equation 1)}$$

Where:

i = Current Density (A/m^2)

V_{ac} = Pipe-to-Soil Voltage (Volts)

ρ = Soil Resistivity (ohm-meters)

d = Holiday diameter (meters)

1.4.3 Determining Steady State Pipeline AC Voltage Limits

The primary factor in calculating AC density at coating holidays is induced AC voltage on the pipeline at these coating holidays. Since the local soil does not significantly change, lowering the induced AC pipeline voltage (by adding mitigation) also lowers the local AC density.

To analyze the possible AC corrosion effects on this pipeline section, calculations were completed to determine the AC current density exiting the pipeline, assuming a one (1) cm^2 circular coating holiday at each soil resistivity location.

1.5 DEFINITIONS

AC Corrosion: The corrosion reaction associated with an AC electric current leaving the metal pipeline surface, due to an induced AC voltage on the pipeline.

AC Electrical Interference (Electromagnetic Interference): A coupling of energy from an electrical source (such as an electrical power line) to a metallic conductor (such as a pipeline) which at low frequencies (in the range of power system frequencies) occurs in the form of three different mechanisms; capacitive, conductive and inductive coupling. Electrical interference can produce induced voltages and currents in the metallic conductors that may result in safety hazards and/or damage to equipment.

Coating Stress Voltage: This is the potential difference between the outer surface of a conductor (e.g., pipelines, cables, etc.) coating and the metal surface of the conductor, and results from inductive and conductive potentials.

Capacitive Coupling: Capacitive coupling occurs as a result of an energized electrical source (e.g., power line) that produces a power line voltage between a conductor (such as a pipeline) and earth where the conductor is electrically insulated from the earth. An electric field gradient from the electrical source induces a voltage onto the conductor insulated from earth, which varies primarily according to the distance between the source and the conductor, the voltage of the source and the length of parallelism.

Conductive Coupling: When a fault current flows from the power line conductor to ground, a potential rise is produced in the soil with regard to remote earth. A conductor, which is located in the influence area of the ground for the power line structure, is subject to a potential difference between the local earth and the conductor potential. Conductive coupling is a localized phenomenon that acts upon the earth in the vicinity of the flow of

current to ground.

Conductive Earth Potential: This is the potential that is induced onto a conductor due to the energization of the surrounding earth by the current leaking from the power line structure.
Dielectric Breakdown: The potential gradient at which electric failure or breakdown occurs. In this case, it is pertinent to the coating of the pipeline and the potential at which damage to the coating will occur.

Earth Surface Potential: When a single-phase-to-ground fault occurs at a power line structure, the structure injects a large magnitude current into the earth and therefore raises soil potentials in the vicinity of the structure. These potentials are referred to as earth surface potentials.

Fault Condition: A fault condition is a physical condition that causes a device, a component, or an element to fail to perform such as a short circuit or a broken wire. As a result, an abnormally high current flows from one conductor to ground or to another conductor.

Inductive Coupling: Inductive coupling is an association of two (2) or more circuits with one another by means of inductance mutual to the circuits. The coupling results from alternating current in an energized conductor (e.g., power line) which is more or less parallel with a passive (non-energized) conductor. Inductive coupling acts upon the entire length of a conductor.

Inductive Pipeline Potential: The potential induced onto a pipeline during steady state or fault conditions that results from the mutual coupling between the energized conductor (power line) and the pipeline.

Load Condition: A load condition for a circuit is the amount of rated operating electrical power that is transmitted in that circuit under normal operating conditions for a specific period of time.

Local Earth: Local earth is the earth in the vicinity of a conductor, which is raised to a potential, typically, as a result of the flow of fault current to ground. In the case of a pipeline, which has a good coating and does not have grounding conductors connected to the pipeline where the earth potential rise occurs, the "local" earth will be the same as the "remote" earth.

Permeability: Permeability is a term used to express various relationships between magnetic induction and magnetizing force.

Potential Difference: The relative voltage at a point in an electric circuit or field with respect to a reference point in the same circuit or field.

Remote Earth: Remote earth is a location of the earth away from where the origin of the earth potential rise occurs that represents a potential of zero Volts.

Steady State Condition: A steady state condition for a power system is a normal

operating condition where there is negligible change in the electrical power transmitted in a circuit over a long period of time.

Step Voltage: The difference in surface potential experienced by a person bridging a distance of 1 meter with his feet without contacting any other grounded conducting object.

Touch Voltage: The potential difference between the Ground Potential Rise and the surface potential at a point where a person is standing with his hand in contact with a grounded structure.

1.6 AC MITIGATION SYSTEM DESIGN OBJECTIVES

An AC mitigation system designed to protect a pipeline subject to AC interference effects must achieve the following four (4) objectives:

i) During worst-case steady state load conditions for each electric transmission circuit, reduce AC pipeline potentials with respect to local earth to acceptable levels for the safety of operating personnel and the public.

ii) During fault conditions on the electric transmission circuits, ensure that pipeline coating stress voltages remain within acceptable limits in order to prevent damage to the coating or even to the pipeline steel.

Damage to the coating can result in accelerated corrosion of the pipeline itself. Coating damage can occur at voltages on the order of one thousand (1,000) to two thousand (2,000) Volts for bitumen coated pipelines, whereas damage to polyethylene or fusion bonded epoxy coated pipelines occurs at higher voltages, i.e., greater than five thousand (5,000) Volts.

iii) During fault conditions on the electric transmission circuits, ensure the safety of the public and of operating personnel at exposed pipeline appurtenances.

ANSI/IEEE Standard 80 specifies safety criteria for determining maximum acceptable touch and step voltages during fault conditions. Special precautions must be taken by maintenance personnel when excavating inaccessible portions of the pipeline to ensure safety in case of a fault condition.

iv) During worst-case steady state load conditions for each electric transmission circuit, reduce AC current densities through coating holidays to prevent possible AC corrosion mechanisms on the pipeline.

Table 1-1 depicts the 24” Empire State pipeline design criteria

Table 1-1: Design Criteria for Personnel Safety, and Protection Against Damage to the Pipeline Coating

Criteria	Steady State Maximum[1] (Volts)	Fault Maximum (Volts)
Exposed Pipeline Appurtenance Touch Voltage	15	-----
Exposed Pipeline Appurtenance Step Voltage	15	-----
Buried Pipeline Touch Voltage	15	-----
Coating Stress Voltage	-----	5,000

[1] With respect to "Local Earth"

2 FIELD DATA

2.0 PHYSICAL LAYOUT

Ten (10) electric transmission circuits parallel or cross the pipeline in the area of the Station 80 5th Bay expansion project, as described below:

- From approximate GPS coordinate 43.053534° N, 77.709338° W to GPS coordinate 43.053515° N, 77.683682° W, the pipeline parallels two (2) NYPA and one (1) RG&E electric transmission circuits.

- From approximate GPS coordinate 43.053515° N, 77.683682° W to GPS coordinate 43.053181° N, 77.673229° W, the pipeline parallels five (5) RG&E electric transmission circuits.

- From approximate GPS coordinate 43.053299° N, 77.671909° W and continuing east, the pipeline parallels two (2) NYPA electric transmission circuits.

- From Station 80 continuing north, three (3) RG&E electric transmission circuits do not cross or parallel the pipeline but are in close proximity to it and were considered for this study.

The ten (10) electric transmission circuits in the area of the Station 80 expansion project and the approximate pipeline GPS coordinates are listed in Table 2-1.

Table 2-1: Regions of Influence by Electric Transmission Circuits on the Pipeline

Transmission Circuit Name	Power Company	Line Size (kV)	GPS Coordinate Range
CHR-1	NYPA	345	43.053534°N, 77.709338°W @ proposed Station 255 to 43.053181°N, 77.673229°W @ Station 80
CHR-2	NYPA	345	43.053534°N, 77.709338°W @ proposed Station 255 to 43.053181°N, 77.673229°W @ Station 80
Future Circuit 40	RG&E	345	43.053534°N, 77.709338°W @ proposed Station 255 to 43.053181°N, 77.673229°W @ Station 80

Transmission Line 1	RG&E	Valve	43.054510°N, 77.683851°W @ Station 419 to 43.054724°N, 77.673030°W @ Station 80
Transmission Line 2	RG&E	Valve	43.054510°N, 77.683851°W @ Station 419 to 43.054724°N, 77.673030°W @ Station 80
Transmission Line 3	RG&E	Valve	43.053181°N, 77.673229°W @ Station 80 to 43.053337°N, 77.648436°W
Transmission Line 4	RG&E	Valve	43.053181°N, 77.673229°W @ Station 80 to 43.053337°N, 77.648436°W
Transmission Line 5	RG&E	Valve	43.054723°N, 77.671714°W @ Station 80 to 43.062177°N, 77.666244°W
Transmission Line 6	RG&E	Valve	43.054723°N, 77.671714°W @ Station 80 to 43.062177°N, 77.666244°W
Transmission Line 7	RG&E	Valve	43.054800°N, 77.673333°W @ Station 80 to 43.062177°N, 77.666244°W

Note: All referenced GPS coordinates are based on information provided by National Fuel Gas Company and Google Earth files created by ARK Engineering

2.1 PIPELINE DATA

The effective coating resistance of a pipeline is a conservative value obtained from previous research on coating resistances for in-service coated pipelines.

1) Coating Resistance of 24" pipeline 500,000 ohm-ft^2

The characteristics of the pipeline will be as follows:

- Relative resistivity: 10 (with respect to annealed copper)
- Relative permeability: 300 (with respect to free space)
- Pipeline diameter: 24"
- Pipeline depth: Minimum 3.5' Cover (Top of pipe to natural grade)
- Pipeline wall thickness: 0.350"
- Coatings: Fusion Bonded Epoxy

2.2 SOIL RESISTIVITY MEASUREMENTS

This AC electrical interference analysis was based on soil resistivity measurements recorded during our previous AC interference analysis on the Empire pipeline at locations along the pipeline route, using equipment and procedures developed especially for this type of interference study. ARK Engineering personnel conducted these soil resistivity measurements on August 27, 2006. Soil resistivity measurements at three (3) sites were used for this Station 80 expansion project. This measurement data is outlined in Appendix A.

Soil resistivity measurements are used to calculate the ground resistance of electric transmission line structures, assess the gradient control performance of AC mitigation systems and gradient control mats, as well as to determine the conductive coupling of the pipeline through the earth from nearby faulted electric transmission circuit structures. The conductive coupling has an important effect on touch and step voltages at proximate valve sites and on pipeline coating-stress voltages.

Past experience has shown the need for a special measurement methodology for environments that are subject to electrical noise due to the presence of nearby high voltage electric transmission circuits. When conventional methods are used, the instrumentation can pick up noise from the nearby electric power circuits and indicate resistivity values much higher than reality at large electrode spacing, suggesting that deeper soil layers offer poorer grounding than they actually may. Resistance readings can be inflated by a factor of four (4) or more. This error can result in conservative mitigation designs.

2.2.1 Soil Resistivity Measurement Methodology

Measurements conducted by ARK Engineering personnel were based upon the industry recognized Wenner four-pin method, in accordance with IEEE Standard 81, "IEEE Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System", using the Biddle Meter DET2/2 Digital Resistance Meter.

The electrode spacing varied from point one-five (0.15) meters to twenty-five (25) meters. Apparent resistivity values that correspond to the measured resistance values can be calculated using the expression:

$$\rho = 2\pi aR$$

Where: ρ = Apparent soil resistivity, in ohm-meters (Ω-m)
a = Electrode separation, in meters (m)
R = Measured resistance, in ohms (Ω)

In practice, four rods are placed in a straight line at intervals "a", driven to a depth that does not exceed one-tenth of "a" (0.1*a).

This results in the approximate average resistance of the soil to a depth of "a" meters.

2.2.2 Soil Resistivity Data

Soil resistivity measurements were used to derive an equivalent soil structure model in the area of Station 80. This multilayer soil model is representative of the changing soil characteristics as a function of depth. The inductive coupling interference modeling uses the bottom-most soil resistivity layer from the multilayer model. The complete multilayer soil characteristics are used to calculate the conductive and total AC interference effects. Touch voltage, coating stress voltage, and touch & step safety limits all use the complete multilayer soil model.

The bottom layer soil resistivity values were used for calculating electric transmission circuit parameters and inductive interference effects on the pipeline.

Table 2-2: Bottom Layer Soil Resistivity Values

Soil Resistivity Location No.	Approximate GPS Coordinate	Bottom Layer Resistivity (Ω-m)
1 (NYPA line @ East River Rd - east side)	43.055112°N, 77.690006°W	84.08
2 (Brooks Rd)	43.050311°N, 77.670815°W	17.11
3 (I390-I90 interchange)	43.049434°N, 77.645387°W	70.13

3 MODELING DETAILS

3.0 STEADY STATE CONDITIONS

Peak AC load currents, assumed by ARK Engineering based upon industry experience, were used to compute the additional maximum steady state inductive AC interference effects as a result of the Station 80 expansion on the pipeline in the area of the station.

Although these circuits may not be loaded to this level, the assumed data constitutes a realistic scenario if other critical circuits are out of service and the load must be redirected through these circuits. Therefore, under normal conditions, the steady state AC interference levels should be significantly less than those reported in this study.

Table 3-1 indicates the peak load currents for this AC interference analysis.

Table 3-1: Transmission Circuit Assumed Peak Current Ratings

Power Company	Circuit Name	Assumed Peak Load Current (A)
NYPA	CHR-1	1,500
NYPA	CHR-2	1,500
RG&E	Circuit 40	1,500
RG&E	Transmission Line 1	1,000
RG&E	Transmission Line 2	1,000
RG&E	Transmission Line 3	1,500
RG&E	Transmission Line 4	1,500
RG&E	Transmission Line 5	1,000
RG&E	Transmission Line 6	1,000
RG&E	Transmission Line 7	1,000

3.1 FAULT CONDITIONS

To determine the additional maximum AC interference effects of a faulted circuit on the pipeline in the area of Station 80 the model included single phase-to-ground fault branch currents on each of the RG&E electric transmission circuits.

Fault conditions were simulated on the electric transmission circuits in the area of the station expansion. Single phase-to-ground branch currents were used to calculate any additional fault current effects on grounded tower structures along each electric transmission circuit in the area of Station 80.

Reference Appendix C for all fault data used in this analysis.

3.2 SAFETY CRITERIA

The safety criteria established as part of this analysis is based upon the ANSI/IEEE Standard 80, "IEEE Guide for Safety in AC Substation Grounding" and the following assumptions:

- A surface layer of six inches (6”) of gravel at all aboveground pipeline locations (1,000 Ohm-meter gravel unless otherwise noted)
- A 50 kg (110 lbs.) person having a body resistance (R_b) of 1,000 Ω
- A worst case breaker failure fault clearing time (t_s) of 30 cycles was assumed for all fault condition scenarios.

3.3 MODELED INTERFERENCE LEVELS

ARK Engineering performed this AC interference analysis using state of the art modeling software. The output file plots for the steady state and simulated fault conditions on the ten (10) electric transmission circuits are included in Appendix B.

3.3.1 Steady State Conditions - The additional induced AC pipeline potentials on the pipeline, as a result of the station expansion, were computed with the electric transmission circuits operating at peak load conditions. The results are summarized in Appendix B.

The computed additional induced AC pipeline potentials as a result of the station expansion, were below the maximum allowable design limit of fifteen (15) Volts along the Empire pipeline in the area of the station.

Additional induced AC pipeline potentials reached a maximum of approximately five and one half (5.5) Volts, with respect to remote earth, at approximate GPS coordinate 43.053811° N, 77.694916° W. At this location, the pipeline parallels two (2) NYPA electric transmission circuits and one (1) RG&E electric transmission circuit.

Table 3-2 outlines the additional computed maximum induced AC pipeline potential at peak load conditions on the electric transmission

circuits, with the existing AC mitigation system included in the modeling and analysis.

Table 3-2: Additional Maximum Induced Potentials on the Pipeline at Peak Load Conditions

Pipeline		GPS Coordinate	Maximum Induced Potential (V)	Design Limit (V)
24" Empire State Pipeline	Existing AC Mitigation	43.053811°N, 77.694916°W	5.49	15

Reference Appendix B for plots of the computed induced AC pipeline potentials on the pipeline in the area of the station expansion.

3.3.2 Fault Conditions - As outlined in Chapter 1 of this report, when an electric transmission circuit fault occurs at a grounded structure (transmission tower) in proximity to a pipeline in a joint corridor, the induced AC pipeline potential is essentially out of phase with the earth potentials developed by conduction near the faulted structure. Therefore, inductive and conductive interference effects reinforce each other in terms of coating stress voltages and touch voltages.

3.3.2.1 Inductive Interference – Inductive interference effects to the pipeline were computed and analyzed during simulated fault conditions on each of the ten (10) electric transmission circuits. This was undertaken to determine the maximum induced AC pipeline potentials at all points along the pipeline, with the existing AC mitigation system on the Empire pipeline included in this analysis.

3.3.2.2 Conductive Interference – The configuration of the electric transmission circuit towers and their grounding systems was used to determine earth surface potentials in proximity to the structures and the pipeline during a simulated single phase-to-ground fault condition.

3.3.2.3 Total Fault Current Interference – The additional maximum total pipeline coating stress voltage was computed for each point along the pipeline. This is the sum of the inductive and conductive AC interference effects. The maximum pipeline coating stress voltage was calculated at three thousand six hundred seventy (3,670) Volts. This value was calculated at GPS coordinate 43.053811° N, 77.694916° W. This peak voltage is the result of a simulated fault on the 345 kV NYPA CHR-1 electric transmission circuit that parallels the pipeline at this location.

The maximum total coating stress voltage value is outlined below in Table 3-3.

Table 3-3: Maximum Coating Stress Voltage on the Pipeline under Fault Conditions

Pipeline	Transmission Circuit Faulted	Approximate Location (GPS Coordinate)	Maximum Coating Stress Voltage (V)
24" Empire State Pipeline	CHR-1	43.053811°N, 77.694916°W	3,670

Appendix B includes plots of the coating stress voltage on the pipeline during simulated fault conditions on the electric transmission circuit structures.

3.4 AC CORROSION ANALYSIS RESULTS

To analyze the possible AC corrosion effects to this pipeline, calculations were completed to determine the AC density based upon induced AC pipeline voltages, assuming a one (1) cm^2 circular coating holiday, along the pipeline and the existing AC mitigation system included in the calculations.

The computed induced pipeline voltages are shown in Appendix B.

For this pipeline, a peak AC density of approximately thirty-four (34) A/m^2 was calculated at GPS coordinate 43.053318° N, 77.649478° W. At this location, the pipeline parallels two (2) NYPA electric transmission circuits.

Table 3-4 outlines the computed maximum AC density at assumed maximum load conditions on the electric transmission circuits.

Table 3-4: Maximum Coating Holiday AC Current Density

Pipeline		GPS Coordinate	Maximum Current Density (A/m^2)
24" Empire State Pipeline	Without AC Mitigation	43.053318°N, 77.649478°W	34.07

Reference Appendix B for plots of the computed AC density on the pipeline.

4 CONCLUSIONS

4.0 CONCLUSIONS

The 24" Empire State pipeline and the eight (8) RG&E electric transmission circuits and two (2) NYPA electric transmission circuits in the area of the Station 80 expansion project have been modeled and analyzed as described in this report.

Computer modeling and analysis, using peak load currents on the electric transmission circuits, indicate the following:

- Additional steady state induced AC pipeline voltages do not exceed the fifteen (15) Volt design limit along the pipeline under these load conditions on the electric transmission circuits.

- Additional pipeline coating stress voltages will not exceed the five thousand (5,000) Volt design limit for a single phase-to-ground fault on the electric transmission circuits.

This analysis results in interference levels that are conservative. Under normal operating conditions, the AC interference levels on the pipeline should be less than reported in this study.

4.1 ASSUMPTIONS

During the modeling and analysis of the AC interference effects on the pipeline, various assumptions were required. These assumptions are outlined below in no particular order:

a. Low voltage distribution taps were not included in this analysis.

b. A coating resistance value of 500,000 Ω-ft^2 was used for the pipeline. This is a conservative value used for new pipelines.

c. Load and fault data was assumed by ARK Engineering using conservative values based on the previous AC interference analysis conducted on the Empire pipeline in this area.

d. A coating holiday size of 1 cm^2 was used in the calculation of AC current density.

5 RECOMMENDATIONS

5.0 RECOMMENDATIONS

As outlined in the previous chapter, additional induced AC pipeline potentials were calculated as a result of the Station 80 5th Bay expansion project. These values will be below the design limits detailed in Table 1-1, for the pipeline during maximum projected future emergency steady state load conditions on the eight (8) RG&E electric transmission circuits and two (2) NYPA electric transmission circuits.

As a result of the Station 80 expansion project, no additional AC mitigation is recommended for the Empire pipeline in the area of the substation at this time.

ARK Engineering recommends monitoring of the induced AC pipeline potentials at the test stations near the Station 80 site. A data logger or remote monitoring unit with coupon test stations could record AC voltage trends and AC density values in the area of the substation.

Please call the author if you have questions or require additional information regarding this report.

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June 10, 2015

Hon. Kathleen H. Burgess, Secretary
State of New York Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 11-T-0534 - Application of Rochester Gas and Electric Corporation for a Certificate of Environmental Compatibility and Public Need for the Construction of the "Rochester Area Reliability Project," Approximately 23.6 Miles of 115 Kilovolt Transmission Lines and 1.9 Miles of 345 Kilovolt Line in the City of Rochester and the Towns of Chili, Gates and Henrietta in Monroe County

Dear Secretary Burgess:

As attorney for Rochester Gas and Electric Corporation ("RG&E) in the above-referenced proceeding, I am submitting this letter and the accompanying Milestone Schedule for filing with the Public Service Commission as the update of the RG&E's major milestone schedule required by the Commission at page 14 of the its November 15, 2013, Order Reopening the Record for the Re-Examination of Location of Substation 255 and the Route of Circuits 40, 940 & 941

On December 23, 2015, RG&E notified the Commission and all parties to this proceeding that developments in Case 14-E-0270, Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant, will result in delays in the Rochester Area Reliability Project ("RARP") construction schedule to allow RG&E to complete work, referred to by RG&E as the "Ginna Retirement Transmission Alternative" or "GRTA", required to provide reliable service if the Ginna Power Plant is retired.

Additionally, as the attached schedule indicates, neither Segment II of the Environmental Management and Construction Plan ("EM&CP") for the RARP nor RG&E's application for an amendment of the RARP certificate of environmental compatibility and public need concerning work on Circuits 940 and 941 of the RARP has yet been approved by the Commission. Finally, the Commission has not yet issued its decision on an application for rehearing that seeks to have the location of Station 255 of the RARP moved from Site 7 to Site 20, and the Administrative Law Judges have required RG&E to submit additional studies on the possibility of constructing Station 255 at Site 20.

The attached schedule provides projected dates for the start and completion of each task listed, rather than the duration of each task in months, which was provided in previous schedules. The schedule includes modifications made as a result of the GRTA. It has been prepared on the assumption that EM&CP Segment II and the application for amendment of the certificate for work on Circuits 940 and 941 will be approved substantially as filed by RG&E, and that Site 7 will remain the preferred location for Station 255, but it provides alternative dates should Site 20 be selected. It also assumes that further proceedings on the additional studies on siting Station 255 at Site 20 will be completed in time to allow a Commission order selecting the site of Station 255 by April 2016.

A copy of this update is being served simultaneously on all parties on the Commission's Party List for this proceeding and on Administrative Law Judges Elizabeth Liebschutz and Michelle Phillips.

Respectfully submitted,

John D. Draghi

Cc: All Parties
E. Liebschutz
M. Phillips

Rochester Gas and Electric Corporation

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant
Case 14-E-0270

INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.1)

Request No.: GNP-15-206

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

RG&E T&D Planning and Operating Criteria

Provide the latest versions of RG&E's transmission and distribution planning criteria and guidelines, and operating criteria and guidelines.

Response:

See attached files:

- Attachment 1 - Transmission Planning Criteria
- Attachment 2 - Distribution Planning Criteria
- Attachments 3 and 4 - Operating Criteria

IBERDROLA USA
ELECTRIC TRANSMISSION PLANNING MANUAL – CRITERIA & PROCESSES

New York State Electric & Gas (NYSEG),
Rochester Gas and Electric (RG&E),
Central Maine Power (CMP) and
Maine Electric Power Company (MEPCO)

Reviewed and Approved By: Curtis Beveridge		Date: 11-06-2014
Reviewed and Approved By: Timothy Lynch		Date: 11-06-2014
Approved By: Alonso, Beatriz		Date: 11-06-2014

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Revision	Date	Description	Author
00	7-28-2011	Issued for Iberdrola-USA Planning consolidation	IUSA System Planning
01	10-31-2014	Update for: - Maine PUC planning assumptions - Criteria vs Process document organization change	Denise Howe, Justin Michlig, Chris Morin

1 Introduction

This document defines transmission system design criteria and guidelines that maintain an acceptable electric transmission system that meets the needs of Iberdrola USA (IUSA) customers in a safe, reliable and economical manner.

Planning criteria allow for the identification of developing problems and ensure that plans adequately address service requirements. The IUSA transmission planning criteria is to be utilized when analyzing the transmission system reliability as part of reliability studies and new transmission interconnections.

Failure to meet any one criterion can justify a system improvement. Some criteria, such as those dealing with safety, require a more immediate response and will take priority over other problems that may be deferred. The transmission planners must evaluate each proposed project against the planning criteria and establish its priority. In addition to the priority of a project, those deemed necessary for compliance with Reliability Standards will be non-discretionary as they are established by deterministic North American Electric Reliability Corporation (NERC) standards.

The System Planning Department reserves the right to routinely amend any of these criteria at any time.

This document is broken down in the following sections:

- Section 1 – Introduction: A description of the use of this document
- Section 2 – Tools: A listing of software utilized by IUSA System Planning
- Section 3 – Description of the Transmission System: An introduction to the IUSA system and operating companies that make up IUSA
- Section 4 – Transmission Planning Criteria: Metrics that the transmission system must perform within.
- Section 5 – Simulation and Assumptions: Assumptions and guidance for simulations, including modeling, scenarios and sensitivities
- Section 6 – Interconnections: Procedures for interconnection to the transmission system for generation, load and transmission ties are explained
- Section 7 – External Drivers: A description of processes external to IUSA that each operating company must adhere to
- Section 8 – Project Prioritization: An overview of how projects are ranked with respect to each other

1.1 Jurisdiction of Criteria

IUSA strives to ensure that its transmission planning criteria does not conflict with jurisdictional authority. When analyzing the transmission system the order in application of authority should be:

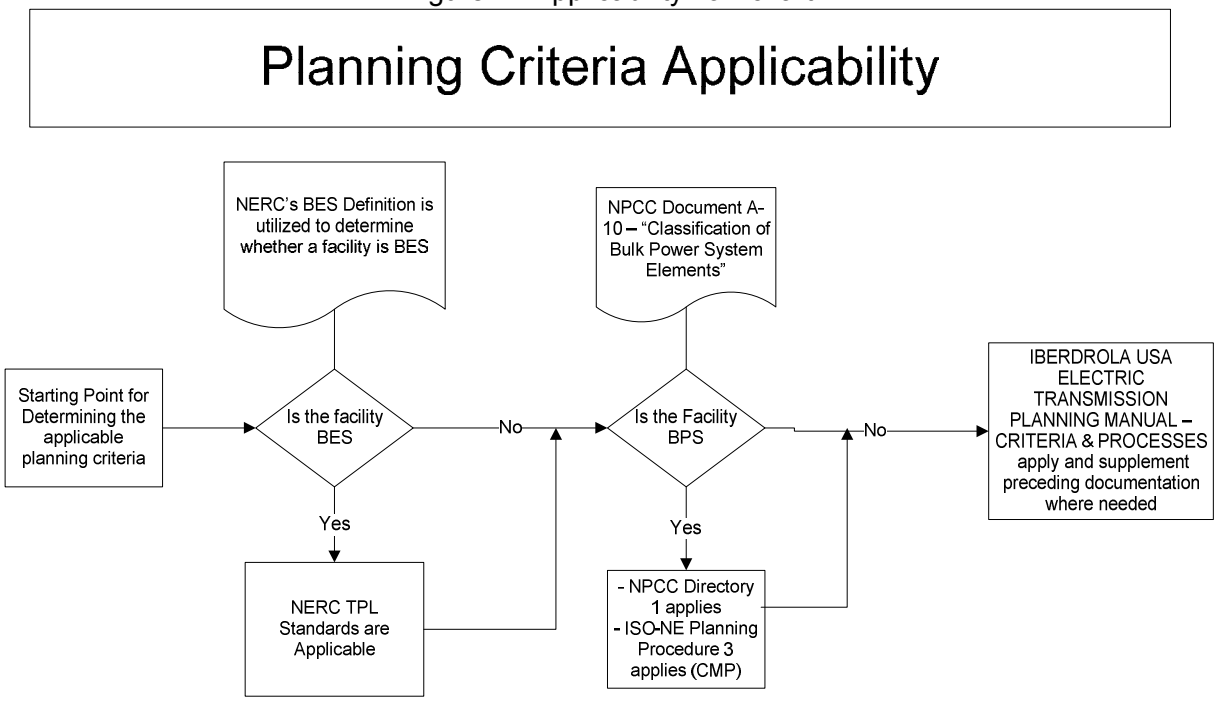
1. NERC Reliability Standards
2. NPCC Standards
3. ISO criteria through Open Access Transmission Tariff (OATT) or legal agreement
4. Local Transmission Planning Criteria

The IUSA Electric Transmission Planning Manual is designed to provide criteria required to supplement federal and regional standards (such as voltage limits). This document is designed to contain all criteria to study the reliability of its local transmission system and maintain compliance with state statutes along with commission orders[1].

1.2 Applicability Flow Chart

To aid in determining the application of standards and criterion, the following flow cart is provided (Figure 1).

Figure 1: Applicability flow chart



[1] Methods for planning and designing the local transmission system are consistent with the Maine Public Utilities Commission order in Docket No. 2011-00494, "Investigation into Maine Electric Utilities Transmission Planning Standards and Criteria"; which established "Safe Harbor" assumptions and practices to support Certificates of Public Convenience and Necessity.

2 Transmission Planning Tools

IUSA utilizes multiple types of power system simulation software. This software allows engineers to conduct reliability testing, analyze potential system deficiencies and test for solutions. The following products are utilized in addition to the standard suite of Microsoft Office and Windows tools.

PSS®E

Siemens Power System Simulator for Engineering (PSS®E) is a power system simulator used for transmission analysis. The primary uses within IUSA are power flow and dynamic simulations. In addition to typical transmission planning analysis, IUSA utilizes PSS/E for studying Geomagnetic Induced Currents (GIC).

ATPDraw

ATPDraw is an Electromagnetic Transients Program (EMTP) utilized occasionally for detailed transmission system analysis. This program can be utilized to simulate many power system actions including back-to-back capacitor switching, switching impulses, transformer energization, etc…

ASPEN – OneLiner™

This program is primarily utilized by the Electric System Engineering (aka System Protection Engineering) department within IUSA. System Planning utilizes the program to calculate short circuit current and system impedance information. This contributes to the required transmission system short circuit analysis and providing input to dynamic simulations performed in PSS®E.

3 Description of the IUSA Transmission System

Iberdrola USA is a subsidiary of the global energy leader Iberdrola, SA. IUSA transmission facilities owned by the companies of Central Maine Power (CMP), New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E). The IUSA transmission infrastructure supports more than 1.8M customers with ~8200 miles of transmission lines and over 900 substations. As regulated utilities, each company has various obligations and commitments to ensure construction of a reliable transmission system.

The three operating companies of the IUSA family fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), NERC, and the NPCC. In addition to the federal and regional entities, CMP is under the purview of the New England Independent System Operator (ISO-NE) and the Public Utility Commission of Maine (MPUC). Similarly NYSEG and RG&E are part of the New York Independent System Operator (NYISO), New York State Reliability Council (NYSRC), and New York State Public Service Commission (NYPSC).

The Maine Electric Power Company (MEPCO) is also a transmission owning company located in the state of Maine. It consists of a majority stake ownership of CMP and minority ownership of Emera Maine. Criteria and responsibilities for CMP are also applicable to MEPCO. Together RG&E and NYSEG may be referred to as New York companies throughout this document.

3.1 Definitions of the Transmission System

The broadest definition of the transmission system is given by FERC. This definition is independent of operating voltage and states, “Moving bulk energy products from where they are produced or generated to distribution lines that carry the energy products to consumers.” Generally a FERC seven-factor test, established in FERC Order 888, is applied in the determination of transmission vs. distribution. Further clarification is left to the state for setting boundaries of transmission vs. local distribution.

In 2014 the NERC Bulk Electric System (BES) revised definition became effective. This defines clearly all facilities which are under the purview of the NERC Reliability Standards. All NPCC participants have registered their list of BES facilities with NPCC.

A more narrowly defined set of transmission elements is governed by NPCC’s Document A-10 “Classification of Bulk Power System Elements.” Bulk Power System (BPS) facilities are defined as those facilities whose performance affects the reliability of supply to other utilities and customers beyond the local area. The Bulk Power System is designed based on the requirements of the NPCC “Design and Operation of the Bulk Power System” (NPCC Directory #1) and other NPCC directories and criteria.

All IUSA operating companies participate within the purview of a regional Independent System Operator (ISO). These are ISO-NE for CMP and NYISO for RG&E and NYSEG. As a part of membership in an ISO, each member is bound to construct facilities that maintain reliability on the transmission system. These agreements bind CMP to utilize ISO-NE’s Planning Procedure 3 and approved Reliability Rules in New York.

Local transmission facilities are all other transmission facilities that are primarily used to supply local area load, large industrial customers and/or connect smaller generation. The local transmission system generally consists of facilities that operate between 115 kV and 34.5 kV. Distribution facilities dedicated to serving customers are covered by the IUSA Distribution Planning Criteria[2].

[2] Iberdrola USA Technical Manual, TM 1.61.00, “Distribution Planning Criteria”

RG&E supplies a portion of the City of Rochester from networked transmission facilities that are operated at 11 kV. These bi-directional flow network facilities are operated in parallel with the 115 kV and 34.5 kV transmission systems and are part of the transmission system.

4 Transmission Planning Criteria

This section is designed to house the metrics used to judge system performance. These criteria are to be met when analyzing Planning Events and Normal Contingencies.

4.1 Facility Ratings

IUSA utilizes ratings in its transmission planning studies to ensure safe operation without excessive loss of equipment life. Ratings to be used are consistent with those developed in compliance with the NERC FAC-008-3 standard for the BES and approved methods for local transmission facilities. Facility Rating Methodologies for each operating company are posted in a separate document. CMP utilizes the document "CMP Procedures for Determining and Implementing Ratings for Transmission Facilities." The CMP procedure relies on ISO-NE's PP-7 procedure in providing the technical direction of Facility Rating development and is supplemented by input assumptions developed by CMP. The New York operating companies rely on the "New York Tie-Line Rating Guide" for facilities newer than 1995 and the "Report of Task Force on Tie Line Ratings – NYPP" for facilities older than 1995.

Three categories of ratings are utilized:

1) **Normal Rating:** This rating is the continuous rating of the transmission facility adjusted to seasonal ambient conditions. There are no restrictions on utilization of the full normal rating for any extent of time.
2) **Long Term Emergency Rating (LTE):** For a time period up to 4 hours in New York and winter in Maine or 12 hours in Maine's summer season, facilities may be loaded past their Normal Rating and less than their LTE after a contingency. The transmission facility must return to a loading level below its normal rating once the time duration of the LTE has expired.
3) **Short Term Emergency Rating (STE):** This rating is applicable for short term loadings on transmission facilities after a contingency has occurred. This is assuming the pre-contingent loading is within the facility's normal rating. The maximum length of time that a facility may be loaded utilizing its STE limit is 15 minutes. After which the loading must decrease below LTE.
4) **Drastic Action Limit (DAL):** This rating has been developed for operational use only. It is not intended to be used as design criteria and is included for informational purposes only.

Table 1: Rating Applicability

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Normal (all facilities in)	Continuous	Normal Rating
Post Contingent	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating
	Between 15 minutes and LTE duration	Long Time Emergency (LTE) Rating

4.2 Voltage

4.2.1 Steady State

When analyzing the transmission system, voltage must remain within the steady state bandwidth of .95 – 1.05 V PU. This range is to be maintained prior to and after a contingency occurs on the transmission system with additions stated below. Performance with this voltage range is applicable to the contingencies described in Section 5.3.

Additions:

1) IUSA strives to provide adequate voltage to all customers. In addition to these limits customer voltage must remain within those specified in ANSI C84.1. The State of Maine also requires that CMP provide service to customers which meet voltage criteria within MPUC 65-407 Chapter 32 Section 2.04.
2) Post Contingent voltage is measure after automatic system actions have occurred (LTC, capacitor, SPS actions…).
3) Voltages on the 115 kV system as low as .92 PU may be accepted after two independent contingencies, such as a TPL-001-4 P6 event, as long as two conditions are met after automatic adjustments occur. a) The number of buses affected is three or less and b) customer voltages are adequately held to MPUC regulations. Modeling of multiple buses for a single voltage at a substation are to be counted as a single bus.
4) In NY, service to regulated distribution facilities allow for an expanded voltage bandwidth. During normal and single contingency conditions voltage supplied to regulated distribution facilities must maintain a voltage between .90 – 1.05 V PU. Service to unregulated distribution facilities requires the standard bandwidth presented of .95 – 1.05 V PU.

4.2.2 Flicker

IUSA considers the normal action of shunt connected transmission devices (either directly or through a transformer) to be within the scope of devices applicable to voltage flicker. The maximum allowable flicker on the transmission system by the starting of large motors, the switching of capacitor banks, or other devices is defined by the IEEE Standard 1453 flicker curve (see Figure 2). The "Borderline of Visibility" curve is used as the design criteria for the transmission system.

With all elements of the transmission system operating and in-service, the instantaneous bus voltages must not change by more than 3% while the number of switching events is limited to less than one per hour. Additionally, as seen on the curve, voltage flicker within the frequency range of 2 to 8 dips per second (characteristics of an arc furnace) shall be less than 0.5%.

In addition to the maximum voltage flicker threshold with all facilities in-service, IUSA also utilizes a criterion to test a facility out-of-service. With one element out of service a 5% flicker is acceptable for switching frequencies of one or less per hour. These criterions will not be applied retroactively to equipment already in-service. When retiring a transmission line, impacts to the magnitude of flicker should be considered.

Figure 2: Voltage flicker limitation curve

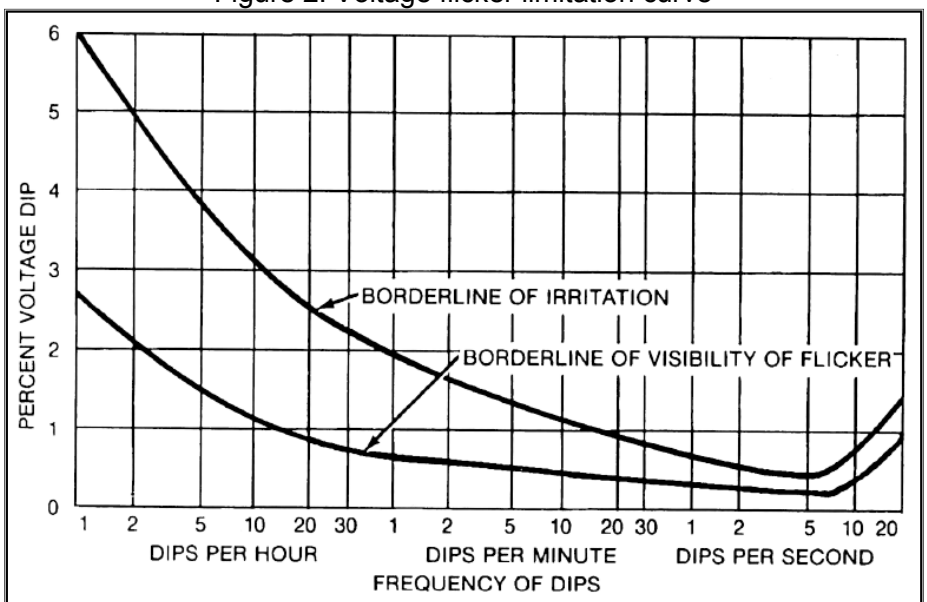


Figure A.1—Flicker tolerance curve from IEEE Std 141-1993/IEEE Std 519-1992

Voltage change during a fault, generation trip, or the operation of a series transmission element is not considered voltage flicker to be bound by this section.

4.3 Dynamic/Transient/Time Domain Simulation

4.3.1 Transient Voltage Response

CMP has adopted the use of ISO-NE's Transmission Planning Technical Guide Appendix E "Dynamic Stability Simulation Voltage Sag Guideline" as its criteria on transient voltage recovery. This is applicable to BES facilities and response to "Planning Events."

4.4 Frequency

Since the transmission network in the northeastern United States and Canada is well interconnected, frequency deviation is not usually a significant concern. The interconnected transmission systems of eastern North America typically have a frequency variation of a fraction of 1%. The Bulk Power transmission system is designed to comply with NERC/NPCC criteria for under-frequency load-shedding and generator frequency or speed protection. These criteria are designed to help survive islanding and stabilize system frequency at 60 Hz. The under-frequency load-shedding plan is a joint effort between the System Planning, System Protection, and System Operations Departments.

A Normal Operating State exists when the frequency is not less than 59.95 Hz or not greater than 60.05 Hz. An Alert State exists when the frequency is between 60.05 Hz and 60.10 Hz or between 59.90 Hz and 59.95 Hz. Finally, a Major Emergency exists when the frequency increases to 60.10 Hz and is sustained at that level or continues to increase, or declines to 59.90 Hz and is sustained at that level or continues to decline.

4.5 Short Circuit Criteria

System Planning coordinates with the System Protection and Engineering departments to ensure that short circuit analysis and breaker duty studies are conducted when new transmission system and interconnection projects are being considered. IUSA utilizes ASPEN ® to conduct its short circuit analysis. Table 2 contains the assumptions used for simulation of short circuit. Similar assumptions should be used with alternate software.

Table 2. ASPEN assumptions

ASPEN Short Circuit Modeling Assumptions		
X/R Options		
Compute ANSI x/r ratio		**YES**
Assume Z2 equals Z1 for ANSI x/r calculation		**YES**
X-only calculation	If X is 0 use:	0.0001 p.u.
R-only calculation	If R is 0 use:	Method 1
	Rc	0.0001 p.u.
	Typical X/R ratio (g) for generators	60
	Typical X/R ratio (g) for transformers	30
	Typical X/R ratio (g) for all other equipment	10
Fault Simulation options		
Pre-fault voltage	Assumed "Flat" with V(p.u.)	1.05
Ignore shunts	Loads	**YES**
	Transmission line G + jB	**YES**
	Shunts with + sequence values	-
	Transformer line shunts	-
Generator Impedance	Subtransient	-
MOV-protected series capacitor	Iterate short circuit solutions	**YES**
	Acceleration Factor	0.4
Define fault MVA as product of	Current and pre-fault voltage	-
Current limited generators	Ignore current limits	-
ANSI/IEEE Breaker Checking Options		
Fault types		3LG, 2LG, 1LG
For X/R calculation, use		Separate X-only, R-only networks
In 1LG faults, allow up to 15% higher rating for		Symmetrical current rated
Force voltage range factor K=1 in checking	Symmetrical-current rated breakers	**YES**
	Max design or higher	121
Miscellaneous options	Treat all sources as remote	**YES**
All generation modeled online to maximize fault current		**YES**

4.6 Load Loss Acceptability

Loss of Load (LOL) is an important measure of the transmission system dependence on specific system facilities and is one reliability indicator which provides engineers with quantitative methods for revealing system weaknesses.

4.6.1 Consequential Load Loss

Within Maine, during system intact conditions (all lines in service), up to 25 MW of load loss due to the normal operation of protective devices is allowed for a fault with normal clearing. The outages in consideration are listed under NERC TPL-001-4 as Planning Event P1 contingencies and similar outages on non-BES elements. A maximum of 60 MW may be accepted, in anticipation of a P1 outage (single outage on the local system), for consequential load loss while performing maintenance. The impact of consequential loss of load will be considered during planning studies in NY, but a maximum loss is not stipulated.

Customers other than IUSA taking service at a transmission level may elect to have more than 25 MW of load loss when choosing designs for interconnection.

4.6.2 Non-Consequential Load Loss

During a NERC Planning Event on the BES transmission system or single contingency on the Local Transmission system, IUSA does not allow the use of Non-Consequential Load Loss to maintain system performance criteria as a permanent solution[3].

For temporary measures, after the second contingency of a P6 event, Non – Consequential Load Loss will be permitted to bring the system within pre-contingent facility rating operating limits assuming STE ratings have not been exceeded. In addition for temporary reliability improvement, to ensure adequate voltage and protect customer equipment, Under Voltage Load Shedding (UVLS [4]) would be required to bring a low voltage conditions within criteria. In a condition of projected voltage collapse manual or automatic load shedding schemes will be insufficient.

[3] Non-Consequential Load Loss is only accepted on a temporary basis when allowed by NERC standards. A binding commitment to provide a solution must be developed to improve the transmission system post contingent response. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criterion is not met, an automatic means of bringing the system within boundaries, such as UVLS, should be temporarily used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

[4] UVLS Loss of load will only be accepted on a temporary basis. A binding commitment to provide a solution must be developed to improve the transmission system post contingent voltage response must exist. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criteria are not met, an automatic means of bring the system within boundaries, such as UVLS, should be used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

4.7 Harmonics

Harmonic distortion caused by customer load characteristics and capacitor banks shall be limited such that harmonic voltage distortion on the system shall not exceed any applicable ANSI standards for equipment connected to the system. Also, as stated in IEEE Standard 519-1992 (see below), voltage distortions shall not exceed 3% for any single frequency or 5% total harmonic distortion, and shall not injuriously affect equipment or its service to others. However, it is recognized that reasonable engineering judgment must be used in the application of these limits to balance compliance costs against adverse consequences of excess harmonic distortion.

Figure 3: Voltage distortion limits

Table 11-1—Voltage Distortion Limits

Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.0	5.0
69.001 kV through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5

NOTE — High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

5 Simulation and Assumptions

This section of the IUSA Electric Transmission Planning manual is designed to guide model setup, scenarios, and illustrate general study assumptions to use.

5.1 Model Selection

Selecting a model that represents the area in question is one of the most important steps of a transmission planning study. The model needs to have enough detail to represent the condition and location being studied yet not so much as to inhibit the completion of a study. IUSA System Planning engineers are directed to utilize engineering judgment along with direction from regulating bodies to ensure use of models that are effective in studies. When developing models and studies it is important to:

- Utilize ratings reflective of the time period being analyzed (5.1.1)
- Construct realistic transmission operating conditions (5.2),
- Conduct simulations of the spectrum of required contingencies (5.3)
- Forecast loads to ensure the system performs within the range of loading over time (5.4)
- Take into effect the higher forced outage rate of generation (5.5)

5.1.1 Ratings

Ratings for facilities used in studies need to adhere to the criteria under section 4.1. While monitoring for overloads on facilities, studies need to monitor the duration of ratings in accordance to section 4.1. It is recommended to utilize the normal rating of a facility in studies to ensure all potential issues are reviewed for their ability to reduce loading in applicable timeframes. Transmission Planning Engineers can gain access to ratings in each state by the following methods.

New York

For the ratings of all transmission lines operating between 345 kV and 69 kV refer to the most recent NYSEG and RG&E respective “Tie Line Rating” sheets.

For the ratings of all transmission lines operating at 46 kV or 34.5 kV refer to the NYSEG “Conductor Safe Ampere rating” sheet dated July 25, 1978.

CMP

All ratings to be used are located within the FactilityRatingsDB.mdb Microsoft Access database. The database resides with and is updated by System Engineering.

5.1.2 Flicker Studies

As fault current contributing devices are disconnected from the transmission system, larger changes in voltage are seen for switching components. Testing for system intact (all lines in-service) and strongest source loss should not be conducted using a model with all generation running. To ensure flicker limits are adhered to throughout the year, a spring light load or model representing realistic minimum generation in an area must be used.

5.2 Transmission System Operating Conditions

The transmission system is susceptible to facilities being forced out of service during outages. In addition, many pieces of equipment require routine maintenance or end-of-life replacement for which facilities must be de-energized. To perform construction activities on the transmission system or ensure adequate clearance to energized equipment, facilities may need to be removed from service. Collectively forced outages (contingencies) and Maintenance/Construction outages (Planned outages) may be referred to as “Outages” through the remainder of the planning criteria.

Transmission planning studies are conducted to analyze system Outages and ensure that the transmission system is capable of remaining within specified voltage, thermal, short circuit and stability criterion for various system conditions. When deficiencies are discovered, additional analysis is completed to identify the reinforcements that would allow the transmission system to operate under normal conditions and single outage contingency scenarios, as well as planned maintenance conditions at reduced load levels. Subsequent to their identification, reinforcements are budgeted as projects and constructed.

System Planning performs most analyses using a computer loadflow program. Models include existing and future system configurations. Generally engineers analyze simulations for winter and summer peak, as well as off-peak and minimum load conditions. Additional applicable scenarios may be analyzed to ensure that the transmission network will perform adequately under normal and "worst case" conditions.

5.2.1 Normal Operating Condition

Normal conditions are present during system intact (all lines & equipment in) periods. Normal conditions include extremes of customer loads, generator forced/scheduled outages, and "not dispatched" conditions. While this condition may not be the most common in terms of operating time, it serves as a benchmark against which to measure other conditions.

Both NERC and NPCC require considerations for the loss of equipment that have long lead times or be critical to reliability. An extended outage of a single generating plant or unit or a single bulk power transformer (115 kV and above on the low side) is also considered to be a Normal Operating Condition. Whenever a generating plant or unit or Bulk Power System transformer is going to be out of service for an extended period of time as a planned outage, System Planning will determine what impact the next contingency would have on the transmission system and recommend a solution to any system problems that may be identified.

5.2.2 Scheduled and Maintenance Outage Operating Condition

Frequently, system operators and field crews must remove a transmission network element from service. These elements may be removed to perform maintenance, construct new facilities, or provide electrical clearance for adjacent work being performed. Removal of elements for these conditions shall be considered in Transmission Planning analysis.

Analysis of the BES, BPS and other non-local jurisdictional facilities will be in accordance to applicable governing documents. When considering reliability on the local transmission system, defined single contingencies should be reviewed for facilities being scheduled out of service at a load level 85% of the 90/10 expected peak or at the load level expected for the time of the scheduled outage. It should be expected that mobile transformers will be available to support the transmission or distribution system, if needed for reliability. Also, consideration of the expected loss of load should be made.

5.3 Scope of Contingencies

IUSA utilizes all NERC TPL defined events for testing the BES, any additionally defined NPCC Directory 1 outages for testing the BPS and Single Outages for testing its local transmission system. These outages are applicable for both steady state and stability analysis.

This document defines Single Outage contingencies[5] as fault and normal clearing of the following:

a. Transmission line
b. Transformer
c. Generator
d. Opening one terminal of a facility without a fault
e. Capacitor bank, Reactor or static VAR compensator
f. Double-circuit transmission tower: [6]

Per the Maine Public Utility Commission's "Safe Harbor" provisions, when simulating outages on the BES other than the single outages defined above result in problems on the local transmission system, justification of the need must be substantiated unless they also cause performance issues on the BES.

5.3.1 Multiple Contingencies

IUSA strives to accurately and realistically assess the occurrence of multiple contingency events on the transmission system. Two time frames emerge as being important to test the system capabilities for a second outage.

30-minute Operator Actions

NPCC and ISO-NE have issued guidance on how to consider the 30 minute operator adjustment time in-between the completion of the first contingency event and in preparation for the second contingency. NPCC applies this criterion to loss of a "critical" facility[7] prior to a second contingency occurring and within ISO-NE this applies to all PTF facilities[8]. During this time period the following actions are allowed.

1. 10 minute quick-start and reserve generation
2. Phase shifting transformers (PARs)
3. HVDC controls
4. LTCs
5. Series and shunt capacitors/reactors

[5] In addition to the list of single contingencies, bus faults should be considered in the planning and construction of the local transmission system. It is recognized that this is a similar scenario to faults on the BES transmission system which are generally less frequent due to increased clearance

[6] A double-circuit transmission tower outage should be considered as a single contingency if the multiple-circuit towers are used for more than station entrance and/or exit purposes and exceed more than five towers in length. However, double-circuit towers may not be considered as a single contingency if a special design is constructed to significantly reduce the likelihood of lightning strikes and/or back-flashes.

[7] NPCC Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System," Section 5.4

[8] ISO-NE "Draft Transmission Planning Technical Guide," Section 12.5

Post Operator Actions (May exceed 30 minutes)
Not all operator/field crew actions are expected to take place within the 30 minute operating window established by NPCC. Expected actions that may take longer than 30 minutes due to dispatching line crews to open/close manually operated switches, generation ramping capabilities, calling a generator online, enabling or disabling a non SCADA SPS should be taken into consideration. These conditions could last for days or weeks while equipment is repaired. The following considerations should be realized in testing the system once all expected actions should occur on the transmission system prior to a second contingency.

A) Reduction of generation behind a limiting interface to meet line-out interface limits
B) Restoration of load served from a transmission tap without Motor Operated Disconnects (MOD) and remote or automatic control operation.
C) Distribution field tie operation to restore lost load

5.3.2 Stability
Transmission system studies shall be conducted such that system voltages and transmission line and equipment loadings shall be within normal limits during all pre-disturbance conditions and within applicable emergency limits during all system load and generation conditions that exist following the disturbances discussed below.

Stability of the Bulk Power and Local transmission systems shall be maintained during and after the most severe contingencies stated below.

A) A permanent 3-phase fault on any generator, transmission line, transformer, or bus section with normal fault clearing.

B) A permanent phase to ground fault on a circuit breaker with normal fault clearing.

C) Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission lines on a multiple circuit tower with normal fault clearing. If multiple circuit towers are used only for station entrance and/or exit purposes, and they do not exceed five towers at each station, this condition can be considered as an acceptable risk.

D) A permanent phase to ground fault on any transmission line, transformer, or bus section with delayed fault clearing.

E) Loss of any single system element without a fault.

Extreme contingencies/events are analyzed as applicable under reliability studies. Engineering judgment is utilized to select the contingencies which include the following: 1) a permanent 3-phase fault on any generator, transmission line, transformer, or bus section with delayed fault clearing; 2) the loss of right of way; 3) the loss of a transmission substation; 4) the loss of all of the units at a generating plant; or 5) other relevant Extreme Events listed in TPL-001-4.

5.4 Load

Development and utilization of load information within planning studies has a large impact on results. Within each operating area (ME, NY) of IUSA the development of the loads is handled within the scope of the associated ISO and local process.

For CMP, there is a distinct difference between large area regional study process (such as the TPL reliability assessment or ISO-NE Needs Assessment) and local area studies:

- **System Compliance or Regional study:** The TPL, Need and Solutions type studies are required to utilize the latest "Capacity, Energy, Loads, and Transmission (CELT)" forecast load level over the 1-10 year planning horizon to be accepted by ISO-NE. The ISO-NE develops this forecast for New England which is broken down by state and transmission owner. The CELT report also contains the capacity supply obligations, qualified capacities for the generators that participate in the market, and load demand response data. The CELT report values are updated on an annual basis. There are generally 90/10, 50/50, shoulder, and light loads that are used according to the type of study and Planning Procedures.

- **Local Area Study:** CMP uses an internal peak load forecast that is derived from an energy forecast. This is sub-divided into the various Service Center areas within CMP based on customer field operations. These districts often don't exactly line up with the 14 CMP planning areas, but are comparable. The 90/10 load forecast change over the planning horizon is applied to area historical coincident peaks. The Maine PUC accepted this as a "safe harbor" provision. Spot load additions to the CMP transmission system are included in the forecast where known and studied ad-hoc as necessary.

The NY transmission system is studied, for regional reliability studies, using 90/10, 50/50 load base cases provided by NYISO. Performing more focused area transmission studies may require different load assumptions to capture the more severe operating conditions of the area:

For NYSEG, System Planning NY currently creates summer and winter forecasts using a linear regression of the most recent 10 years of summer and winter peak load data. These are updated annually. For RG&E, System Planning has kept data since 1975 and now has a log of 40 years of summer actual peak loads. Currently System planning is analyzing how many years give the best approach.

IUSA Sales & Load Forecasting group can currently provide Summer and Winter peak forecasts by Opco total only (not by Division). The forecasts are created in an econometric model based on 10 years of actual data with weather normalization and using average and high linear growth assumptions.

System Planning is comparing the different forecast methodologies and will work with Sales & Load to obtain data and develop Division forecasts. The objective is to have high-quality forecasts by Division and OpCo that are consistent with forecasts being used by other groups in IUSA NY.

5.5 Generation

5.5.1 Units Offline

Within Maine, to qualify a need under the ISO-NE "Needs Assessment" and "Solution Study," the two most impactful generators should be modeled offline and unavailable. For the local transmission system analysis only one unit may be modeled offline to show the need for system improvements, per Maine PUC "safe harbor" provisions. When one of the units being taken out-of-service is physically correlated to another unit, such as a combined cycle plant, removing the correlated generators is counted as one.

5.5.2 Renewable Generation output

Hydro

The hydroelectric generation in IUSA relies primarily upon the run-of-river flow to generate power. As such, these hydro facilities are classified as intermittent resources and therefore system studies should not rely upon their full capability. During summer months a reduced generation assumption should be applied that is derived from two or more years of historical metered data from the months of June through August. Utilizing this data, a flow duration curve will be calculated and the generation output that is exceeded approximately 85% of the time will be selected.

In addition to reviewing the summer expected output of hydro generation, the resultant high generation and low load during the spring should be analyzed. This scenario can create constraints on export and may require Corrective Action Plans. When conditions exist that create more severe conditions than study assumptions stated above, justification on the use of the conditions in planning the transmission system will be provided.

Wind

Using the same methodology for wind output as found to be a safe harbor for CMP's hydro dispatch in Docket 2011-494, the data shows a considerably high frequency of zero output for wind generators in CMP's territory. Therefore, the findings of this analysis support IUSA's recommendation to model wind generators at zero output during low generation dispatch conditions. Wind should not be relied on when studying load or system reactive support.

While the data from CMP wind output shows a low frequency of full nameplate output for the wind generators, modeling this higher output can be vital in determining the limitations of the system under full output conditions. This is especially true in heavy generation export areas. Therefore, analysis should be conducted using high wind generation output levels during studies as well.

5.6 Capacitor Design

a. The voltage flicker for installations after 2014 will be within the criteria of Section 3.2.2.
b. Whenever possible, switched capacitor banks shall be sized and operated in a manner that will minimize system losses and/or optimize the area power factor.
c. In most design situations, switched capacitor banks shall be equipped with automatic controls, typically with “CAP ON,” “CAP OFF,” Time Clock, Voltage Override, and time delay controls.
d. Switched capacitor bank control settings should be calculated to ensure proper operation under normal and first contingency conditions to minimize the need for intervention by operating personnel.
e. Whenever possible, switched capacitor banks shall be sized to avoid potential harmonic resonance during normal system operation, particularly at the 3rd, 5th, 7th, and 11th harmonics. This requirement does not usually apply to capacitor banks that are only used to provide voltage during first contingency conditions.

6 Transmission Interconnections

IUSA is governed by multiple procedures and criteria for transmission interconnections. Most of these procedures are coordinated with NERC and associated ISOs. Procedures are put into place governing FERC defined Large Generator and Small Generator (T-G), transmission to load (T-L) and transmission to transmission (T-T) interconnections. These procedures and processes are developed in compliance with NERC's FAC-001 and FAC-002 standards.

6.1 New York

Transmission Facilities owned by New York State Electric & Gas and Rochester Electric & Gas are governed by the NYISO procedures for interconnecting to the transmission system. Generators requesting to interconnect to the NYSEG & RG&E transmission system are directed to the NYISO so that they may follow NYISO's processes. Large Generator Interconnections and Small Generator Interconnections are governed by NYISO Open Access Transmission Tariff (OATT). Generators that interconnect outside the purview of NYISO are governed by the NYS Public Service Commission's Standardized Interconnection Requirements (SIRs). All generator interconnections processes also incorporate the NYSEG/RGE requirements document "Bulletin 86-01 Requirements For The Interconnection Of Generation, Transmission & End-User Facilities" in an open study process.

T-L and T-T interconnections are required to follow the NYSEG & RG&E document "Bulletin 86-01 Requirements For The Interconnection Of Generation, Transmission & End-User Facilities." All facility modifications to the NYISO jurisdictional transmission system must be done with an Interconnection Request application (IR) to NYISO. This ensures review by the ISO and study within the Regional System Plan.

6.2 Central Maine Power

Pool Transmission Facilities (PTF) owned by Central Maine Power are governed by the ISO-NE procedures for interconnecting to the transmission system. Generators requesting to interconnect to the CMP system are directed towards the ISO-NE processes. Large Generator Interconnections and Small Generator Interconnections are governed by ISO-NE Schedule 22 and Schedule 23 respectively. Generators that interconnect outside the purview of ISO-NE are governed by the MPUC Chapter 324. All generators interconnections impacting transmission incorporate the CMP requirements document "Transmission & Distribution Interconnection Requirements for Generation" in an open study process.

T-L and T-T interconnections are incorporated into the CMP requirements document "Requirements for Connection of Non Generating Facilities to The Central Maine Power Company Transmission System." All facility modifications to the ISO-NE jurisdictional transmission system must be done with a Proposed Plan Application (PPA). This ensures review by the ISO and study within the Regional System Plan.

7 Iberdrola USA Electric System Planning External Drivers

7.1 New York

On a biannual basis, as a means of being compliant with the NYISO Tariff and FERC Order 890, NYSEG and RG&E conducts a 10-year long term transmission system study. The results of the "NYSEG and RG&E Local Transmission Owner Planning Process and Results" study are then summarized and presented to the joint meeting of the Transmission Planning Advisory Subcommittee and Electric System Planning Working Group at the NYISO. The purpose of the 10-year study is to identify all of the long range system problems due to forced or maintenance outages that may occur on the NYSEG and RG&E transmission and sub-transmission systems over the next ten years and to recommend system reinforcements that would be required to correct these system problems. Those study results are also posted on the NYISO website.

All NY system upgrades are determined in accordance with Iberdrola-USA Electric Transmission Planning Criteria. Planning studies may result from:

- Periodic assessment of the NY local planning areas
- Load growth
- Retail or wholesale customer request
- Generator interconnection request
- System-wide contingency analysis

Studies utilize NYISO library base cases which are posted and retrieved by IUSA-NY system planners.

7.2 Maine

The Federal Energy Regulatory Commission (FERC) Order No. 890 directed all transmission providers with Open Access Transmission Tariffs (OATT) to adopt an open, transparent and fully coordinated transmission planning process. In compliance with Order 890, the participating transmission owners in New England developed and filed with FERC a new Appendix 1 – Local System Planning Process (Attachment K – Local or LSP Process) to the ISO New England, Inc Attachment K – Regional System Planning Process (Attachment K – Regional or RSP Process). The LSP and RSP processes are located in Section II of the OATT. Consistent with the responsibilities delineated in the Transmission Operating Agreement, the participating transmission owners have Section 205 rights over the LSP.

Attachment K – Local prescribes the local system planning process for the non-PTF (Pool Transmission Facilities) in New England for projects not already included within the Regional System Plan. Significant coordination is required between the ISO NE planning for PTF and CMP's planning for the non-PTF in Maine. To accommodate this coordination, ISO NE expanded the Project Advisory Committee (PAC) forum to allow an opportunity for CMP and the other participating transmission owners to conduct our own open stakeholder meetings to review LSP matters and LSP Project Lists.

On an annual basis, CMP complies with the Attachment K – Local requirements by performing a local system needs assessment and developing a Local System Plan and project list. This plan describes projected improvements to the non-PTF that are needed to maintain reliable customer service according to our local system planning criteria. The LSP is communicated to the PAC at an ISO NE PAC RSP meeting once a year. PAC, transmission customers, and other stakeholders have 30 days to provide written comments for consideration to CMP. The LSP project list is a cumulative listing of proposed solutions intended to meet identified needs. The LSP project list contains a status of each non-PTF project that follows the RSP convention:

Concept	Project is under consideration as a possible solution to a need, but little or no analysis is available
Proposed	CMP has determined that the project is an appropriate solution to a need, but has not yet obtained internal budget approval
Planned	Budgetary approval has been obtained
Under Construction	Project is approved and is under design/construction
In-Service	Project is complete

All CMP system upgrades are determined in accordance with Iberdrola-USA Electric System Planning Criteria. Planning studies may result from:

- Periodic assessment of CMP's 14 local planning areas
- Load growth
- Retail or wholesale customer request
- Generator interconnection request
- System-wide contingency analysis

Studies may utilize both ISO NE library base cases from Model on Demand (MOD) and/or local CMP base cases. Generator interconnections on the non –PTF transmission system are guided by the CMP Transmission and Distribution Interconnection Requirements for Generation manual.

8 Project Prioritization

Through the System Planning process, deficiencies are identified, solutions are developed and tested and projects are initiated based on the recommended solution. Once the recommended system reinforcements to the system problems have been identified, the IUSA System Planning department will prioritize projects utilizing the "Iberdrola USA Reliability Project Prioritization Methodology."

The prioritization process takes into effect:

1. Projects which are deemed to be mandated by a regulatory agency, external customer, safety rule regulation, standard violation, etc, receive the highest rank
2. Overloaded Projects. Equipment that has exceed its normal operating rating under normal system operations
3. Voltage problems under normal system operations
4. Reliability projects: N-1
5. Reliability projects: N-1-1

Then System Planning will utilize three separate metrics to compare and prioritize these recommended projects in each of the above categories. The three metrics used are as follows:

1) MW Load at Risk – the MW load at risk is determined by identifying the substation(s) that are affected by the given critical contingency or normal condition problem and quantify the amount of load that is supplied from the circuits out of affected substation(s).
2) Number of Customers at Risk – the number of customers at risk is determined by again identifying the substation(s) that are affected by the critical contingency or normal condition problem and quantifying the number of customers that are supplied from the affected substation(s).
3) Hours of Exposure – the hours of exposure are determined by analyzing a load duration curve for the study area. The hours of exposure are determined by identifying the critical load level at which there is a problem and then using the load duration curve to calculate the number of hours that the load level in the study area exceeds the critical load level.

When situations are identified that cannot be adequately served during certain forced or maintenance contingencies, selected areas of impact are evaluated and available resources are allocated in a manner that will maximize the benefit to NYSEG and RG&E customers. The variables evaluated in addition to the System Planning metrics can include, but are not limited to: the probability of the event occurring and its associated risk, the frequency and duration of the outage, the number and criticality of customers impacted, lost revenue, damage claims, and the cost of system upgrades.

IBERDROLA USA	**IBERDROLA USA TECHNICAL MANUAL**	**TM 1.61.00** Revision 01 Date : **08-2012**

DISTRIBUTION PLANNING CRITERIA

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00	03-30-2012	Issued for Iberdrola-USA Planning consolidation	Standardization Department.
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1. Introduction

The purpose of this planning criteria document is to provide guidance in identifying the need for distribution system improvements to ensure cost effective, quality, customer electric service. This planning criterion provides a valuable tool for distribution engineers to:

- Objectively identify the need for service improvement;
- Serve as a guide to develop solutions
- Assist in prioritizing budget recommendations
- Maintain a consistent approach throughout Iberdrola USA

Planning criteria allows the identification of developing problems and ensure that plans adequately address service requirements.

The short-term distribution-planning horizon is based upon the time necessary to implement a solution, typically eighteen to twenty-four months. Since many solutions to distribution system problems require modification or additions to substations and transmission lines, distribution engineers shall focus on a five-year planning horizon to ensure proper coordination with these long lead time projects. Also an area approach to the developing solutions must be used when addressing circuit problems. This ensures that proposed projects will be long lasting, least costly and most effective by evaluating all reasonable alternatives.

Failure to meet any one criterion can justify a system improvement. Some criteria, such as those dealing with safety, require a more immediate response and will take priority over other problems that may be deferred. The distribution engineer must evaluate each proposed project against the planning criteria and establish its priority.

The Iberdrola USA Distribution Engineering Department reserves the right to routinely amend any of these criteria at any time.

This document is broken down into the following subject areas:

- **Chapter 1 – Introduction**: will provide an introduction to the need and uses of this document
- **Chapter 2 – Tools**: will provide a description of the tools available to assist in the distribution system analysis
- **Chapter 3 – Description of the Distribution System**: will provide a description of the distribution system in each of the Opcos that make up IUSA
- **Chapter 4 – New Service Requirements**: will provide the service requirements for new customers
- **Chapter 5 – Distribution System Reliability Analysis**: will provide definitions of system reliability criteria and solutions for improving system performance
- **Chapter 6 – Distribution Planning Criteria**: will provide acceptable equipment, voltage, and operating limits of the distribution system.

- **Chapter 7 – Generation Connected to Distribution Systems**: will provide the rules and regulations that must be met to interconnect generation on the distribution system
- **Chapter 8 – Project Prioritization**: will provide a definition of the methodology used to prioritize recommended system improvements and betterments

2. Tools

2.1 CYMDist

CYMDist is a distribution system analysis software tool. It models electrical parameters on distribution circuits and allows the distribution engineer to simulate existing conditions on un-metered portions of the circuit and predict the affects of changes.

A CYMDist database includes all common equipment data including impedances of standard line construction types; voltage regulator, capacitor and step transformer characteristics; and source equivalent impedance data.

The input data files are imported into the CYMDist software and combined with the equipment database information to create a model representing the circuit to be studied. The software includes a *load allocation* function which allows input of data taken from metering points on the circuit head-end and any other points available and distributes kW and kVAr values for each load point which will let the circuit analysis results match the metered data. This distribution of load can be based on Nameplate kVA, kWh or Demand values at each transformer location. The result is a complete circuit model which simulates summer or winter peak loading for each circuit to be studied.

Simplified three phase models maybe used to evaluate n-1 modeling for tie point evaluation. This model will designate all single phase and two phase distribution lines and the associated load as nodes on the simplified three phase model.

Three basic types of analysis can be done from the circuit model:

Steady State Load Flow – Provides voltage at all nodes and current through all sections by phase. Also calculates power, phase angle, losses, alerts for thermal overload, and voltage limits.

Fault Calculation – Uses simplified methods to calculate available current for faults on all circuit sections or a detailed loadflow for a fault in a specific location with all quantities from the (listed above) available.

Motor Start Analysis – Uses simplified methods to calculate the maximum motor size which can be started at all line sections or a detailed analysis for starting of a motor at a specified location while limiting voltage dips

CYMDist is used in Distribution Planning to:

- Simulate high and low voltage situations and test potential solutions.
- Evaluate loading vs equipment rating for circuit elements
- Provide guidance in phase reconnection to facilitate load/voltage balancing
- Evaluate the effects of large load additions or changes.
- Evaluate alternative proposals for system expansion or upgrades
- Evaluate conditions for proposed switching operations
- Evaluate and minimize losses
- Assist with optimum capacitor placement
- Analyze fault conditions (N-1)
- Evaluate flicker from motor starting or other sources.
- Assist with protective device coordination in conjunction with ASPEN software or CYMTCC software.

2.2 CYMExtract

Input data for CYMDist analysis is provided by the CYMExtract application. This application takes data from SmartMap (GIS system), SAP, and other data sources and produces two files in a CYMDist compatible format.

Network data – This supplies the physical layout and connectivity of the circuit elements. It includes all major nodes, the length and construction characteristics of the connecting line segments and location and connection of switches, fuses/protective devices, capacitors and voltage regulators. Where information is available it also includes sizes/settings of these devices.

Load data – Based on distribution transformer locations in SmartMap, this provides a load object on all appropriate line segments. Each load object includes the phase connections, nameplate kVA of the transformer and the kWh usage and Demand load supplied by the transformer. The kWh and Demand values are the aggregate for all customers connected to the transformer. For customers with Demand metering, actual Demand values are supplied. For the remaining customers, the extract application estimates un-diversified Demand load by applying appropriate factors to the kWh usage values. At present, choices for Demand load include only summer peak and winter peak estimates.

It should be noted that no actual reactive VAR loads are extracted from the customer meter reading data in SAP. Lacking actual data to calculate overall circuit power factor, CYMExtract assumes a customer power factor of 92% for all customer loads.

2.3 CYMTCC

CYMTCC can be used in conjunction with CYMDist or as a stand alone application for distribution protection and fuse coordination. A review of Distribution protection and fuse coordination will be completed when ever circuit reconfiguration or block load addition or reliability concerns are suspected. Changes in equipment and load can be modeled in CYMDist. CYMDist and CYMTCC can analyze the circuit and coordination can be reviewed and revised as needed.

2.4 Other Distribution Analysis Tools

To simulate regulator and capacitor placement, the following distribution analysis tools are utilized:

EDaPT - for RG&E circuits only - EDaPT will show voltage performance under different loading conditions and line losses for various scenarios.

SynerGee distribution analysis software may be used when all the circuits and loading is modeled for the station bus. SynerGee has the same capabilities as EDaPT and CYMDist with the addition of the ability to optimize the capacitor position for either voltage performance and/or minimum losses.

The **Regulator Setting Spreadsheet** in Microsoft Excel.

CYMDist, EDaPT or SynerGee may be used with some experimentation to determine the best location. Either analysis tool simulates the response of the compensation controls.

3. Description of the IUSA Distribution System

3.1 Topology

Rochester Gas and Electric Corporation approximately 364,000 electricity customers in a nine-county region of approximately 2,700 square miles centered on the city of Rochester in upstate New York.

New York State Electric & Gas (NYSEG) serves approximately 872,000 electricity customers in an 18,000 square mile area of central, eastern, and western New York: approximately 40% of upstate New York. NYSEG operates more than 37,000 miles of power transmission and distribution lines and more than 440 substations.

Central Maine Power Company it serves approximately 606,000 residential, commercial, and industrial customers. The company's service area includes approximately 11,000 square miles in the southern and central areas of Maine. Nearly 90% of the state is forested with 230 miles of coast line and 3500 miles of tidal coast line. Its delivery system comprises approximately 23,249 pole-miles of distribution line, 1,290 miles of underground or submarine cable, and 366 substations.

The table below shows some overall statistics for the IUSA member operating company systems.

Overall Network Statistics by Operating Company

Company	Customers	Line Length (miles)	No. of Trans.	Total Trans. (MVA)	Service Area (sq. mi.)
Totals	1,831,636	58,659	1,867	29,511	30,339
RG&E	359,855	7,597	340	6,940	1,952
NYSEG	868,436	31,122	1,161	15,402	16,421
CMP	603,345	19,940	366	7,169	11,966

3.2 Voltages

The table below shows the number of circuits within the IUSA system by voltage.

Number of Circuits by Voltage

Company	1 - 10 kV	10 -33kV	>33kV	Total Circuits
RG&E	434	187	0	621
NYSEG	736	442	211	1,389
CMP	15	399	46	460

The next table shows the mileage of distribution lines in the IUSA system by voltage.

Circuit Mileage by Voltage

Company	1-10kv mileage	10-33kv mileage	33kv > mileage	Total Mileage
RG&E	2,527	5,070	0	7,597
NYSEG	11,207	11,770	8,145	31,122
CMP	13,906	5,623	411	19,940

3.3 Substation Schemes for new Distribution Substations

All new transformers must have a load tap changer (LTC). Non-LTC transformers will be used for special applications as necessary and this will be reviewed on a case-by-case basis.

All new transformers will be 10MVA or larger. However, in the lower load rural stations 5MVA size may be acceptable and this will be reviewed on a case-by-case basis.

Two standard distribution transformer sizes with 34.5 – 12.5/11/4.8 kV voltage rating shall be used:

3.11.a 10/12.5 (14) MVA at 55 C (65 C)

3.11.b 20/26/33 (37.3) MVA at 55 C (65 C)

3.11.c 5/6.3 (7) MVA will be occasionally used for specific applications

Two standard ratings for distribution transformer sizes with 230kV to distribution voltages or 115kV to distribution voltages shall be used:

3.12.a 30/40/50 (56) MVA at 55 C (65 C)

3.12.b 12/16/20 (22.4) MVA at 55 C (65 C)

Figure 1: 46-34 kV / 12-4 kV Example 1 (tie circuits)

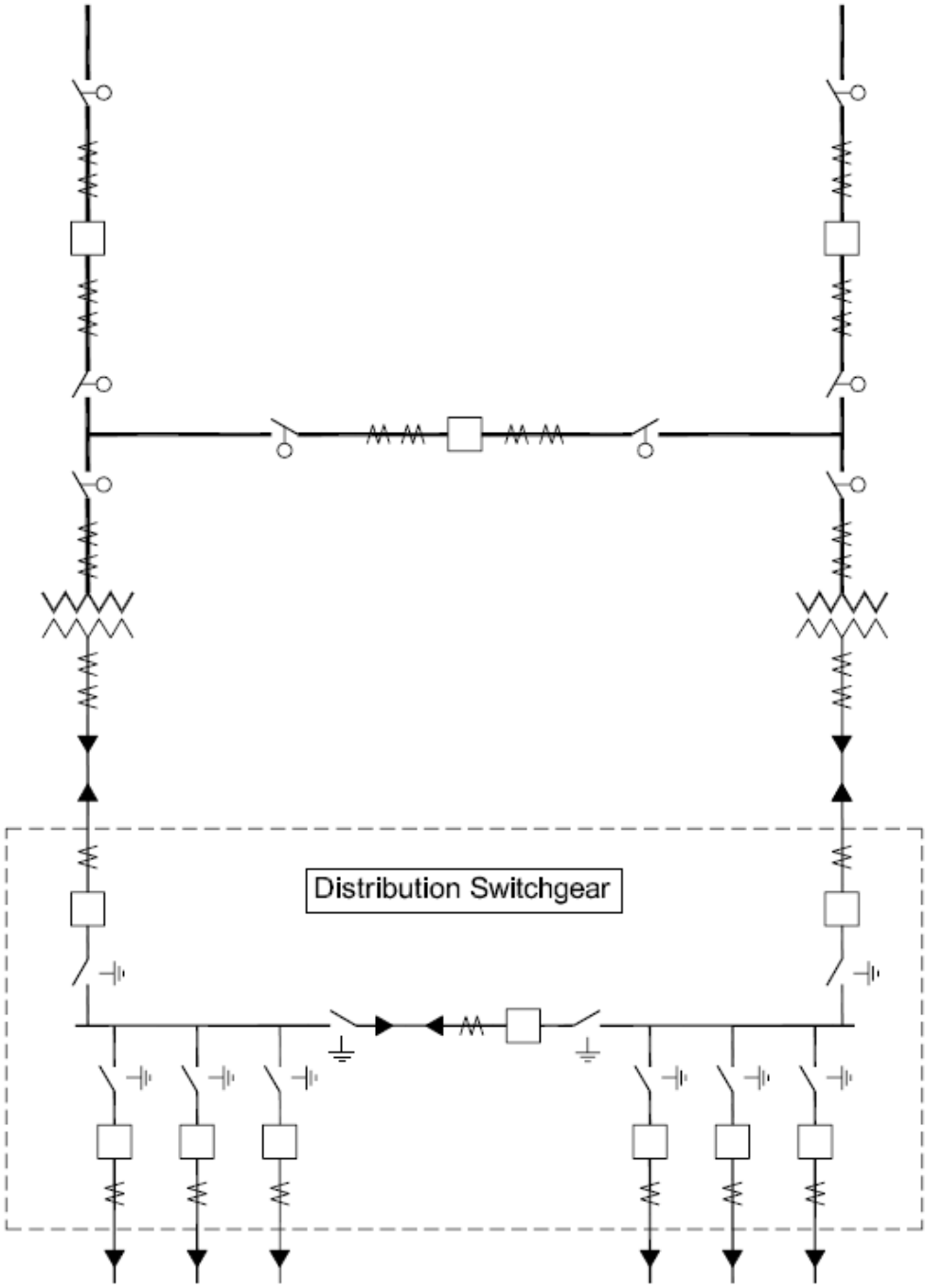


Figure 2: 46-34 kV / 12-4 kV Example 2

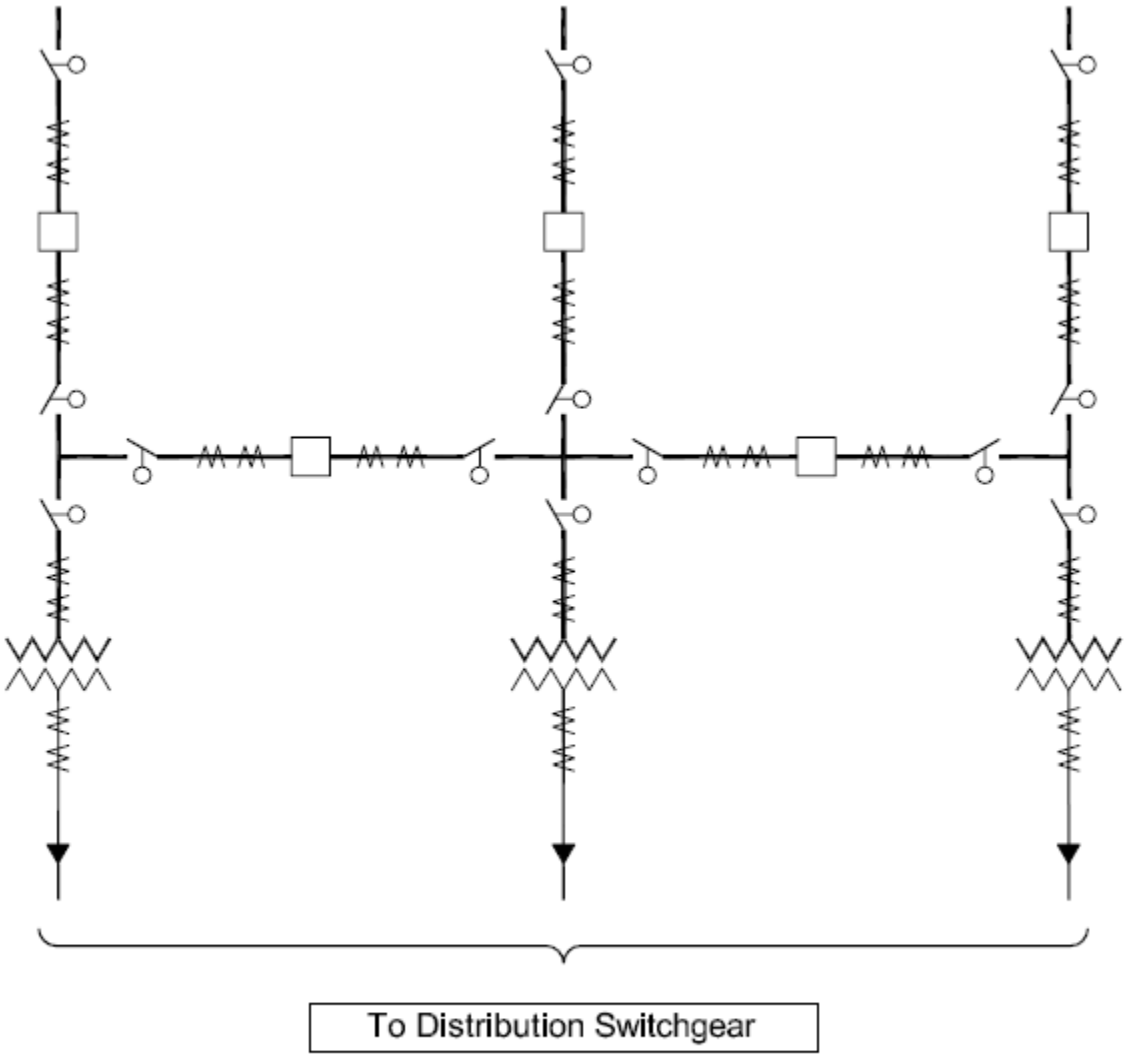
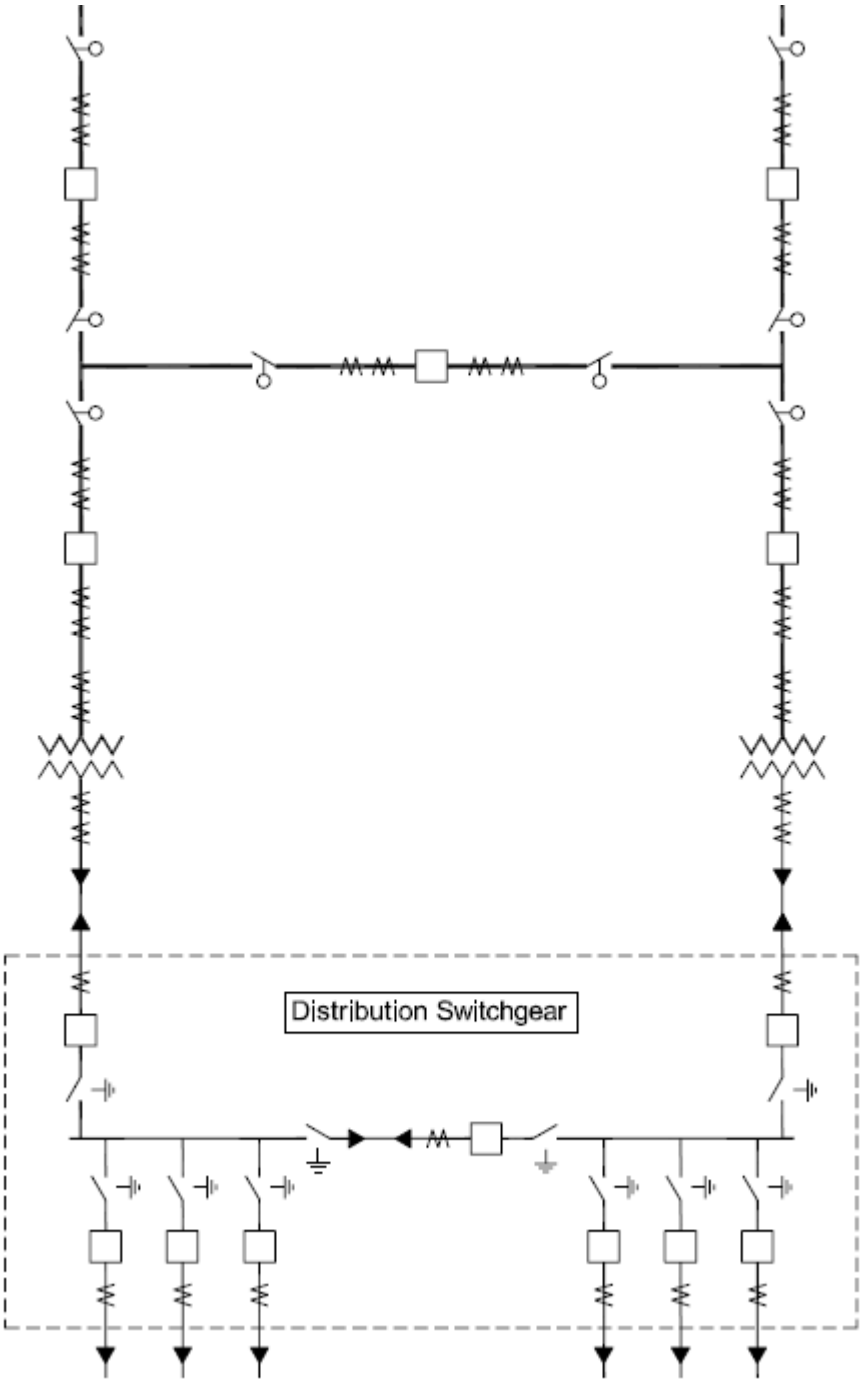


Figure 3: 46-34 kV / 12-4 kV Example 3 (circuit in and out)



3.4 Overhead versus Underground Criteria

As the cost of construction, operation, and maintenance of overhead electric distribution construction is less expensive, overhead electric distribution is the preferred method of construction at all IUSA Opcos. Underground construction is primarily used for areas required to be constructed underground due to tariff, order by a governmental authority having the proper jurisdiction or customer request as covered by the effective line extension policies of each IUSA Opco. The Companies may also elect to install certain facilities underground where congestion, right of way issues, or other factors beyond the Opco's control render overhead construction impractical.

4. New Service Requirements

Each IUSA operating company maintains a document outlining the requirements for new services and load additions. The requirements in each of these documents will be followed whenever new loads are connected to the distribution system.

Attachment 5 contains the new service requirements documents for each of the IUSA operating companies.

5. Distribution System Reliability Analysis

5.1 I-USA Reliability Goals

The reliability goals across all IUSA Opcos are standardized to the industry accepted reliability indices of customer average interruption duration index (CAIDI) and system average interruption frequency index (SAIFI). The CAIDI index represents the average time needed to restore service to the average customer per sustained interruption (an interruption greater than 5 minutes in length). It is the sum of customer interruption durations divided by the total number of customer interruptions as follows:

CAIDI = Sum total customer hours of interruption / Sum total of customers interrupted.

The SAIFI index represents the average frequency of sustained interruptions per customer over a predefined area. It is the total number of customer interruptions divided by the total numbers of customers served or connected as follows:

SAIFI = Sum total customer interruptions / Sum total customers connected.

These two indices are the primary measures of reliability performance at IUSA and are annually reported to the regulating entities. These indices are used in the establishment of the performance based rate structures of the IUSA Opcos and carry with them substantial monetary penalties for failure to achieve.

Given the importance of these reliability indices to the goals and objectives of the IUSA Opcos, it is incumbent upon the Distribution Engineer to thoroughly understand the manner in which system conditions and events affect the performance of these indices and their relationship to system improvement proposals. This knowledge must then be applied to their engineering analysis and subsequent recommendations for capital betterment projects so that their work will aide IUSA in the successful achievement of these important goals.

5.2 Worst Circuits

Distribution system reliability analysis will identify IUSA's worst performing distribution circuits and assess the reliability improvements that may be gained by decreasing the number of customers affected by single outage events, providing alternative sources, implementing automation schemes, and ensuring that circuits operate within operating limits.

Remedial action is required when Distribution Circuits are identified as one of the Worst Circuits for the individual operating Companies (See Attachment 2.). Worst performing circuits are selected using current year reliability data. The individual distribution circuit's performance is weighted against the performance of the specific operating company using the following formulas:

> % Weighted SAIFI = ((number of customers interrupted on the circuit/total number OPCO customers connected) / OPCO YTD SAIFI) x100
>
> % Weighted CAIDI = ((number of customer interruption hours on the circuit/total OPCO customer interruption hours) / OPCO YTD CAIDI) x100

The circuits are then ranked using these weighted values. These two lists are then used to select the worst performing circuits of specific operating areas for the annual reliability reports. The circuits contributing to 30% of the OPCO reliability performance are singled out for specific review and potential reliability improvement initiatives.

It is recommended that, for any customer experiencing twenty-four (24) recloser operations per year or more than four (4) per month, the distribution circuit shall be reviewed.

5.3 Customer Count

Customer counts per circuit should be limited to the following recommendations:

Planning Limit for Customers per Circuit

Company	Customer Count
NYSEG	2,500
RG& E	2,000
CMP	3,000

In addition, the following criteria will be applied to limit the number of customers affected by a single contingency:

- When the customer count per isolating device on any distribution circuit exceeds one thousand the circuit will be reviewed for further sectionalizing opportunities.
- Whenever two distribution circuits are fed from one distribution substation transformer, a tie capability should be provided at the substation.
- Any single contingency that would drop more than 2,000 kVA for longer than three hours not inclusive of storm will be reviewed.

5.4 N-1 Contingency Planning

All enhancements to the distribution system should consider peak loading levels (measured summer & winter loads) and normal system configuration compared to the Normal rating capacity limit of any substation or distribution circuit equipment. N-1 contingency planning will be required to provide for the failure of a system component and the reconfiguration to restore interrupted customers below the appropriate summer or winter Long Term Emergency (LTE) rating.

N-1 contingency planning consists of designing distribution circuits to supply the energy demand for normal conditions in case of a single element failure. When ever possible, circuit ties should be available to reconfigure the system to allow restoration of service to all customers affected by the equipment failure, with the exception of those located such that they cannot be sectionalized from the faulted equipment.

To provide N-1 contingency planning, the following criteria will be applied in distribution system reliability analyses:

- Distribution substation transformers and their circuits should be operated within their LTE rating during first contingency operations.
- Distribution circuits with adequate tie points and sectionalizing points available offer flexibility during first contingency operation. This provides the ability to restore as many customers as possible and isolate faulted line sections.
- For the loss of a single radial distribution circuit at a substation, appropriate ties may be available so that all the load of the faulted source can be transferred to other area circuits without exceeding their LTE ratings.
- For the loss of the transformer in a single transformer substation, when possible, radial circuits may be designed with tie capabilities to permit switching of all affected load to other area substations until a suitable mobile or spare transformer is installed. In cases where this is not possible, the outage will be minimized by the effective placement and use of tie and sectionalizing points.
- For two transformer substations (same distribution voltage), the total distribution coincidental peak load shall be no greater than the LTE Rating of the smallest substation transformer.

5.5 Distribution Automation Objectives

The vision for Distribution Automation at Iberdrola USA is to provide smart devices on all parts of the electric distrubution system. A system fully metered, monitored, and controlled provides integrated system operations, access for competing providers, and enhanced customer services that maximize benefits. A core element of this vision is that equipment purchases will only include devices that have full communications and control capabilities. All new distribution equipment will be "smart." IUSA also has a strategic plan to deploy digital Remote Terminal Units (RTUs) to provide for status and control of smart devices within substations and on the distribution system. In short, IUSA will continue to automate its entire system, consistent with all applicable standards and requirements. Another element of IUSA's vision is to upgrade its Energy Control Center (ECC) to manage the information and control capabilities on the distribution system. The upgraded, fully integrated ECC would consist of the following:

- Energy Management System (EMS);
- Supervisory Control & Data Acquisition (SCADA);
- Distribution Management System (DMS);
- Outage Management System (OMS) platform.

In order to plan for the coming technology and to avoid problems of early obsolescence and stranded cost on distribution equipment, the following plan for purchasing certain distribution equipment at Iberdrola USA (IUSA) is in effect:

- All distribution equipment controllers (recloser controls, regulator controls, load tap changer controls, capacitor controls) will be specified with communications capability.
- Fixed capacitor banks will no longer be purchased and switched capacitor banks will be utilized for future installations.
- Hydraulic reclosers will no longer be purchased and electronically controlled reclosers will be utilized for future installations.
- Network protectors will be specified with communications capability
- Pad-mounted switchgear controllers will be specified with communications capability.
- Motor operators for air-break switches will be specified with communications capability.

6. Distribution Planning Criteria

6.1 Equipment Loading Limits

6.1.1 Substation Transformers

In Maine, the transformer rating database (FacilityRatingDB.mdb), maintained by Substation Engineering, contains eight ratings for each distribution transformer within the substation.

- Summer Normal (SNORM)
- Summer Long Term Emergency (SLTE)
- Summer Short Term Emergency (SSTE)
- Summer Drastic Action Limit (SDAL)
- Winter Normal (WNORM)
- Winter Long Term Emergency (WLTE)
- Winter Short Term Emergency (WSTE)
- Winter Drastic Action Limit (WDAL)

In New York, the transformer ratings are developed and maintained by Substation Engineering using PTLoad Software from EPRI. In the event that transformer ratings are not available, the following table shows the transformer ratings to be used.

Transformer Ratings to be Used when Actual Ratings are not Available

Description	Normal		Planned Loading Beyond Nameplate		Long Term Emergency		Short Term Emergency	
	Sum.	Win.	Sum.	Win.	Sum.	Win.	Sum.	Win.
Ambient Temperature	30 C	5 C	30 C	5 C	35 C	10 C	35 C	10 C
In Degrees C & F	86 F	41 F	86 F	41 F	95 F	50 F	95 F	50 F
Pre-Load % Of Top Nameplate	100%	100%	70%	70%	100%	100%	100%	100%
Load Duration	24 hrs	24 hrs	8 hrs	8 hrs	4 hrs	4 hrs	15 min	15 min
Loss of Life			0.10%	0.10%				
Small Power <10 MVA	100%	115%	110%	130%	125%	140%	180%	190%
Medium Power 10 thru 99 MVA	105%	120%	115%	135%	130%	145%	200%	200%

Large Power 100 MVA and larger	110%	130%	125%	140%	135%	150%	150%	150%

These transformer ratings are used to plan, design, and operate the IUSA electric transmission and distribution system.

When a new distribution substation transformer is sized it is based on existing load with known customer block load additions, potential ties with adjoining distribution substations, long range plans for the area (future voltage conversions from 4.8 KV to 12.5 KV for example) and 5 or more years of projected load growth. This future load is then compared to the standard size transformers IUSA uses and the next size larger than the projected load is selected.

Substation transformers will be planned to the following load limits:

- **For two transformer stations** (same distribution voltage), the total distribution coincidental peak load shall be no greater than the LTE Rating of the smallest station transformer.
- **For single transformer stations, the t**ransformer loading should not exceed 100% of the Normal rating (65 C top nameplate rating).

The loadings above will take into account known block load additions and extraordinary load growth projections. By not utilizing single transformer ratings above nameplate values, the accommodation of future overloads by natural load growth is accounted for in the criterion.

6.1.2 Circuits

Distribution circuits are rated for load carrying capability by several factors. The nominal circuit rating is 400 amperes per phase based on standard distribution equipment used. The circuits are then up-rated or de-rated from this nominal value by the ratings of the actual equipment installed such as overhead conductor size, voltage regulator size, circuit breaker rating, recloser rating, relay settings, underground cable size, etc. One additional de-rating factor is the N-1 planned backup capacity that is reserved to allow available circuit ties to be utilized to restore power after a fault event.

Distribution circuit load information obtained from such sources as the monthly station charts and monthly manual station reads, as well as Summer/Winter Load Surveys to analyze the loading versus ratings.

6.1.3 Circuit Load Balance

Periodic review of distribution circuits for load balancing should be performed. A distribution circuit should be assessed for load balancing when the most heavily loaded phase exceeds the average phase loading by over 150%. (Reporting and processes to access this condition to be developed)

6.1.4 Conductors

Conductor loading shall not exceed the ratings in the IUSA construction standards.

6.1.5 Other equipment

Other equipment, such as voltage regulators, service transformers, and reclosers, will not be loaded above the nameplate ratings.

6.2 Voltage Limits

Voltage limits need to be evaluated at the substation bus, at any point on the primary circuit, and at the customer. Three limits must be maintained; Low Value, High Value, and Flicker Limit per the table below.

Voltage Limit Table

Limit	Customer	Primary	Bus
Low Value	114 V (-5%)	117 V	124 V
High Value	126 V (+5%)	126 V	126 V
Flicker Limit	3%	3%	3%
Balance	3% (N.L.)		
Voltage Harmonics	5% (P.C.C.)		

6.2.1 Voltage Regulation

No more than two line regulators should be placed in series on one circuit to correct for voltage problems. Each regulator in series requires a greater operating bandwidth with diminishing ability for effective voltage control.

Line regulators are added when regulation at the station and the application of capacitors is not sufficient to keep the circuit voltage profile within the prescribed limits. This is especially prevalent with lengthy circuits serving rural/suburban areas. They have also been used in instances where adjacent circuit ties are used often and voltage regulation when tied is a problem. Location of the regulators is based on the point at which the peak load voltage starts to fall below the minimum allowed. Settings and methods are similar to those for LTC transformers except that R and X settings may now be used appropriately since the regulator is controlling a single circuit.

To avoid a line regulator "fighting" the LTC or station regulation and causing excessive operations, the time delay is set to longer than the next source side regulation.

Digital controls support bi-directional regulation. In cases where bidirectional power flow is a possibility, a regulator with reverse power controls should be specified. It has been advantageous to provide different settings for each flow direction.

6.2.2 Voltage Balance

Electric supply systems should be designed and operated to limit the maximum voltage unbalance to 3 percent when measured at the electric-utility revenue meter under no-load (N.L.) conditions; in compliance with the American National Standards Institute (ANSI) C84.1 entitled "Electrical Power Systems and Equipment – Voltage Ratings (60Hz)". Appendix D, entitled "*Polyphase Voltage Unbalance*".

Voltage unbalance of a polyphase system is expressed as a percentage value and calculated as follows:

$$\text{Percent Voltage Unbalance} = 100 \times \frac{\text{(max deviation from average voltage)}}{\text{(average voltage)}}$$

Example: with phase-to-phase voltages of 230, 232, and 225, the average is 229; the maximum deviation from average is 4; and the percent unbalance is (100x4)/229 = 1.75 percent

6.2.3 Voltage Harmonics

The diverse nature of customers' electric loads supplied by IUSA transmission and distribution system results in the injection of harmonic distortion into the system**.** While in most cases, the effects of harmonic distortion on electric equipment at other customer locations is insignificant, certain customer equipment such as motors and transformers may be adversely affected. Therefore, harmonic distortion, in the voltage, at the Point of Common Coupling (typically at the service entrance) caused by customers loads shall not exceed 3% for any single frequency or 5% total harmonic distortion and shall not injuriously affect IUSA's equipment or its service to others. This criteria is in agreement with IEEE Standards No. 519 – IEEE Recommended Practices for and Requirements for Harmonic Control in Electrical Power Systems. It is recognized that reasonable engineering judgment must be used in the application of these limits to balance compliance costs against adverse consequences of excess harmonic distortion.

6.3 Power Factor Correction

Capacitors are added to flatten the circuit voltage profile, improve power factor and reduce losses. Fixed capacitors are applied first to provide a peak loading power factor of ~0.97 and where they do not cause light load voltage to exceed the desired limits. Three phase capacitor banks are generally available in 150 KVAR increments. A first cut for placement is to place a standard size capacitor at a point on a circuit segment representing 1/2 the maximum kVAr loading on the segment. The position would then be adjusted to provide the best voltage profile. The Engineer should also keep track of associated changes in line losses with the emphasis on minimizing them. The final location should be checked under light loading conditions to be sure there are no problems with high voltage.

A minor limitation to locating a capacitor is the affect of harmonic currents generated by customer nonlinear loads. These can cause excessive current flow and voltage distortions in some conditions. These situations are generally not known in advance of installing the capacitor and are generally found by power quality investigations. This may require relocating a capacitor. We have had only a handful of instances of this problem.

Switched capacitors are added when conditions of limited duration require additional kVAr on the circuit which would cause high voltage if left energized during lighter loading periods. Location and sizing must take into account, the voltage step caused when the capacitors switch. The distribution planner should try to keep this generally within the same flicker limits imposed on motor starts (less than 3% with max switching events no more than one per hour). Possible control options are: supervisory control, time clock, voltage, kVAr, zero crossing and temperature switching points as well as combinations of these parameters. The choice is based on the individual situation. Switched capacitor banks are located at least a couple of pole spans away from other capacitor banks to avoid excessive inrush. There have been limited cases of interaction between a switched bank and an unusual customer load. These are difficult to predict in advance and so are handled on a case-by-case basis.

6.4 Safety Standards

Distribution planning solutions shall ensure that the following metrics are met in all planning proposals:

- **Safety**: Violations of NESC, OSHA, IUSA Safety requirements or other applicable codes or standards shall be corrected.
- **Standards**: IUSA Distribution Construction Standards shall be followed.
- **Economic**: Projects shall be proposed and ranked using economic factors according to Section 12 Project Prioritization Method for IUSA.

6.5 Distribution Protection and Fuse Coordination

Distribution system protection equipment, such as reclosers, switches, cutouts, regulators, connectors, etc. shall not be loaded beyond the manufacturers' ratings. Review of Distribution protection and fuse coordination will be completed when ever circuit reconfiguration, block load addition, or reliability concerns are suspected.

6.5.1 Recloser Selection and Location

Reclosers in general offer several advantages:

- They can carry more load than the maximum ampere rating of a distribution class fuse (200 amps),
- They can clear temporary faults, including those beyond a line fuse, with out causing a permanent outage,
- They can provide full 3-Phase protection should a permanent outage occur
- Should the opportunity arise, they can be part of an automatic loop system between adjacent distribution circuits to provide an N-1 level of reliability.

Guidelines for the application of 3-phase reclosers are as follows:

- On a long 3-Phase line with numerous laterals with a history of temporary faults causing permanent outages.
- To meet the criteria of the maximum breaker relay reach, a fuse would be too small to carry the peak load
- On circuits with two long 3-Phase lines just outside the substation, a recloser can be placed on one line while the breaker covers the other line, reducing the number of customers exposed to a protective device operating.
- On the load side of a 34.5 KV grounded wye 3-Phase step transformer to get the full KVA capacity of the step transformer and act as a 'mini substation'.

6.6 Asset Management

IUSA recognizes the need to make infrastructure investments to provide safe and reliable customer service in an environmentally responsive manner. This includes an Asset Management program which will provide a systematic, sustainable and coordinated effort to optimally manage the life cycles of assets and their associated performance, risks and expenditures for the purpose of achieving the strategic planning principles.

The Asset Management Department at IUSA will develop an approach to safeguarding the goals and objectives of our business using Asset Management techniques outlined in the PAS 55 standard. This approach will incorporate the different optimizing factors such as risk, value, cost, performance and the associated cost/benefit of the results. In addition, it will ensure adequate provision is made for future requirements and obligations.

It is incumbent on the Distribution Engineer to remain current with the recommendations and policies issued by the Asset Management Department and ensure that they are incorporated into their engineering recommendations and capital betterment proposals.

6.7 Ferroresonance

Distribution engineers should be aware of ferroresonance and provide support to various areas of the company to help avoid the problem and to mitigate its effects should it occur. The increased connections of distributed generation (DG) to the system have brought more attention to ferroresonance issues. The distribution engineer assists in the technical review of proposed DG installations and supports the identification of the conditions that may lead to a ferroresonance situation. When developing distribution planning projects, attention to the conditions that may cause ferroresonance should be considered.

Corrective measures include:

- Use of three-phase switching devices;
- Keep transformers loaded during switching;
- Eliminate single phase fusing; and
- Decrease capacitance on the circuit.

7. Distributed Generation

This section is mainly concerned with generation facilities designed to operate in *parallel* with the utility electrical system. The majority of these installations are "net metered" and require bi-directional meters to measure the net amount of electricity supplied by the utility and provided to the utility by the generator.

The Standardized Interconnection Requirements and Application Process for New Distributed Generators are covered by the following documents:

> **New York**: Bulletin 86-01 Requirements for the Interconnection of Generation, Transmission and End-User Facilities (see *Attachment 2: NY Bulleting 86-01 Distributed Generation Technical Review Process*)
>
> **Maine**: Chapter 324 Small Generator Interconnection Procedures (see Attachment 3: *ME Chapter 324 Process Summary Process* and *Transmission & Distribution Interconnection Requirements for Generation*).

By tariff, all New York non-residential back-up generators need a 'Standard Backup Generator Letter Agreement' and a technical review of their interconnections. All applications for non-residential back-up generators are processed by the Project Manager, NUG Interconnections. IEEE Standard 1547 is used to classify the back-up generation as Open or Closed transition configuration. IEEE 1547 Standard applies when the closed transfer transition time exceeds 100msecs. Therefore, 100msecs is used as the trigger to treat a generator as paralleled, with all of the attendant checks and precautions, as if they were paralleled all the time.

8. Project Prioritizing Method for IUSA

Electric Distribution Engineering will use the following method to prioritize the capital projects proposed to Investment Planning for inclusion into the Iberdrola USA Capital Investment Plans:

Project Ranking Sheet

Mandatory Projects All projects which are deemed to be mandated by a regulatory agency, external customer, safety rule regulation, standard violation, etc. receive the highest rank	
If not Mandated, the following ranking will apply: **Overload Projects**	
All projects which are designed to replace equipment that has exceeded it's normal operating ratings will be ranked in a manner in which the equipment can be replaced in the current budget year or as soon as engineering, equipment procurement and construction scheduling permit. All projects which are designed to replace equipment that is projected to exceed it's normal operating ratings in a future year beyond the current budgeting year, will be ranked in a manner in which the equipment replacement is optimized within the expected year of ratings overload.	
Reliability Projects	
All reliability projects focused on the worst performing circuits or on other system Improvement work proposed to improve or enhance reliability performance shall be Ranked by ratio of total cost to total hours of customer interruption expected to be avoided upon completion of the proposed project.	
All Other Projects	

Attachment 1: CAIDI or SAIFI Circuit Review Summary Sheet

CAIDI or SAIFI CIRCUIT REVIEW

Circuit:			**Rank**	**WT**	**KV:**		**Ckt Miles:**	
		CAIDI			**PEAK KW**		**# CUST.**	
		SAIFI						
Device			SCADA Ctrl			Relay		

Outage Summary:

RGE			**NYSEG**			**CMP**			
Category	PSC CODE	Number	Category	PSC CODE	Number	Category	Number	# Cust.	CustHrs
Trees	2		Trees	2		Animal			
Animals	3		Overloads	3		Cable			
Equipment	5		Op. Errors	4		Equipment			
MVA	6		Equipment	5		Lightning			
Lightning	9		Accidents	6		Other			
Unknown	10		Prearranged	7		Planned			
			Cust Eq Fail	8		Structure			
			Lightning	9		Tree			
			Unknown	10		Unknown			
		0			**0**	Vehicle			
						Weather			
							0	**0**	**0**

OPTIONS:

External circuit ties/load transfers:
Internal circuit ties/load transfers:
New circuit/load split:
Automation, loop or radial:
Tree trim:
Equip. replacement:
Animal proof:
Lighning proof:
Infrared test:
SCADAMATE switches:

Rejected Options and why:

Recommended option(s):

(w/major equip & line miles)

Cost verses benefit table:

Option #	Reliability Project	CustHrs Saved	Capital Cost
1	Establish second circuit		

2	Install an RTU.			
3	New switches			
4	Upgrade substation breaker relays			
5	Loop #1			

Attachment 2: NY Bulletin 86-01 Distributed Generation Technical Review Process

This process is mainly concerned with generation facilities designed to operate in parallel with the utility electrical system. The purpose of the technical review is to verify the compatibility of the proposed equipment with the point of interconnection (POI) with the utility, identify any adverse system impacts that would result from the interconnection of the proposed equipment, and identify any system reinforcement work necessary to accommodate the proposed generator interconnect. The main focus areas of the Distribution Planner's review are, but not limited to:

- Steady State Voltage Control
- Voltage Flicker
- Fuse Coordination
- Thermal Equipment Loadings
- Compatibility of proposed generator installation equipment with the POI to the utility.
- Harmonics
- Ferroresonance
- Need for substation interval metering on the distribution circuit feeder.

The following steps are used by the Distribution Planning Engineers to conduct their portion of the project's technical review:

1. Identify the customer's location (substation, circuit, line, pole and service transformer). Review the technical data submitted by the customer to insure the cover sheet generator size is correct and complete.
2. Insure the service transformer is sized large enough to handle all potential back feed from the customer to the utility.
3. Verify that a disconnect switch for all generators larger than 25 kW and all non-inverter based systems of 25 kW or less has been included in the design package.
4. Do a search of the customer generator data base to determine the amount of generation presently on the circuit.
5. Determine if adding this unit will cause the total generation on the circuit to exceed 20% of the circuit equipment ratings (conductor, transformers, etc.).
6. Determine if there are line protective devices between the generator and the substation breaker, verify coordination and document.

Steps 7-14 are taken for larger generators (rated generation of 15% of total circuit capacity or greater) reference source; Dugan, Roger, *Electrical Power Systems Quality*.

7. Review the area for adjoining circuits with ties to the generator's normal circuit feed.

8. Prepare a one line diagram showing the normal and tie circuits the generator could potentially supply power into when connected.
9. Document the peak load flows and the positive and zero sequence impedances on the major line sections on the diagram.
10. Prepare a CYMDist circuit model and add the generator to determine possible steady state voltage control and thermal loading problems due to the generator's back feed.
11. Insure that all impacted voltage regulating devices are suitable for bi-directional power flow.
12. Verify that the voltage fluctuation at the POI is within acceptable limits when the generator facility parallels with and suddenly disconnects from the utility system.
13. In cases where the generation exceeds 20% of the limiting thermal capacity of the distribution system to which it is connecting, make recommendations for equipment and circuit upgrades necessary to accommodate the generator.

    Substation interval metering on distribution circuit feeders should be recommended for installation as part of the technical review process for all new distributed generators which exceed 20% of the limiting thermal capacity of the distribution circuit to which it is connecting. Smaller distributed generator installations may also require head-end interval metering when it is determined that their installation will significantly impact the native load of the circuit feeder. This head-end interval metering is needed to effectively model the impact of the generator on the circuit's native load subsequent to its connection to the system and during its life cycle of operation. The cost of this interval metering shall be borne by the generator unless otherwise determined by the Project Manager, NUG Interconnections.
14. Assist System Engineering in determining the ferroresonance risk brought on by the generator interconnection and document the current levels of capacitance connected to the distribution circuit.
15. Document all findings in a memo to the Project Manager, NUG Interconnections.

Attachment 3: ME Chapter 324 Process Summary

Effective January 2010, the Maine Public Utility Commission incorporated Chapter 324 as a required process for Maine Utilities to use for Small Generator Customers to interconnect to the utility system. Chapter 324 applies to interconnections that are NON-FERC jurisdictional only.

CMP created a WEB page specifically to allow interconnecting customer's access to download any required application forms or contractual forms, this page also provides a link to the MPUC site if further information is needed. The link is as follows: www.cmpco.com, go to your account, click on small generators and the information concerning the rules, application and contracts are provided.

Four levels were defined for interconnecting customers and the criteria are as follows:

Level 1:
No larger than 10kW
Inverter based
$50.00 application fee

Level 2:
Less than 2MW
$50.00 plus $1.00/kW application fee

Level 3:
No exporting of energy
10 MW or less
$100.00 plus $1.50/kW application fee

Level 4
All other interconnections not subject to FERC jurisdiction
$100.00 plus $2.00/kW application fee

CMP is only responsible for interconnecting customers within CMP's service territory.

CMP's established process for addressing Chapter 324 interconnections is as follows:

Level 1:

1. Contract Administration (CA) is the administrator for Level 1 interconnections and reviews these applications for completeness. We are allowed 5 business days for this process.
2. Once an application is deemed complete, CA sends it to the Interconnection Services Department (ISD) who has 10 business days to perform the technical screening based on the requirements of Chapter 324. If there are technical concerns for these interconnections, the application will be forwarded to the distribution-engineering group for further clarification.
3. Once the technical screening is complete, ISD will notify CA and CA will notify the customer if the technical screening has passed or failed.

4. If passed, CA will contact the metering group to order and install the proper metering. Metering Services will coordinate and install the proper metering for the project.
5. CA will notify the customer that the witness testing has been waived on level 1 application.
6. CA will send the CNEBA and I/A (Interconnection Agreement) to the customer to sign and return
7. If failed, ISD will inform the customer of the reasons for the failure and what the next step is, generally, minor changes are needed. If CMP needs to upgrade i.e. the transformer then CMP will invoice the customer for the necessary work to complete the interconnection. This invoice must be paid before CMP can perform the work. Once paid, CMP will complete the work required. The service Center will notify Distribution Engineering who will notify ISD.
8. Once the executed agreements are received back from the customer CA will execute the contracts and send an executed copy back to the customer and keep one executed copy in corporate records

Level 2

1. ISD is the administrator for Level 2 interconnections and reviews these applications for completeness. We are allowed 5 business days to do this.
2. Once the application is complete, technical screening is performed based on the requirements of Chap 324. We are allowed 15 business days to complete the technical screening. If there are technical concerns for these interconnections, the application will be forwarded to the following groups
3. For any protection or relay setting concerns, The Protection Relay group will be notified
4. For any other concerns, transformer configuration, circuit capacity, etc, the distribution group will address these concerns.
5. Once the technical screening is complete, ISD will notify the customer if the technical screening has passed or failed
6. If passed, CA will contact the metering group to order and install the proper metering. Metering Services will coordinate and install the proper metering for the project.
7. ISD will notify Contract Administration who will send the CNEBA and I/A to the customer to sign and return.
8. If failed, the customer by ISD will be informed of the reason for the failure and what they must do to remedy the issue. They will have the opportunity to resubmit the design to address the concerns. If the changes in our system are major*, the customer may be required to re-apply at a Level 4.

9. *Minor system changes are defined by the rule as less than 4 hours of work and $1,000 in materials. Everything else is considered a **major system improvement.**
10. Once the executed agreements are received back from the customer CA will execute the contracts and send an executed copy back to the customer and keep one executed copy in corporate records

Level 3

1. ISD is the administrator for Level 3 interconnections and reviews these applications for completeness. We are allowed 5 business days to do this.
2. Once the application is complete, technical screening is performed based on the requirements of Chap 324. We are allowed 17 business days to complete the technical screening. If there are technical concerns for these interconnections, the application will be forwarded to the following groups
3. For any protection or relay setting concerns, The Protection Relay Group will be notified
4. For any other concerns, transformer configuration, circuit capacity, etc, the distribution group will address these concerns.
5. Once the technical screening is complete, ISD will notify the customer if the technical screening has passed or failed
6. If passed, CA will contact the metering group to order and install the proper metering. Metering Services will coordinate and install the proper metering for the project.
7. ISD will send the I/A to the customer to sign and return.
8. If failed, the customer will be informed by ISD of the failure and what they must do to remedy the issue. They have the opportunity to resubmit the design to address the concerns. If the changes in our system are major*, the customer may be required to re-apply at a Level 4.
9. *Minor system changes are defined by the rule as less than 4 hours of work and $1,000 in materials. Everything else is considered a **major system improvement.**
10. Once the executed agreements are received back from the customer CA/ISD will execute the contracts and send an executed copy back to the customer and keep one executed copy in corporate records.

Level 4

1. ISD is the administrator for Level 4 interconnections and will review these applications for completeness. We are allowed 10 business days to do this.
2. Once the application is complete, the customer is notified and the study process will begin.

3. The interconnection customer's project may be is placed in a queue. The queue position is based on the date the application is considered complete. The customer will be assigned a queue number. This is only where there are overlapping projects that could influence each other during the study process.
4. Within 10 business days of notifying the interconnection customer the application is complete, we are required to have a scoping meeting with the customer. At the scoping meeting, and with mutual agreement between the customer and CMP, any or all of the required studies can be waived.
5. Within 5 business days of the scoping meeting, we shall provide the customer with a good faith estimate of the costs and time to undertake a feasibility study. This study shall provide a preliminary review of the potential impacts on the distribution system for the proposed interconnection. The customer must sign the study agreement and return to CMP. The feasibility study shall provide a preliminary review of short circuit currents, including contribution from the proposed generator, and coordination and potential overloading of distribution circuit protection devices. The feasibility Study shall be completed and the results transmitted to the customer within 30 calendar days after the parties execute the agreement.
6. ISD will contact the metering group to order and install the proper metering. Metering Services will coordinate and install the proper metering for the project.
7. Provided there are no violations found in the feasibility study, the Impact Study MAY be waived.
8. CMP may require a study deposit of the lesser of 100 percent of the estimated non-binding good faith study costs or $1,000.
9. Within 10 business days of completion of the Feasibility Study, we must send the Impact Study Agreement including a cost estimate to the customer for approval and execution, if it is not waived.
10. The Impact Study report shall provide the following information: Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection
    a. Identification of any thermal overload or voltage limit violations resulting from the interconnection
    b. Identification of any instability of inadequately damped response to system disturbances resulting from the interconnection
    c. Description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the T & D Utilities Electric Distribution System and to address the identified short circuit, instability and power flow issues. CMP may require a study deposit of the lesser of 50 percent of the estimated non-binding good faith study costs or $3,000.

d. The Impact Study must be completed and the results conveyed to the customer within 45 business days. CMP may utilize outside resources to perform this study work.

11. For minor modifications, within 5 business days of completion of the Impact Study, an executable I/A is to be sent to the customer which will include a quote and scope for the work needed to be done. This will be completed by the ISD.
12. For major modifications, within 10 business days of the completion of the Impact Study, a Facility Study Agreement will be sent to the customer will include a good faith estimate of the study cost. This will be completed by the ISD
13. Within 30 days of receipt of an executable I/A, the customer must sign and return the agreement. Agree upon milestones may be incorporated in to the I/A
14. Once the executed agreements are received back from the customer, ISD will execute the contracts and send an executed copy back to the customer and keep one executed copy in corporate records

For Levels 2, 3 and 4, CMP reserves the right to witness the interconnection commissioning tests. If an inspection is required, the Customer must provide at least 27 Business Days' notice to the T & D Utility prior to the initiation of operations.

Throughout the process, communication as to the status of the project and any issues that may arise is the responsibility of the CA and ISD to keep the customer informed as to the status of their project throughout the process and to assist them with any questions that they may have. .

DISPUTE RESOLUTION:

Disputes arising between the T & D Utility and the Customer Generator under this Chapter may be brought to the Maine Public Utilities.

Attachment 4: Sample 2011 Distribution Issues Workbook

G:\Documents\
Engineering & Deliver

Attachment 5: IUSA Requirements for New Service Connections

CMP Handbook of Requirements for Electric Service and Meter Installations

C:\Documents and Settings\conroyb\Des

NYSEG Electric Services and Meters: Specifications for Electric Installations

C:\Documents and Settings\conroyb\Des

RG&E Requirements for Installation of Electric Services and Meters

C:\Documents and Settings\conroyb\Des

NEW YORK INDEPENDENT SYSTEM OPERATOR

MANUAL 15

Emergency Operations Manual

July 2015

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Revision History

Version	Date	Revisions
6.21	**07/21/2015**	**Appendix Only Revision** **Table C.1** ➢ Updated Voltage Reduction Tables and Load Relief Tables **Table G.2** ➢ Removed DOE-417 form. ➢ Added hyperlink to online version of OE-417 form
6.20	**02/25/2015**	**Appendix Only Revision** **Table A.2, A.3** ➢ Updated to reflect the target voltage values and various pre-contingency low voltage limits and transfer combinations based on the study approved by the NYISO Operating Committee on 2/13/15 **Table A.6** ➢ Removed the West Central Interface as an IROL interface based on the study approved by the NYISO Operating Committee on 2/13/15
6.19	**07/18/2014**	**Appendix Only Revision** ➢ Table C.3 Updated column headers to more accurately represent the transmission locations
6.18	**07/07/2014**	**Appendix Only Revision** ➢ Table A.1Removed exceptions and referenced the NYSRC exceptions list **Table B** ➢ Removed Table B.1 as the updated version is CEII **Table C.1** ➢ Updated Voltage Reduction Tables and Load Relief Tables **Table C.3** ➢ Replaced the UPNY-SENY load relief table with the UPNY-CON ED table
6.17	**2/13/2014**	**Appendix Only Revision** **Table A.4** ➢ Updated to reflect the change in the Moses station exit tower configuration
6.16	**09/04/2013**	**Appendix Only Revision** **Table C.2, C.3** ➢ Updated title
6.15	**07/11/2013**	**Appendix Only Revision** **Table C.1**

		➢ Updated Voltage Reduction Tables and Load Relief Tables
6.14	**05/01/2013**	**Section 4.4** ➢ Revised description of SCUC function regarding Day Ahead forecast Operating Reserve deficiency
6.13	**6/12/2012**	**Appendix Only Revision** **Table A.4** ➢ Changed "on line MCE" to CA ➢ Removed Oakdale 32/36 TWR ➢ Updated the Hillside 68/69 to 72/69 TWR based on the addition of Stony Ridge station ➢ Added 2- 230kV/115kV towers based on what National Grid monitors. Dunkirk 68/160 TWR, Packard 61/191 TWR **Table A.6** ➢ Removed HQ-NY as a IROL limit based on Operations Engineering assessment **Table C.1-C.3** ➢ Updated to reflect the 2012 Load relief tables. **Table G.2** ➢ Updated the current version of the DOE-417 form. ➢
6.13	**11/1/2011**	**Sections 2.2, 3.2, 4.1** ➢ Revised to reflect NYSRC Policy No. 1-5 rule change PRR 108 ➢ Fraser SVC" in service" added to Table A.3
6.12	**7/13/2011**	**Table A.4** ➢ Designation and Terminal Changes **Table C.1** ➢ Updated Voltage Reduction Tables and Load Relief Tables **Table D.6** ➢ Company Information now required
6.11	**2/3/2011**	**Attachment A** ➢ Added new column for Millwood to Table A.3. ➢ Added Clarks Corners Rd (new station) to Table A.4
6.10	**09/08/2010**	**Attachment A** ➢ Updated to correct Table A.3.
6.9	**07/28/2010**	**Global** ➢ Revised external-document links to explicitly cite URLs from which documents may be accessed. ➢ Implemented minor stylistic and syntactic changes. ➢ Updated entity names as follows: • *Niagara Mohawk* and *NM* changed to *National Grid* and *NG*, respectively. • *Long Island Lighting Company* changed to *Long Island Power Authority (LIPA)*.

		• *Ontario Hydro* changed to *IESO*. ➢ Modified titles of personnel responsible for certain tasks to reflect changes in process/procedure, as appropriate. ➢ Updated terminology for clarification purposes, where appropriate, including changing *Control Areas* to *Reliability Coordinators* to indicate personnel. **Section 1.1** ➢ Incorporated material on "ISO Authority to Respond to Transmission Exceedance on Bulk Power System Transmission Facilities" from Technical Bulletin 163. ➢ Clarified that in relation to the policies addressed by this manual, non-specific references to NYISO personnel in the form of *the NYISO* should be inferred as meaning NYISO Power System Operators in the NYISO control room. **Section 1.2.2** ➢ Specified curtailment of interruptible load as being specific to Special Case Resources (ICAP and SCR) and Emergency Demand Response Programs (EDRP). **Section 1.2.3** ➢ Edited to indicate that self-scheduled fixed units are not exempt from responding to a reserve pickup 10-minute basepoint at their emergency response rates as bid. ➢ Deleted material related to "On Control with or without reserve control." **Section 1.3** ➢ Edited to indicate that he NYISO is required to notify federal and state government agencies, interconnected systems in the event of unusual operating conditions. **Section 1.3.1** ➢ Displaced existing content with new material on "Transmission Owner Emergency Notification," taken from Technical Bulletin 168, resulting in re-numbering of subsequent pre-existing subsections within section 1.3. **Section 1.3.2** ➢ Deleted references to the PSC Notification Book, instead referencing just the PSC Notification List. ➢ Changed "Operations Supervisor (or the NYISO Manager of Operations if the Operations Supervisor is unavailable)" to "NYISO Operations Management," in reference to required internal NYISO communications surrounding occurrence of unusual operating conditions. ➢ Eliminated references to the specific manner whereby NYISO personnel must supply to NYISO Operations Management information provided to the PSC. **Section 1.3.3** ➢ Added new material on "NYISO DOE Notification." **Section 1.3.4** ➢ Changed "media contact" to "NYISO External Affairs contact" in reference to required internal NYISO communications surrounding occurrence of system conditions that may result in general public awareness of an actual or impending situation. **Section 1.4** ➢ Removed Notification Book material, resulting in re-numbering of subsequent pre-existing subsections within section 1, with section 1.4 now focusing on Communications.

		Section 1.4.1 ➢ Remove material on communications restrictions between the NYISO and TOs subsequent to notification of an Alert or Major Emergency State. ➢ Remove material on communications restrictions between the NYISO and TOs subsequent to notification of a Restoration State. **Section 1.4.2** ➢ Specified new parameters for non emergency communications between the NYISO and TOs, eliminating constraint to extensions outlined in the Notification Book as well as references to the manner whereby calls will be transferred among NYISO staff. **Section 1.4.4** ➢ Eliminated material specifying the format and vehicle whereby NYISO staff shall disseminate emergency communications. **Section 1.5** ➢ Changed *NERC Security Communication Coordination System* to *NERC Reliability Coordinator Information System*. **Section 1.5.1** ➢ Added material on NYISO Emergency Hot Line communication protocol. ➢ Eliminated obsolete material outlining specific method of transferring to the stand-by telephone circuit if loss of communications occurs during a conference call. **Section 1.5.3** ➢ Changed required parameter for testing the conferencing capability of the ACC Emergency Hot Line from monthly to weekly. ➢ Removed material citing the Notification Book as being the source containing the telephone numbers designated by the TOs for the ACC Emergency Hot Line. **Section 1.5.4** ➢ Updated to reflect the name of the system that the Reliability Coordinators use to post messages and share operating information in real time as being the Reliability Coordinator Information System (RCIS). **Section 2.2** ➢ Updated to reflect expanded Alert State Criteria related to Pre-Contingency (Actual) Flow, Post-Contingency Flow, Reserves, and NYISO IROL stability limit. **Section 2.3** ➢ Eliminated material outlining specific means via which the NYISO shall shift or start generation in order to obtain additional reactive power (MVAr) control. ➢ Reworked material on NYISO actions in responding to Alert States, particularly with regard to curtailment, ordering generation to Upper Operating Limit Emergency (UOLe), purchasing Emergency Energy from neighboring Reliability Coordinators, and activating Special Case ICAP (SCR) and EDRP Resources. ➢ Added material on TO actions in responding to Alert States, particularly with regard to disconnecting an affected facility in the face of an overload on a the facility or persistence of an abnormal voltage or reactive condition that endangers equipment. **Section 3.2** ➢ Updated to reflect expanded Major Emergency Criteria related to Pre-Contingency (Actual) Flow, Post-Contingency Flow, and Reserves.

		Section 3.3 ➢ Reworked material on NYISO actions in responding to Major Emergencies, particularly with regard to curtailment, ordering generation to Upper Operating Limit Emergency (UOLe), purchasing Emergency Energy from neighboring Reliability Coordinators, and activating Special Case ICAP (SCR) and EDRP Resources. ➢ Added material on TO actions in responding to Alert States, particularly with regard to disconnecting an affected facility in the face of an overload on a the facility or persistence of an abnormal voltage or reactive condition that endangers equipment. **Section 4.1.1** ➢ Added definition of Emergency Transfer Criteria (ETC) **Section 4.1.2** ➢ Specified time frames within which corrective action must be taken to restore STE and LTE ratings post-contingency as 5 and 10 minutes, respectively. **Section 4.1.3** ➢ Added "neighboring TOs" as among the entities the NYISO shall coordinate with if a potential overload condition in non-secured facilities cannot be corrected within 30 minutes of the initial violation. ➢ Specified *UOLe*, as opposed to *full operating capability*, as the level to which the NYISO may order generation in the face of a potential overload condition of non-secured facilities. ➢ Eliminated reference to the NYISO Outage Coordinator attempting to avoid scheduling outages that might result in conditions wherein the security of the non-Secured Facilities may become jeopardized. **Section 4.3** ➢ Changed main heading to include *IROL* so that it reads *Post-Contingency Voltage IROL Exceedance*. ➢ Updated subheadings to reflect thresholds of *Greater Than 100% But Less Than 105%* and *105% or Greater*. ➢ Added material relative to NERC standards IRO-005-2-R3 and TOP 007-0-R2. **Section 4.4** ➢ Reworked material on NYISO actions in responding to a Shortage of Operating Reserve in Day-Ahead Forecast, particularly with regard to the following: • Eliminated as an action determining whether energy associated with external energy sales by NYCA ICAP providers as NYISO Operating Reserve is of sufficient quantity to eliminate the deficiency. • Specified that Market Participants to be prepared for "the potential dispatch to UOLe" as opposed to "a maximum generator capability alert." • Clarified the source for information on initiating an Emergency Energy Alert as being NERC Standard EOP 002 and the means of doing so as being the Reliability Coordinator Information System (RCIS). • Changed means of counting load relief that can be implemented within 10 minutes. **Section 4.4.1** ➢ Displaced existing content with new material on " Shortage Operating Reserve New York City– Day-Ahead Forecast," resulting in re-numbering of subsequent pre-existing subsections within section 4.4. **Section 4.4.2**

		➢ Reworked material on NYISO actions in responding to a Shortage of Operating Reserve in Day, particularly: • Specified that Market Participants to be prepared for "the potential dispatch to UOLe" as opposed to "a maximum generator capability alert." • Clarified the source for information on initiating an Emergency Energy Alert as being NERC Standard EOP 002 and the means of doing so as being the Reliability Coordinator Information System (RCIS). **Section 4.4.3** ➢ Updated the name of the programs used to monitor the total Operating Reserve in real time from *Real-Time Dispatch* to *Reserve Monitor*. ➢ Eliminated counting external ICAP available as a measure to be taken in the event of a shortage of operating reserves in real time. ➢ Added new material on "Following a Contingency" and "A Non-Contingency Based Shortage." ➢ Expanded to include additional measures taken when declaring an alert state in the event of a deficiency in 10-minute reserves in real time. ➢ Edited to specify that in the event of a Major Emergency Declaration in relation to a shortage of operating reserves in real time, Market Participants are to be notified by TOs that the NYISO is dispatching to UOLe and that Market Participants are to follow basepoints in addition to making all generator capability available. ➢ Eliminated recalling external energy sales made by NYCA ICAP providers as a measure to be taken in the event of a Major Emergency Declaration in relation to a shortage of operating reserves in real time, specifying instead that an Emergency Energy Alert is to be initiated in accordance with NERC standard EOP 002-2 Attachment 1 via the RCIS; NPCC notification requirement (C-19) is to be followed; and NYISO Communications ,PSC, DEC, Gas Pipelines, and the Department of Energy(DOE) are to be notified via form OE 417. ➢ Eliminated count the load reduction available from quick response voltage reduction as 10-minute reserve and attempting to purchase emergency energy from sources outside NYISO as measures to be taken in the event of a Major Emergency Declaration in relation to a shortage of operating reserves in real time. **Section 4.4.4** ➢ Specified NERC Standard EOP 002-2 as the reference source for declaring an alert state in the event of a shortage of meeting Load (including the inability to reach a “0" ACE) in real time. ➢ Added notifying gas pipelines via e-mail as a measure to be taken when declaring an alert state in the event of a shortage of meeting Load (including the inability to reach a “0" ACE) in real time. ➢ Edited to specify that in the event of a Major Emergency Declaration in relation to a shortage of meeting Load (including the inability to reach a “0" ACE) in real time, Market Participants are to be notified by TOs to go to UOLe limits and follow basepoints in addition to the fact that the NYISO is in a generation alert. **Section 4.5** ➢ Changed main heading to include *IROL* so that it reads *IROL Stability Limit Violation*. ➢ Updated subheadings to reflect thresholds of *Greater Than 100% But Less Than 105%* and *105% or Greater*. ➢ Added material relative to NERC standards IRO-005-2-R3 and TOP 007-0-R2. **Section 5.1**

		➢ Edited to reflect that voltage criteria in relation to reducing transmission flows is of IROL designation. ➢ Changed *normal maximum levels* to *Upper Operating Limit Normal (UOLn)* levels in clarifying the applicable upper threshold to which the NYISO shall request voluntary shifts in generation to help relieve the violation. ➢ Removed reference to the *NYISO Transmission and Dispatching Operations Manual* as being the source of transaction curtailment procedures. **Section 6.0** ➢ Completely reworked to provide greater detail. **Section 7.2** ➢ Changed entities that the NYISO must direct to implement load relief procedures in the event of ongoing 10-minute reserve shortage following initiation of Quick Response Voltage Reduction from *the deficient company or companies (if known)* to *the TOs*. ➢ Eliminated requirement that TOs direct other member companies having quick response voltage reduction capability to reduce voltage up to 5%, or more if available. ➢ Eliminated requirement that NYISO staft must direct TOs to activate quick response voltage reduction previously withheld as required to match load generation to relieve facility overloads in the event that. NYISO resources are less than the NYCA load or NYCA facilities are above ratings or limits. **Section 7.3** ➢ Edited to reflect that NYISO orders rather than requests load shedding. **Section 7.5** ➢ Edited to reflect that NYISO orders rather than requests load shedding. **Section 8.2** ➢ Eliminated language regarding National Grid having to coordinate through NYPA for Hydro Quebec – NYPA contracts. **Section 8.3.2** ➢ Removed material citing the Notification Book as the source of NYISO Operations Management Staff member to be notified by NYISO personnel in the event of PCC evacuation after normal business hours ➢ Specified Fax as the sole means of providing the Security Monitor display to Consolidated Edison and National Grid in the event of PCC evacuation. ➢ Removed NYISO Net Interchange Summary and NYISO Generation Summary from the list of items to be provided to Consolidated Edison and National Grid in the event of PCC evacuation. ➢ Removed keys to the ACC as an item that NYISO staff must take to the ACC in the event of PCC evacuation. ➢ Updated list of entities that NYISO shift staff must notify in the event of PCC evacuation as being PJM, IESO, ISO-NE, and HQ. **Section 8.4.1** ➢ Clarified that DNI to be followed by TOs during initial interim NYCA operation is determined by NYISO Real-Time Dispatch (RTD) as opposed to Security Constrained Dispatch. ➢ Updated list of neighboring control areas for which NYISO must record DNI on the DNI Change log in the event of initial interim NYCA operation. **Section 8.4.2** ➢ Updated list of entities that Consolidate Edison staff must relay notices of solar magnetic disturbances during continuing interim NYCA operation as

		being ISO-NE, National Grid, and Consolidated Edison's respective TOs. **Section 8.5.1** ➢ Updated NYISO actions with regard to ACC operation as follows: • Removed reinitializing load trending. • Removed switching system frequency to an alternate source. • Updated list of entities that NYISO staff must notify that the ACC is operational and with whom NYISO staff must verify schedules. **Attachments** ➢ Added notes clarifying that attachments do not require committee approval and are subject to change at the NYISO's direction. **Attachment A** ➢ Removed Table A.1, resulting in re-numbering of subsequent tables within Attachment A. ➢ Changed *NYRSC* to *NYSRC* in Table A.1. ➢ In Table A.2, changed Pre Low Bus Voltage Limits for Dunwoodie 345, Millwood 345, and Pleasant Valley 345 to *348*, and added new footnote regarding Sprainbrook 345. ➢ Updated multiple terminals in 335HTable A..2. ➢ Added new Table A.6, IROL Interfaces, and Table A-7, Under Frequency Load Shed (UFLS) Implementation Plan. **Attachment B** ➢ In Table B.1, deleted text reading "Prompt restoration of the NYISO total customer load is best accomplished by the restoration of the NYS Power System. Although some customer load may be picked up during this procedure to maintain stability and voltage levels, priority must be assigned to the restoration of the major transmission ties. Each TO may restore load within its area in accordance with its own restoration plan, but load restoration must not delay the restoration of inter-and intra-Control Area ties." ➢ In Table B.1, deleted TO actions in reference to restoration procedures, replacing instead with update NYISO actions. **Attachment C** ➢ Deleted reference to obsolete Attachment C-4. **Attachment D** ➢ To the list of statements the NYISO Shift Supervisor should make when initiating emergency procedure testing, added one regarding confirmation of the procedures as tests. ➢ In relation Table D.4, changed reference for system restoration procedures to the *NYISO System Restoration Manual*. **Attachment E** ➢ Under *Transfers*, changed *OH – NY* to *IESO – NY* and changed *NE – NY* to *ISO-NE – NY* **Attachment G** ➢ Add new 336HTable G.2, 337HReporting to the DOE 417 (referenced in Technical Bulletin 168).
6.8	**07/28/2010**	**Attachment C** ➢ Updated Table C.1 for Summer 2010.
6.7	**05/14/2010**	**Attachment A** ➢ Updated Table A.2,

6.6	**08/12/2009**	**Attachment C** ➢ Updated table C-1 to reflect modified amounts of relief Long Island and Con Edison can obtain from load reduction.
6.5	**06/29/2009**	**Attachment C** ➢ Updated tables C-1, C-2, and C-3 for Summer 2009.
6.4	**09/04/2008**	**Global** ➢ Reformatted per new template to standardize presentation ➢ Standardized labeling and numbering of tabular material **Copyright Page** ➢ Implemented minor stylistic changes **Revision History Table** ➢ Changed column headings as follows: • Changed“ Revision” to “Version” • Changed “Changes” to “Revisions” ➢ Standardized date format to mm/dd/yyyy. ➢ Implemented minor stylistic changes in entries **Attachment A** ➢ Updated Table A-2 to reflect Exceptions to the NYSRC Reliability Rules
6.3	**06/27/2008**	**Attachment C** ➢ Updated tables C-1, C-2, and C-3 for Summer 2008.
6.2	**08/03/2007**	**Attachment C** ➢ Updated tables C-1, C-2, and C-3 with the numbers for Summer 2007. ➢ Removed table C-4.
6.1	**04/15/2005**	**Section 4.1.3** ➢ Deleted references to “Bulk Power System” and replaced with “Secured” ➢ NYISO was added before all acronym instances of SS (Shift Supervisor). **Section 6.1** ➢ Added text after 4th paragraph “During the Restoration State, the ISO may reserve blocks of generation for incremental deployment up to 700MW of generation capacity to facilitate restoration of the Con Edison NYC area 345kV transmission path from Sprainbrook/Dunwoodie substations to Freshkills substation.” **Attachment B** ➢ B-1 Restoration Procedures and Diagrams • Added paragraph between 1st and 2nd bullet of the first paragraph “The NYISO shall direct the Transmission Owners (TOs) to carry out their assigned steps…”
6.0	**11/11/2004**	**November 11, 2004** ➢ All Sections • Changes to reflect SMD2 – Throughout the document-All references to SCD changed to RTD, Pool Control Error (PCE) changed to Area Control Error (ACE), Designated Pool Coordinator to Designated NYISO Coordinator, and Security Constrained Dispatch to Real-Time Dispatch. • Reformatted document • Changed all instances of ISO to NYISO • Deleted all instances of the word, “Exhibits”

		• Updated grammar and spelling • Updated acronym usage • Added section 4.1.3.-Procedure for Relief of Potential Overloads on Non-Bulk Power System Facilities • Added section 7.4.Load Shedding During System Restoration ➢ Section 1.2.3 • Added this new section. Transmission Outage Scheduling section and accompanying text (TCC notification provisions). • Removed Off-Dispatch with and without reserve award. ➢ Attachment E • Deleted “MDS Sample Screens” and replaced with “Data Collection Forms”
5.0	**04/01/2004**	**Changes Inserted April 1, 2004** ➢ Complete Format Change. **Changes Inserted May 22, 2003 (Board approved 3/18/04)** ➢ Section 4.4.1 • #5 deleted “and Emergency Demand Response Program (EDRP)” • #6 Added “Count expected Emergency Demand Response Program (EDRP) as NYISO Operating Reserve and determine if it is of sufficient quantity to eliminate the deficiency.” • Renumbered paragraphs • #9 deleted “”and EDRP resources” • • #10 Added “Notify the appropriate Market Participants to prepare to make the EDRP resources available for the next day.” • After #12 Change numbers to bullets ➢ Section 4.4.2 • #5 deleted “and Emergency Demand Response Program (EDRP)” • Renumbered paragraphs • #5 deleted “and Emergency Demand Response Program (EDRP)” • Added #6. “Notify NYISO Special Case Resources (ICAP) that they are counted toward NYISO Operating Reserves, and may be required to be activated during a specified period of time. (Estimated start and end time as announced.)” • Added #7. Count NYISO Emergency Demand Response Program (EDRP) as NYISO Operating Reserves. • #8 deleted “NYISO Special Case Resources (ICAP) and” and deleted “as NYISO Operation Reserves that they may be required to be activated during a specified period of time. (Estimated start and end time announced.) Added “that they are counted toward NYISO Operating Reserves, and may be requested to be activated during a specified period of time. (Estimated start and end time as announced.)” • #12 deleted “Emergency Demand Response Program (EDRP)” and Added “Special Case Resources (ICAP).” • #13 Added “Direct Market Participants to activate Emergency Demand Response Program (EDRP) to start at XXXX hrs and end at XXXX hrs.” ➢ Section 4.4.3 • 1st para. Added “real-time” and “count external ICAP available, Special Case Resources (SCR) and Emergency Demand Response Program (EDRP).” Added “to”. • Removed numbering from 1st para. • Renumbered from 2nd para. • Deleted “Notify the appropriate Market Participants to activate NYISO Special Case Resources (ICAP). Activate Emergency Demand Response Program (EDRP), if possible. • Added “2. Notify the appropriate Market Participants to activate NYISO

		Special Case Resources (ICAP) if possible." And added "3. Notify the appropriate Market Participants to activate NYISO Emergency Demand Response Program. ➢ Section4.44 • 4th deleted "Activate Emergency Demand Response Program (EDRP)." • Added "Notify the appropriate Market Participants to activate Emergency Demand Response Program (EDRP), if possible. • Renumbered paragraphs. ➢ Delete from Revision History (May 29, 2001) • Sect 4.4.3 – delete "10-minure non-synchronized" and add "30-minute". Delete "10-minute synchronized" and add "10-minute." ➢ Delete from Revision History (Sept 12, 2000) • Sect 2.2 – delete "and" and add "Operating". Delete "Condition (2) is in effect." Add "Deficient." • Sect 2.3 – add "Order" and delete "may be ordered". Add "to full Operating capability" and delete "o" and "at normal response rates". • Attach A, Exh 1- Added "or equal to" after Frequency is greater than. Added "is sustained at that level or continues to increase" after 60.05 Hz and. Added "less" after "Frequency is". Added "or equal to" after "than". Added "5" after "59.9". Added "and is sustained at that level or continues to decline." After Hz.
4.0	**11/11/2001**	**Changes Inserted November 11, 2001** ➢ Sect. 4.4.1 • First paragraph - delete "ICAP" • First paragraph - after "external energy sales" insert "from NYISO ICAP providers" • #3, delete "external ICAP purchases" and replace with "energy available from external NYCA ICAP providers" • #3, delete "purchases" and replace with "providers" • #4, delete "ICAP exports from NYCA to other control areas" and replace with "external energy sales by NYCA ICAP providers" • #5, delete "special ICAP customers" and replace with "Special Case Resources (ICAP)" • #8, delete "special case ICAP" and replace with "Special Case Resources (ICAP) and" • #8, after "EDRP" insert "resources" • #9, replace "Subsection " with "Subsection 1" ➢ Sect. 4.4.2 • #3, delete "external ICAP purchases" and replace with "energy recallable from external ICAP resources" • #3, delete "associated with these ICAP purchases" and replace with "available from external NYCA ICAP providers" • #4, delete "ICAP." After "control areas" add "by NYISO ICAP providers" • #5 and #6, delete "special ICAP customers" and replace with "Special Case Resources (ICAP)." ➢ Sect. 4.4.3 • # 4, delete "ICAP" and replace with "external." At the end add: "provided by NYCA ICAP providers" • #5, delete "special ICAP customer" and replace with "Special Case Resources (ICAP)" ➢ Sect 4.4.4 • #3, delete "ICAP" and replace with "external." At the end add: "provided by NYCA ICAP providers." • #4, delete "ICAP Customer" and replace with "Case Resources"
3.1	**08/08/2001**	**Changes Inserted August 2001**

		➢ Global Change • "Special" should change to "Special Case" throughout the entire manual. ➢ Sect. 2.3 • Change to "Direct the TOs, via hotline, to prepare to curtail non-essential company loads for next day and to notify appropriate Market Participants to prepare to curtail nonessential company load for the next day." ➢ Sect. 3.3.1 • Insert after the existing (L): "Direct the TOs, via hotline, to prepare to curtail non-essential company loads for next day and to notify appropriate Market Participants to prepare to curtail non-essential company load for the next day." • Insert before the existing (L): "Activate Special Case ICAP and EDRP resources." ➢ Sect. 4.4.1 • # 8: Change to "Notify the appropriate Market Participants to prepare and make special case ICAP and EDRP available for the next day." ➢ ➢ Sect. 4.4.3 • # 5: Change to "Notify the appropriate Market Participants to activate NYISO special ICAP customer. Activate Emergency Demand Response Program (EDRP), if possible." ➢ Sect. 4.4.4 • #4: Change to: "Notify the appropriate Market Participant to activate NYISO special ICAP customer. Activate Emergency Demand Response Program (EDRP), if possible."
3.0	**05/29/2001**	**Changes Inserted May 29, 2001** ➢ Sect. 2.2 • Renumber list so that it runs continuously starting from beginning at number 1. • #11 (Old #9) insert "A" at beginning of sentence. • #12 at end of sentence add: "Operating Reserve Deficient." • #13 delete "13. An actual operating reserve deficiency exists." ➢ Sect. 2.3 • 1st sentence: delete "Shift Supervisor" after "declared by the NYISO" • NYISO Actions, #4: at end delete "and shall follow the procedures for severe weather operation." and replace with "and declare an ALERT state." • Transmission Owner Actions, #2: delete "Supervisor" and replace with "personnel" • Add new category at end: "Other Considerations" and beneath it add: "1. For all contingencies which would result in a violation of the Alert State criteria, corrective action, which would be necessary if the contingency occurs shall be determined through coordination between the NYISO Shift Supervisor or their designee and the affected Transmission Owners." • NYISO Actions, #7: move under "Other Considerations" as #2. ➢ Sect. 3.2 • #3b: replace "problem" with "collapse" • Add "3e. If having taken the actions above, the actual voltage at any bus listed in Exhibit A-3 remains below its pre-contingency low limit for 30 minutes or declines to a level below the mid-point between the pre and post contingency low limits and remains there for 15 minutes, then the NYISO Shift Supervisor shall discuss the situation with the Transmission Owner(s) to determine if corrective action could be taken following a

		contingency to prevent a system voltage collapse." • #7, delete +/- and replace with " • #12, replace "overgeneration" with "Overgeneration" ➢ Sect. 3.3.1 • NYISO Actions, #6 l: Replace "Transmission Owner" with "Market Participant" ➢ Sect. 4.4.2 • Under "Declare Warning State" add new #6: "Notify NYISO special ICAP Customers and Emergency Demand Response Program (EDRP) as NYISO Operation Reserves that they may be required to be activated during a specified period of time. (Estimated start and end time announced.)" and renumber the remaining items. • Under "Declare Warning State" add new #10: "Direct Market Participants to activate Emergency Demand Response Program (EDRP) to start at XXXX hrs and end at XXXX hrs." ➢ Sect. 4.4.3 • Under "Declare Alert State", #1, Revise as follows: "If deficient of 10-minute reserve, direct all Market Participants to convert 10 minute non-synchronized 30-minute reserve to energy or 10-minute synchronized 10-minute reserve." • Under "Declare Major Emergency", # 5, Replace "Customers" with "Customer." Add "Activate" before "Emergency". At end add "if possible." ➢ Sect. 4.4.4 • Under "Declare Major Emergency", #4, correct spelling of "activate". Divide sentence into two by ending it at "customer". Insert "Activate" before "Emergency". And, at end of sentence, after (EDRP), add "if possible". ➢ Sect. 4.7 • Under "NYISO Actions", #7, replace "reduce" with "request." ➢ Sect. 6.2 • Under "NYISO Actions", #1, Delete text at end of sentence: "and neighboring control areas where applicable." • Under "NYISO Actions", #6, Change 1st word of each bulleted item from uppercase to lowercase. ➢ Sect. 7.2 • Rearrange and edit information in this section. ➢ Sect. 8.4.2 • Under "Designated NYISO Coordinator Actions", #10, at beginning, delete "Time Correction and", make "Magnetic Disturbance" lowercase, replace "Niagara Mohawk" with "NMPC" and replace "Ontario Hydro" with "OH" • Under "Designated NYISO Coordinator Actions" #11, have "Designated Coordinator" be lowercase. **Changes Inserted May 1, 2001** ➢ Sect. 1.1 • Definition for Emergency Make "Generation Resources" lower case words. ➢ Sect. 1.2.2 • Make the 2nd bulleted list labeled with letters, instead of bullets • Within the 2nd bulleted list, 3rd bullet (now entry c) at the end of the sentence, replace the "Transmission Owner, LSE, and GENCO use" with "Market Participant Load." ➢ Sect. 2.2 • #12, Delete text at end of sentence: "Operating Reserve Deficient." • Add #13: An actual operating reserve deficiency exists."

		➢ Sect. 4.1.1 • b, add “below” before “its LTE rating within 10 minutes from the initial overload.” ➢ Sect. 4.1.2 • Replace “NYS Power System” with “NYISO Secured Transmission System or the NERC Bulk Electric System” ➢ Sect. 4.2 • Replace “NYS Power” with “NYISO Secured Transmission”1st paragraph, last sentence –>delete “short of Load Shedding” at end. ➢ Sect. 4.4.1 • Change title from “Shortage Operating Reserve – Peak Forecast” to “Shortage Operating Reserve – Day Ahead Forecast” • Replace body text to correlate with new title ➢ Sect. 4.4.2 • Change title from “4.4.2 Shortage Operating Reserve – Real Time” to “4.4.2 Shortage Operating Reserve – In Day” Replace body text to correlate with new title ➢ Sect. 4.4.3 • Renumber Section 4.4.3 to 4.4.4 • Update body text Insert a new section 4.4.3 titled: “4.4.3 Shortage Operating Reserve - Real Time” • Insert body text to correlate with title ➢ Sect. 4.7 • NYISO Actions, # 7, replace “request” with reduce” at the beginning. NYISO Actions, # 7, delete “all other” before “inter-Control Area” ➢ Sect. 6.2 • NYISO Actions, #1, at the end add “and neighboring control areas where applicable. NYISO Actions, #3, replace “request” with “order” NYISO Actions, #5, replace “adjacent” with “neighboring” ➢ Sect. 7.1 • 1st paragraph, last sentence, at the end add “the following types of load curtailment”1st set of bulleted items, change bullets to letters ➢ Sect. 7.4.2 • NYISO Actions, #1, after “Transmission,” add “Owner”. NYISO Actions, #1, in middle of sentence, delete: “via the Emergency Hot Line System” ➢ Attachment D • Exhibit D-3, In Table, Heading on 2nd Column, replace “Step” with “Type of Curtailment” Exhibit D-3, Under Table, Under (Time and Date), add: “Type of Curtailment: a. Curtailment of interruptible load, b. Manual (local) voltage reduction, c. Curtailment of nonessential Market Participant load, d. Voluntary curtailment of large LSE customers, e. Public appeals” ➢ Attachment F • 1st page, delete “***Note to NYISO: Exhibits F-1 and F-2 need to be replaced.***” • F1, delete table F1 • F2, delete table F1
2.0	**09/12/2000**	**Changes Inserted September 12, 2000** ➢ Sect. 1.6.1 • #2: Replace “Provider” with “Owner” • Paragraph after #5: Replace “Provider” with “Owner” ➢ Sect. 1.6.2 • First sentence: Replace “Provider” with “Owner”

		➢ Sect. 2.2 • #1: delete “NYS ISO” and replace with “NYISO” • #3: Insert “voltage” before “collapse.” • #7: delete “Pool” and replace with “Area” • The following corrections made to the sentence after #11: An Operating Reserve deficiency is predicted, Operating Reserve Deficient. ➢ Sect. 2.3 • 1st sentence: Insert “State” after “Alert” • 1st sentence: Insert “Shift Supervisor” after the 1st “NYISO” • #3 c & d: Reverse order of info. Should be as follows: 3c. Activate reserves 3d. Adjust reactive sources and transformer taps • #3e: Insert “Perform” before “Generation shifts.” • #3f: Replace “Modify Physical Schedules” with “Modify Interchange Schedules” • #3h: delete “NYS ISO” and replace with: “NYISO” • #3: Insert text after 3i. Label new text 3j. Text to insert: “May call for a reserve pickup to return to schedule if the NYISO Control Error exceeds -100 MW.” • #3: Insert text after new 3j. Label new text 3k. Text to insert: “Take actions to maintain operating reserve, in accordance with the procedures described in Section 4.2 of this manual.” • #3: Re-number the items after the new 3i and 3j. • #3l: Replace “Transmission Owner” with “Market Participant” • #3m: Order Generation to full Operating capability. • #3q: Insert “and generators” after “customers” • #7: Add: 7. If the NYISO Shift Supervisor or their designee foresees an extended period of operation in the Alert State, a canvass of the Transmission Owners shall be made to determine if assistance can be provided through other appropriate means. • Delete: Other Considerations • 1. For all contingencies which would result in a violation of Alert State criteria, corrective action, which would be necessary if the contingency occurs shall be determined through coordination between the NYISO Shift Supervisor or their designee and the affected Transmission Owners. • 2. If the NYISO Shift Supervisor or their designee foresees an extended period of operation in the Alert State, a canvass of the Transmission Owners shall be made to determine if assistance can be provided through other appropriate means. ➢ Sect. 3.2 • #5, #6: Replace “Inter-pool” with “Inter-area” • #7, #12: Replace “Pool” with “Area” ➢ Sect. 3.3.1 • #6: Delete “s” at end of “Baseds” • #6 b: Delete “Shift Supervisor after “NYISO” • #6 c & d: Reverse order of info. Should be as follows: 6c. Activate reserves 6d. Adjust reactive sources and transformer taps • #6 f: Replace “Modify Physical Schedules” with “Modify Interchange Schedules” • #6 g: Delete “Request” and Insert “Order” • #6 h: Insert “to” before “be” • #6 i: change the “r” in “Reduction” to a lower case “r” • #6j: Delete “Request voluntary Market Participant Load Reduction” and Insert “May call for a reserve pick up to return to schedule if the NYISO Control Error exceeds - 100 MW.” • #6k: Delete “Generation may be ordered to full operating capability” and insert “Take actions to maintain operating reserve, in accordance with the procedures described in Section 4.2 of this Manual.”

		• #6l: Delete “Request maximum generation pick-up” and insert “Curtail non-essential Transmission Owner load.” • #6m: Delete “Invoke Emergency Transfer Criteria (ETC).” and insert “Order Generation to full operating capability.” • #6n: Delete “Curtail interruptible load in accordance with contractual arrangements.” and Insert “Order maximum generation pick-up, at emergency response rates.” • #6: Insert a new #6o: Invoke Emergency Transfer Criteria (ETC). And, Insert a new #6p: Curtail interruptible load in accordance with contractual arrangements. • #6: Re-label numbers to accommodate for the insertion of the new 6o and 6p. • New 6q: Delete “Request” and Insert “Order” in its place. • New 6u: Delete “Request” and Insert “Order” in its place. ➢ Sect. 6.1 • Paragraph under two bullets: replace “intra-pool” with “intraarea” ➢ Sect. 6.2 • Transmission Owner Actions: Renumber them as follows: • 1 becomes 3, • 2 becomes 1, • 3 becomes 2. ➢ Attachment A, Exhibit A-1 • Change “Pool Control Error” to “Area Control Error.” Also, change acronym “PCE” to “ACE” • Under the “Alert/Frequency” section, change text from: “Frequency is greater than 60.05 Hz and less than 60.10 Hz OR Frequency is greater than 59.90 Hz and less than 59.95 Hz” to: “Frequency is greater than or equal to 60.05 Hz and is sustained at that level or continues to increase OR Frequency is less than or equal to 59.95 Hz and is sustained at that level or continues to decline.” ➢ Attachment A, Exhibit A-3 • Change the Bowline 345's Pre-Low from 338 to 345 • Change the Buchanan 345's Pre-Low from 338 to 346 • Change the Dunwoodie 345's Pre-Low from 338 to 346 • Delete Hurley Ave 345 and all it’s information completely • Change the Ladentown 345's Pre-Low from 338 to 346 • Change the Oakdale 345's Pre-Low from 335 to 336 • Change the Pannell Road 345's Pre-Low from “see pg.2" to “see A-4" • Change Pleasant Valley 345's Pre-Low from 338 to 343 • Change Ramapo 345's Pre-Low from 338 to 346 • Insert Rock Tavern 345, Pre-Low: 348, Pre-High: 362, Post-Low: 328, Post-High: 362, Set By: CH • Change Roseton 345's Pre-Low from 338 to 345 • Change Sprainbrook 345's Pre-Low from 338 to 345 • Change Station 80 345's Pre-Low from “see pg 2” to “see A4" ➢ Attachment A, Exhibit A-4 • Delete 3rd Column (Oakdale 345 kV) under “Pre contingency Low Bus Voltage Limits” • Under “HQ-NYCA transfer on 7040 is”, 3rd row, change value in first column from “+1351 to +1850" to: “+1351 to +1800" • Delete 4th and 5th rows of information (4th row: +1851 to +2000 MW, 345 kV, 345 kV”, 5th row: “+2001 to +2350MW, 346 kV, 346 kV”) • Delete row at end: “Fraser SVC out of service or ‘not normal’, 339 kV” ➢ Attachment A, Exhibit A-5 • Under the Pleasant Valley-Wood St. Millwood W. Change W78 to W81 **Global Change**

		➢ Replace “Transmission Provider” with “Transmission Owner” throughout the entire manual.
1.0	**09/01/1999**	**Initial Release** September 1, 1999 Section 4.5-Stability Limit Violation

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1. OVERVIEW

This section describes the New York Independent System Operator (NYISO) operating policy, operating states, and the emergency communication system.

1.1 Operating Policy

Under the terms of the NYISO Agreement, the NYISO/Transmission Owners (TO) Agreement, and the NYISO/New York State Reliability Council Agreement, the NYISO has the authority and the responsibility to direct the operation of the New York State (NYS) Power System so as to maintain system reliability in accordance with Good Utility Practice and the Reliability Rules which are applied on a system-wide and local basis.

Power system disturbances are most likely to occur as the result of the loss of generating equipment, transmission facilities, or unexpected load changes. These disturbances may be of, or develop into, a magnitude sufficient to affect the reliable operation of the New York Control Area (NYCA). Severe system disturbances generally result in critically loaded transmission facilities, critical frequency deviations, high or low voltage conditions, or stability problems.

NYISO Authority to Respond to Transmission Exceedances on New York State Transmission System (NYS Transmission System)

North American Electric Reliability Commission (NERC) Reliability Standards provide NERC Registered Entities with the authority to take actions to mitigate System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) Attachment A Table A.6 exceedances. Transmission Owners (TO) shall disconnect the affected facility if the overload on a transmission facility or if an abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Owner shall notify the NYISO and all neighboring Transmission Owners impacted by the disconnection prior to switching, if time permits, otherwise immediately after switching. The NYISO shall maintain the safety and short-term reliability of the NYS Transmission System in accordance with the Reliability Rules and in accordance with the NYISO/NYSRC Agreement and the NYISO/TO Agreement.

This Manual addresses the NYISO and Market Participants' actions under emergency conditions. An ***Emergency*** in the NYCA is defined as:

> Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of the NYS Power System.

It is the intention of the NYISO to implement the procedures and criteria provided in this Manual when necessary to maintain a reliable system. In cases where the NYISO makes a judgment that the market cannot provide needed services within criteria, those actions shall be supplemented by those that can provide the fastest possible relief.

The NYISO will restore the NYS Power System to normal operation as soon as possible following any situations where emergency actions have been invoked.

The following definition for "Order" will be used.

> After declaration of a Major Emergency, any request made by the NYISO to a Transmission Owner for remedial action including but not limited to, Load Shedding, shall be considered an Order to effect such remedial action.

In relation to the procedures addressed by this Manual, non-specific references to NYISO personnel in the form of *the NYISO* should be inferred as meaning the NYISO Power System Operators in the NYISO control room.

1.2 Operating States

The following five operating states are defined for the NYS Power System:

1. Normal
2. Warning
3. Alert
4. Major Emergency
5. Restoration

1.2.1 Determining the Operating State

The NYISO shall determine the state of the NYS Power System by comparing system conditions against certain monitoring criteria. The NYISO also shall monitor weather conditions and forecasts.

- When the NYISO determines that the state of the NYS Power System is Normal or Warning, the NYISO shall operate the NYS Power System according to procedures described in the *NYISO Transmission and Dispatching Operations Manual*.
- When the NYISO determines that the state of the NYS Power System is Alert, Major Emergency, or Restoration, the NYISO shall operate the NYS Power System according to procedures in this Manual.

1.2.2 Operating Objectives

The objective of the NYISO is to operate the NYS Power System within the Normal State. Conditions, however, may cause the NYS Power System to depart from the Normal State. These conditions include, but are not limited to, the following:

- Capacity deficiencies
- Reserve deficiencies
- Energy deficiencies
- Loss of generation or transmission facilities
- High voltage
- Low voltage
- Fuel emergencies
- Environmental episodes

- Stability problems

When the NYS Power System enters a condition other than the Normal State, the NYISO shall act to return the NYS Power System to the Normal State. When all the criteria for the Normal State cannot be achieved, the NYISO shall satisfy as many of the Normal State criteria as possible and shall minimize the consequences of any single contingency. Should a disturbance occur, its extent and duration shall be minimized.

When multiple exceedances occur in the same state, actual exceedances shall be corrected before predicted exceedances. Where multiple exceedances of differing state criteria occur, the most serious exceedance shall be solved first.

The NYISO Schedule Coordinator, the NYISO, or both shall forecast the likelihood of the occurrence of states other than the Normal State as far in advance as possible. If it is predicted that Load Relief, either by Voltage Reduction or Load Shedding, may be necessary during a future period, the NYISO shall notify all TOs and preparatory arrangements shall be made for corrective measures requiring substantial lead time, including:

a. Curtailment of interruptible load [Special Case Resources (SCR) & Emergency Demand Response Programs (EDRP)]
b. Manual (local) Voltage Reduction
c. Curtailment of non-essential Market Participant Load
d. Voluntary curtailment of large Load Service Entities (LSE) customers
e. Public appeals

Transmission Owners shall develop the necessary communication policies with their Transmission Customers. The specific operating methods used by each TO are not necessarily identical. The NYISO shall coordinate such methods in order to achieve uniform results.

In the event that a TO loses communications with the NYISO the TO shall operate its system in accordance with the procedures defined in this Manual.

1.2.3 Generator Response During Reserve Activation

Units with or without a Reserve Award

All units are expected to respond to a reserve pickup 10-minute basepoint at its emergency response rate as bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its RTD basepoint, which will be consistent with the Locational Based Marginal Pricing (LBMP), within three RTD intervals (15 min) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.

1.3 Governmental and Public Relations Notification Procedures

The NYISO is required to notify federal and state government agencies, interconnected systems, and the designated NYISO External Affairs contact when unusual operating conditions occur on the NYS Power System.

1.3.1 NYISO – Transmission Owner Emergency Notifications

When disturbance events occur on the system, the NYISO and the Transmission Owners must share information to ascertain the state of the system and to provide clear notification to the appropriate groups to meet NYISO and TO reporting criteria.

The NYISO is responsible for the continuous monitoring and assessment of conditions on the NYS Power System. In order to facilitate the NYISO's duty to communicate, TOs shall notify the NYISO of significant disturbance events on their systems.

The NYISO and TOs are required to file reports to the Department of Energy (DOE) for events that are identified and listed in DOE Form OE-417. In the case of NYS Power System events, the NYISO will collect information readily available at the Power Control Center (PCC) and may request supporting information from the appropriate TOs, if needed. Events that are directed by the NYISO, such as Load Shedding and Voltage Reduction, need not be reported by the TOs. The NYISO will report on behalf of the NYCA as described in section 1.3.3, "NYISO DOE Notification."

Events occurring on facilities ***not*** considered part of the NYS Power System may still require DOE OE-417 reporting by the appropriate TOs. The NYISO needs to be made aware of these events and may also need to report on them. To ensure information flow and consistency, TOs will send copies of their OE-417 reports to the NYISO when issuing these reports to the DOE.

Methods of Reporting

TO System Operators will verbally notify the NYISO of local conditions and system status. If unilateral corrective action by the Transmission Owner(s) is required as a result of a violation severe enough to require immediate action, the TO System Operators must keep the NYISO informed as soon as the initial event has been secured.

TO System Operators will e-mail copies of their DOE Form OE – 417 reports to reliability_compliance@nyiso.com with the subject line: *OE – 417*. In the event that e-mail is not functioning, the form will be faxed to 518-356-6237. These reports shall be made concurrent with DOE reporting.

1.3.2 NYS Public Service Commission (PSC) Notification

The NYISO shall notify the PSC within one hour, 24 hours per day, when any of the following unusual operating conditions occurs:

- Impending power supply shortfall
- Curtailed electric use

- Voltage Reduction
- Load Shedding
- Unusual events as defined by the PSC
- Major outages in neighboring systems

Information reported to the PSC shall be telephoned to the first individual on the PSC Notification List who is available. The NYISO also shall immediately notify the NYISO Operations Management. .

NYISO Management shall notify the PSC on the next business day when other NYS Power System emergencies occur. NYISO Management also shall respond to requests for additional information on conditions reported by the NYISO. During non-business hours, the NYISO shall report all appropriate incidents to the first available individual on the PSC Notification List.

When a Major Emergency is declared, the NYISO shall complete the part of the form in Attachment G of this Manual that applies to the incident. The NYISO shall supply this information directly to the PSC, if required, or NYISO Management responsible for telephoning the PSC otherwise.

The NYISO shall record the data supplied to the PSC, the date and time it was supplied, and to whom it was given. The NYISO shall make that information available to NYISO Operations Management.

1.3.3 NYISO DOE Notification

The NYISO, as appropriate, must submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center that operates on a 24 hour basis, 7 days a week.

Form OE – 417 must be submitted to the DOE Operations Center via fax within 1 hour if one of the following applies:

1. Uncontrolled loss of 300 MW or more of firm system loads for more than 15 minutes from a single incident
2. Load Shedding of 100 MW or more implemented under emergency operational policy
3. System-wide voltage reductions of 3 percent or more
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism which target components of any security systems
6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability
7. Fuel supply emergencies that could impact electric power system adequacy or reliability

8. Loss of electric service to more than 50,000 customers for 1 hour or more. (This event will be reported by the Transmission Owner; see section 1.3.1.)
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system

1.3.4 NYISO Public Relations' Notification

The NYISO shall notify the designated NYISO External Affairs contact or the designated alternate when system conditions exist that may result in general public awareness of an actual or impending situation. .

1.4 Communications

This section describes communication procedures among the NYISO, the TOs, and neighboring Reliability Coordinators during Alert, Major Emergency, and Restoration States.

1.4.1 Emergency Notification

When an Alert State or Major Emergency State occurs, the NYISO shall communicate with the affected TO(s) to determine the nature of the problem and to make a preliminary estimate of the assistance required.

The NYISO shall notify all TOs via the Emergency Hot Line System that an Alert State or Major Emergency State exists.

When the Restoration State occurs, the NYISO shall notify all TOs via the Emergency Hot Line System that a Restoration State exists.

1.4.2 Non-Emergency Communications

Transmission Owners from non-affected areas who wish to talk with NYISO for communications not related to the Major Emergency shall have their calls responded to as system conditions dictate.

Transmission Owners requesting information on routine business may contact the NYISO; non-emergency communications shall be kept as brief as possible.

TOs shall notify the NYISO immediately of transmission line status changes in non-affected areas.

1.4.3 Emergency Status Updates

As soon as possible after the extent of the system disturbance is determined, the NYISO shall notify all TOs and neighboring Reliability Coordinators of the operating state of the NYS Power System. Neighboring Reliability Coordinators shall be notified via telephone and if appropriate the NERC Reliability Coordinator Information System (RCIS) shall be updated.

The NYISO shall issue reports to the TOs and the neighboring Reliability Coordinators as significant changes occur.

1.4.4 Dissemination of Emergency Communications

When a communication regarding an emergency situation or another significant event not covered in other sections of this Manual is received at the NYISO, the NYISO shall communicate the message to all TOs.

When such a communication is received at a TO Energy Control Center, the TO shall notify the NYISO of the content of the communication. The NYISO shall then notify all TOs.

1.5 Emergency Communication Systems

The NYISO uses several emergency communication systems to coordinate emergency actions and disseminate information during emergency conditions. The following systems are described in this section:

- Emergency Hot Line System
- Load Shed Alarm System
- Alternate Control Center Emergency Hot Line
- NERC Reliability Coordinator Information System

1.5.1 Emergency Hot Line System

The Emergency Hot Line System is a network of dual-routed, multi-point, private-line telephone circuits having voice and alarm capability that connects the Control Centers of all TOs with the Primary Control Center (PCC). The Emergency Hot Line System provides for notification of Emergency conditions by the NYISO simultaneously to all TOs.

The primary purpose of the Emergency Hot Line System is to notify all TOs that an abnormal condition exists on the NYS Power System. Corrective measures for the situation are directed by the NYISO. The NYISO shall use the Emergency Hot Line System for the following purposes:

- Notifying all TOs that Emergency Transfer Criteria are in effect or terminated.
- To activate reserve.
- Declaring or terminating an Alert State, a Major Emergency State, or a Restoration State.
- For Voltage Reduction, Load Shedding, or both.
- For corrective actions required as a result of a contingency.
- Other communications at the discretion of the NYISO.

The Emergency Hot Line System consists of two circuits, designated "A" and "B" from the PCC to each TO Energy Control Center, and telephone sets at the TO Energy Control Centers. When a call is initiated by the PCC, one circuit from each location is connected to the conference bridge.

Equipment at the PCC provides a visual indication to the NYISO as to which TO telephones are on line (off-hook). Visual and audible alarms also indicate any Emergency Hot Line System malfunctions.

Only the NYISO can initiate a conference call connecting all TOs.

1. Upon receiving an Emergency Hot Line signal from the NYISO, each TO shall join the conference without announcing their identity. NYISO Emergency Hot Line communication protocol is to provide information to the TOs. When a directive is issued, the TO will be required to repeat back the directive.
2. If more than ten seconds elapse and all TOs are not on the line, the NYISO shall note which TO(s) is/are not on line and then shall issue necessary instructions. Upon completion of the message, the NYISO shall instruct the non-responding TO by other means.
3. Transmission Owners shall remain on the line until the NYISO indicates the message is complete.
4. Transmission Owners can transfer to the stand-by telephone circuit if loss of communications occurs during a conference call.
5. A TO may request assistance in meeting a contingency by using the Emergency Hot Line System to contact the NYISO. The NYISO may then conference the remaining TOs on the Emergency Hot Line System if conditions warrant.

Testing of the Emergency Hot Line System shall be initiated by the NYISO on a daily basis, unless it is used in the course of daily operations. The NYISO receives an indication of any Emergency Hot Line System malfunction and has continuous indication of which TO telephones are off-hook.

The NYISO shall advise all TOs if the Emergency Hot Line System is out of service or is expected to be out of service, and shall advise all TOs regarding its restoration to normal operation.

The NYISO shall report any trouble on the Emergency Hot Line System to the service provider. TOs shall report any problems to the NYISO.

1.5.2 Load Shed Alarm System

The Load Shed Alarm System operates a flashing strobe light in each TO Energy Control Center.

When the NYISO orders a TO to shed load, the NYISO shall immediately activate the Load Shed Alarm System, which causes the Load Shed Alarm light in the TO’s Energy Control Center to begin flashing.

For additional detailed information about the use and testing of the Load Shed Alarm System, see the Load Relief, section 7 of this Manual.

1.5.3 Alternate Control Center Emergency Hot Line

The NYISO Alternate Control Center (ACC) shall be used when the PCC must be evacuated or for drills in accordance with the procedures in the Testing Emergency Procedures, section 9 of this Manual.

The ACC Emergency Hot Line consists of a set of designated telephones with preset conferencing capability for all TOs. When the ACC is established, or when conferencing is required, the NYISO shall notify all TOs via the ACC Emergency Hot Line. Transmission Owners must acknowledge this call on their designated telephones when answering, since the NYISO does not have off-hook indication at the ACC. Transmission Owners shall acknowledge calls with the name of the TO and the Transmission Owner Operator's name.

The NYISO shall test the conferencing capability of the ACC Emergency Hot Line on a weekly basis. The NYISO shall log the results. The NYISO shall report any trouble on the ACC Emergency Hot Line to the service provider. TOs shall be responsible for their designated telephones.

The designated telephones of TOs are programmed for conferencing by the NYISO from the ACC. Any change in telephone numbers requires reprogramming. The TO shall notify the NYISO of any change in telephone numbers. The NYISO shall have the change implemented.

1.5.4 NERC Reliability Coordinator Information System

The system the Reliability Coordinators use to post messages and share operating information in real time is called (RCIS) Reliability Coordinator Information System.

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2. ALERT STATE

This section describes the Alert State.

2.1 Definition of the Alert State

The Alert State exists when conditions on the NYS Power System are more severe than in the Warning State. Immediate actions are required to return the NYS Power System to the Normal State.

2.2 Alert State Criteria

The Alert State exists when the following occur:

If a transmission facility, defined as the NYISO Secured Transmission System or the NERC Bulk Electric System, becomes overloaded, relief measures shall be applied immediately to bring the loading within established ratings.

1. Pre Contingency (Actual) Flow Criteria
   - Normal Transfer criteria: When a facility becomes loaded above its LTE rating, but below its STE rating for less than five (5) minutes corrective action must be taken to return the loading on the facility to its LTE rating or lower within fifteen (15) minutes.
   - *Emergency Transfer Criteria are invoked*: Actual loading of equipment defined as the NYISO Secured Transmission System or the NERC Bulk Electric System is greater than Normal rating but less than or equal to Long-Term Emergency (LTE) rating for greater than 30 minutes and may exist up to four continuous hours (or such longer period as may be established by the Rating Authority).
2. Post Contingency Flow Criteria

   Single Circuit Criteria:
   - *Emergency Transfer Criteria are invoked*: Predicted flow of equipment defined as the NYISO Secured Transmission System or the NERC Bulk Electric System is greater than Short-Term Emergency (STE) rating and corrective action could be taken to reduce the flows under STE in 5 minutes and under LTE within 10 minutes following the contingency ***AND*** predicted flow has not exceeded its STE rating for greater than 30 minutes.

   Two adjacent circuits on the same structure Criteria or stuck circuit breaker contingencies:
   - *Emergency Transfer Criteria are invoked:* Post Contingency flow may exceed STE rating.
3. The actual voltage on any bus listed in Table A-2 is below its pre-contingency low limit and is indicative of a system Voltage Collapse or above its pre-contingency high limit for less than 15 minutes or is above its post-contingency high limit for less than 10 minutes..

4. Post-contingency flows exceed IROL limits associated with Voltage Collapse for less than 15 minutes and less than 5%.
5. Sufficient 10-Minute Reserves exist to meet the requirements as specified in the *NYISO Transmission and Dispatching Operations Manual* (available from http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20), but only if Quick Response Voltage Reduction is counted, and/or there are sufficient sales off the NYISO reference bus, and the appropriate Reliability Coordinator has been notified that those sales are being counted or curtailed by the NYISO based on the Reliability Coordinator's ability to have the transaction curtailed.
6. A NYISO IROL stability limit is exceeded for less than 15 minutes and less than 5%.
7. The ACE is greater than +/-500 MW for less than 10 minutes.
8. The System Frequency is between 59.90 and 59.95 or between 60.05 and 60.10.
9. Partial communications, computer control or indication facilities necessary to monitor these criteria are not available and, in the judgment of the NYISO, the system is in jeopardy.
10. A neighboring Reliability Coordinator is in Voltage Reduction or Load Shedding, but has not requested that the NYISO go into Voltage Reduction.
11. A situation involving impending severe weather or severe Solar Magnetic Disturbances exists.
12. An Operating Reserve deficiency is predicted.

2.3 Responses to the Alert State

When an Alert State is declared by the NYISO, the NYISO and the TOs shall perform the actions described in this section.

NYISO Actions

The NYISO shall monitor system conditions at all times and determine the action(s) listed below that are necessary to return the NYS Power System to the Warning State and, if possible, to the Normal State.

1. Coordinate actions with TOs and Reliability Coordinators.
2. Communicate as soon as possible with all TOs, via the Emergency Hot Line System, that an Alert State has been declared, stating the reasons for the change of state.
3. Initiate one or more of the following remedial actions based upon severity and time constraints.
   a. Adjust phase angle regulators.
   b. Shift or start generation in order to obtain additional reactive power (MVAr) control.
   c. Activate reserves.
   d. Adjust reactive sources and transformer taps.

e. Perform Generation shifts.
f. Modify Interchange Schedules.
g. Request NYS Transmission System facilities that are out of service for maintenance be returned to service.
h. For high voltage conditions only, request NYS Transmission System facilities that are in service be removed from service where appropriate.
i. Implement Manual Voltage Reduction.
j. May call for a reserve pick-up to return to schedule if the Area Control Error (ACE) exceeds - 100 MW.
k. Take actions to maintain operating reserve, in accordance with the procedures described in section 4.4 of this Manual.
l. Direct Demand Side Resources and the TOs to
   - Curtail non-essential Market Participant load.
   - Curtail interruptible load in accordance with contractual arrangements.
   - Request large industrial and commercial customers to curtail load voluntarily.
m. Move Generation to Upper Operating Limit Emergency (UOLe).
n. Request maximum generation pick-up, at emergency response rates.
o. Invoke Emergency Transfer Criteria (ETC).
p. Purchase Emergency Energy from neighboring Reliability Coordinators.
q. Issue general radio and television appeals to the public to restrict unnecessary use.
r. Communicate with neighboring Reliability Coordinators that are creating the condition and request relief.
s. Request assistance from neighboring Reliability Coordinators.
t. Activate SCR and EDRP Resources.

4. When a situation exists in which the effects of impending severe weather may severely jeopardize the security of the NYS Power System, the NYISO shall notify all TOs of the impending conditions and declare an Alert State.
5. For all contingencies that would result in an exceedance of Alert State criteria, the NYISO shall determine the corrective actions that would be necessary if the contingency occurs, through coordination with the affected TOs.
6. If the NYISO foresees an extended period of operation in the Alert State, the NYISO shall solicit bids from all Market Participants.
7. Communicate as soon as possible with all TOs via the Emergency Hot Line when the Alert State has been terminated.

Transmission Owner Actions

The TOs shall perform the following:

1. Coordinate and implement corrective actions as required by the NYISO .
2. Monitor local weather conditions and shall inform NYISO if local severe weather conditions occur or if they are predicted to occur by regional forecasts.

3. Monitor conditions with respect to their own systems.
4. Whenever a TO observes a system condition that exceeds the current NYISO system state, the TO shall take the following actions:
   a. Notify the NYISO that a local emergency exists.
   b. Request assistance of the NYISO, as required.
   c. Disconnect the affected facility if there is an overload on a transmission facility or if an abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Owner shall notify the NYISO who will inform all neighboring Transmission Owners and Reliability Coordinators impacted by the disconnection prior to switching if time permits, otherwise immediately after switching.

Other Considerations:

1. For all contingencies that would result in a violation of the Alert State criteria, corrective action, which would be necessary if the contingency occurs, shall be determined through coordination between the NYISO and the affected TOs.
2. If the NYISO foresees an extended period of operation in the Alert State, a canvass of the TOs shall be made to determine if assistance can be provided through other appropriate means.

3. MAJOR EMERGENCY STATE

This section describes the Major Emergency State.

3.1 Definition of the Major Emergency State

The Major Emergency State exists when conditions on the NYS Power System are more severe than in the Alert State. Immediate actions are required to avoid damage to power system equipment or loss of load and to return the NYS Power System to the Normal State.

3.2 Major Emergency Criteria

The Major Emergency State exists when the following occur:

1. Pre Contingency (Actual) Flow Criteria

   Normal Transfer Criteria

   - A transmission facility, which constitutes part of the NYISO Secured Transmission System or the NERC Bulk Electric System, becomes loaded above its Short-Term Emergency (STE) rating.
   - *Normal Transfer Criteria:* A transmission facility, which constitutes part of the NYISO Secured Transmission System or the NERC Bulk Electric System, becomes loaded above its Long-Term Emergency (LTE) rating for greater than five (5) minutes or at the discretion of the NYISO, immediately if system conditions warrant an immediate declaration of the Major Emergency State.
   - *Emergency Transfer Criteria are invoked:* A transmission facility, which constitutes a part of the NYISO Secured Transmission System or the NERC Bulk Electric System remains loaded above its Normal rating, but equal to or less than its LTE rating for more than four continuous hours or such longer period as may be established by the Rating Authority.
2. Post Contingency Flow Criteria

   Single Circuit Criteria:

   - *Emergency Transfer Criteria are invoked:* A transmission facility which constitutes a part of the NYISO Secured Transmission System or the NERC Bulk Electric System remains at a loading level for greater than 30 minutes, which would cause its Short-Term Emergency (STE) rating to be exceeded following a contingency, ***or***
   - *Emergency Transfer Criteria are invoked:* A transmission facility which constitutes a part of the NYISO Secured Transmission System or the NERC Bulk Electric System becomes loaded to a level that would cause its STE rating to be violated and corrective action could not be taken rapidly enough to meet the requirements, under STE in 5 minutes and under LTE within 10 minutes of initial overload, once the contingency occurs.
3. The actual voltage on any bus listed in Attachment A, Table A.2 is:

a. Below its pre-contingency low limit or above its pre-contingency high limit for 15 minutes, and is indicative of a System Voltage Collapse.
b. Below its pre-contingency low limit and is indicative of a System Voltage Collapse, and appropriate voltage control measures have already been utilized.
c. Below its post-contingency low limit and is indicative of a system problem.
d. Above its post-contingency high limit for 10 minutes.
e. If having taken the actions above, the actual voltage at any bus listed in Attachment A, Table A.2 remains below its pre-contingency low limit for 30 minutes or declines to a level below the mid-point between the pre and post contingency low limits and remains there for 15 minutes, then the NYISO shall discuss the situation with the TOs to determine if corrective action could be taken following a contingency to prevent a System Voltage Collapse.

4. A deficiency in 10-Minute Reserve or Operating Reserve exists. If Sufficient 10-Minute Reserve does not exist to meet the requirements as specified in the *NYISO Transmission and Dispatching Operations Manual* (available from http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20), even after Quick Response Voltage Reduction is counted, and/or there are insufficient sales off the NYISO reference bus, and the appropriate Reliability Coordinator has been notified that those sales are being counted or curtailed by the NYISO based on the Reliability Coordinator's ability to have the transaction curtailed.
5. The post-contingency flow on an internal NYCA IROL interface or towards NYCA on an inter-area IROL interface exceeds limits associated with a Voltage Collapse by 5% or more or those limits are exceeded by less that 5% and corrective measures are not effective within 15 minutes.
6. The power flow on an internal NYCA IROL interface or towards NYCA on an inter-area IROL interface exceeds its stability limit by 5% or more or its stability limit is exceeded by less than 5% and corrective measures are not effective within 15 minutes.
7. The Area Control Error (ACE) is greater than +/-500 MW and normal corrective procedures are not effective within 10 minutes.
8. System Frequency declines to 59.9 Hz. or increases to 60.1 Hz, and is sustained at that level or continues to decline below 59.9 Hz. or increase above 60.1 Hz.
9. Communications, computer, control, and indications facilities necessary to monitor these criteria are not available and, in the judgment of the NYISO, the system is in serious jeopardy.
10. A neighboring Reliability Coordinator already in Voltage Reduction has requested assistance that can only be achieved through Voltage Reduction within the NYCA.
11. Portions of the NYISO system are separated.
12. The NYCA is overgenerating, and steps outlined in the section 4.7, "Overgeneration," of this Manual have been taken, and are not sufficient to reduce the ACE to zero.

3.3 Responses to Major Emergency

The NYISO has the authority and the responsibility to declare that a Major Emergency State exists whenever any of the defined conditions are met.

TOs have the responsibility to determine that an Emergency exists on their own system and to notify the NYISO of the conditions.

3.3.1 Major Emergency Declared by NYISO

When a Major Emergency is declared by the NYISO, the NYISO and the TOs shall perform the actions described in this section.

NYISO Actions

The NYISO shall monitor system conditions at all times and determine the action(s) listed below that are necessary to alleviate the Emergency and Order that such measures be implemented.

1. Coordinate actions with TOs and other Reliability Coordinators.
2. Communicate as soon as possible with all TOs, via the Emergency Hot Line System, that a Major Emergency has been declared, stating the reasons for the change of state.
3. Suspend all prescheduled generation changes until the NYISO determines that they will not aggravate system conditions.
4. Verify the status of the NYS Power System with all TOs whose facilities are involved in the Major Emergency.
5. Determine which remedial actions must be taken by any of the TOs to alleviate the Major Emergency.
6. Order one or more of the following remedial actions in the appropriate sequences based upon severity and time constraints:
    a. Adjust phase angle regulators.
    b. Shift or start generation in order to obtain additional reactive power (MVAr) control.
    c. Activate reserves.
    d. Adjust reactive sources and transformer taps.
    e. Perform Generation shifts.
    f. Modify Interchange Schedules.
    g. Order NYS Transmission System facilities that are out of service for maintenance to be returned to service.
    h. For high voltage conditions only, order NYS Transmission System facilities that are in service to be removed from service where appropriate.
    i. Order the affected facility or facilities disconnected if there is an overload on a transmission facility or if an abnormal voltage or reactive condition persists and equipment is endangered.
    j. Implement Manual Voltage Reduction.

k. May call for a reserve pick up to return to schedule if the Area Control Error exceeds -100 MW.
l. Take actions to maintain operating reserve, in accordance with the procedures described in section 4.4 of this Manual.
m. Direct Demand Side Resources and the TOs to:
   - Curtail non-essential Market Participant load.
   - Curtail interruptible load in accordance with contractual arrangements.
   - Order large industrial and commercial customers to curtail load voluntarily.
n. Order Generation to Upper Operating Limit Emergency (UOLe).
o. Order maximum generation pick-up, at emergency response rates.
p. Invoke Emergency Transfer Criteria (ETC).
q. Purchase Emergency Energy from neighboring Reliability Coordinators.
r. Issue general radio and television appeals to the public to restrict unnecessary use.
s. Communicate with neighboring Reliability Coordinators that are creating the condition and request relief.
t. Request assistance from neighboring Reliability Coordinators.
u. Activate SCR and EDRP Resources.
v. Order Quick Response Voltage Reduction in those areas where it will relieve the condition that placed the NYISO in the Major Emergency. This step shall be taken immediately if the need for Load Shedding appears likely.
w. Determine the amount and location of Load Shedding required to relieve condition that placed the NYISO in the Major Emergency and order the Load Shedding. Such orders shall be followed immediately by a visual signal to the TO(s) involved via the Load Shed Alarm System.

7. Arrange to notify all TOs and neighboring Reliability Coordinators, and keep them informed, on a timely basis, of the current status of the NYS Power System.
8. Coordinate the restoration of the NYS Power System and the termination of Load Relief measures, as conditions permit.
9. Communicate as soon as possible with all TOs, via the Emergency Hot Line System, when the Major Emergency is terminated.

Transmission Owner Actions

The TOs shall perform the following:

1. Execute Orders received from the NYISO in accordance with this section.
2. Notify the NYISO immediately upon completion of Orders received from the NYISO.
3. Inform the NYISO of changes in system status.
4. Coordinate corrective action with the NYISO.
5. Disconnect the affected facility if there is an overload on a transmission facility or if an abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the TO shall notify the NYISO, who will inform all neighboring TOs

and Reliability Coordinators impacted by the disconnection prior to the switching if time permits, otherwise immediately after switching.

6. If time and flow conditions permit, notify the NYISO of the intended action and the NYISO shall notify all other TOs and Reliability Coordinators involved prior to opening the transmission facilities.

3.3.2 Emergency Declared by Transmission Owner

When TOs declare that an Emergency exists on their system, the NYISO and the TOs shall perform the actions described in this section.

Transmission Owner Actions

The TOs shall perform the following:

1. Monitor conditions with respect to their own systems at all times.
2. Whenever conditions exist that are within the criteria defined as a Major Emergency, immediately notify the NYISO that a Major Emergency condition exists.
3. Direct the operation of the generation, which is connected to its transmission system and transmission facilities to effect prompt remedial action during Emergencies on their own systems.
4. Direct immediate corrective action to prevent cascading events that may cause equipment damage.
5. Keep the NYISO fully informed of local conditions and system status.
6. Request assistance from the NYISO, if needed.

NYISO Actions

The NYISO shall perform the following:

1. Evaluate the problems on the TO system that requires assistance and shall determine whether a Major Emergency should be declared.
2. If the NYISO declares a Major Emergency, the NYISO shall initiate appropriate actions as described in this section.
3. If the NYISO does not declare a Major Emergency, the NYISO shall perform the following actions:
   a. Notify all TOs, via the Emergency Hot Line System, that a Major Emergency does not exist, but that they should be prepared to provide assistance if it becomes necessary.
   b. Coordinate any assistance requested by the TO that has declared that an Emergency exists.

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4. MONITORED CONDITIONS

This section describes all monitored conditions.

4.1 Transmission Rating Exceedance

A Major Emergency may exist due to a transmission rating exceedance for one of the following reasons:

- Actual Long-Term Emergency (LTE) rating exceedance for greater than five (5) minutes
- Actual Long Term Emergency (LTE) rating exceedance with no time delay at the NYISO's discretion
- Actual Short-Term Emergency (STE) Rating Exceedances
- Post-Contingency STE Rating Exceedance

4.1.1 Actual LTE and STE Rating Exceedance

If a transmission facility that constitutes a part of the NYISO Secured Transmission System or the NERC Bulk Electric System (as defined in the *NYISO Transmission and Dispatching Operations Manual*, available from http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20) becomes overloaded, the NYISO shall apply relief measures immediately to bring the flow within established ratings.

a. When a facility becomes loaded above its LTE rating but below its STE rating, corrective action, which may include Voltage Reduction and/or Load Shedding, must be taken to return loading on the facility to its LTE rating within 15 minutes.
b. When a facility becomes loaded at or above its STE rating, immediate corrective action, which may include Voltage Reduction and/or Load Shedding must be initiated to reduce the loading on the facility to below its STE rating within 5 minutes and furthermore, to continue to reduce the loading on the facility to below its LTE rating within 10 minutes from the initial overload.

If the loading is substantially above the STE rating, Load Relief should be considered as the initial action to be taken.

c. After the loading on a facility has been reduced below its LTE rating, additional corrective action, excluding further Voltage Reduction and/or Load Shedding should be taken to reduce the loading on the facility below its Normal rating within 30 minutes of the initial overload.

In the event this cannot be accomplished, the NYISO shall invoke Emergency Transfer Criteria (ETC).

Emergency Transfer Criteria (ETC)

When there is insufficient capacity or voltage support to maintain facilities within Normal Transfer Capabilities, facilities may, within the guidelines set forth in this document, be allowed to operate to their Emergency Transfer Capabilities. Facilities operating outside their Normal Transfer Capabilities are operating under "Emergency Transfer Criteria."

d. When a facility has been loaded for four continuous hours (or such longer period as may be established by the Rating Authority) above its Normal rating, but at or below its LTE rating, corrective action, which may include Voltage Reduction and/or Load Shedding, must be taken to return the facility to its Normal rating within 30 minutes.

4.1.2 Post-Contingency STE Rating Exceedances

If a transmission facility which constitutes a part of the NYISO Secured Transmission System or NERC Bulk Electric System is being operated under ETC and becomes loaded to a level which would cause its Post-Contingency loading to exceed its STE rating, and corrective action could not be taken rapidly enough to meet the requirements of this policy once the contingency occurs (under STE in 5 minutes and under LTE within 10 minutes of initial overload), then immediate corrective action, which may include Voltage Reduction and Load Shedding must be taken to reduce the loading such that sufficient time will be available to apply corrective action following the contingency, this will be classified as an IROL exceedance. To prevent an IROL Violation, pre-contingency action is required to be taken so that the IROL exceedance is not greater than 30 minutes.

4.1.3 Procedure for Relief of Potential Overloads on Non-Secured Facilities

The NYISO Security Analysis Program identifies and alerts the NYISO to actual and potential overloads on the NYS Transmission System. Occasionally actual or post-contingency potential overloads on non–secured facilities occur which, if uncorrected, could lead to cascading outages and subsequent overloads on NYS Transmission System facilities.

This procedure defines actions to be taken by the NYISO when such conditions exist in order to coordinate an appropriate action plan.

Procedure

1. During normal operation, the NYISO shall monitor the state of the system utilizing the NYISO Security Analysis Program. Whenever the actual or predicted post-contingency power flow on a monitored non-secured facility exceeds its applicable limit, the NYISO shall notify the TO.
2. If the predicted post-contingency loading is greater than LTE, but less than or equal to the STE rating of the facility, an action plan should be formulated, or refer to previously agreed upon operating practice for implementation by the TO.
3. If the predicted post-contingency flow exceeds the STE rating of the facility, the NYISO shall determine if the loss of the facility would cause other facilities to

exceed their STE post-contingency ratings. If the affected facility's loss would cause other non-secured facilities to exceed their STE rating or any NYISO Secured Transmission System or NERC Bulk Electric System to exceed their LTE rating (except where post-contingency flows up to STE ratings are permitted by exceptions noted in Attachment A, to this Manual) the NYISO shall inform the TO and they shall jointly develop a strategy for correcting the condition. The TO shall carry out these corrective actions to relieve the condition within 30 minutes, excluding Voltage Reduction and Load Shedding.

4. If the TO cannot relieve the problem using its own resources, the TO shall obtain assistance from the NYISO.
5. If the condition cannot be corrected within 30 minutes of the initial violation the NYISO shall, through coordination with the TO, neighboring TOs, and neighboring Reliability Coordinators, determine and request the actions necessary to provide relief. Such actions shall include:
   a. Modifications of energy transactions.
   b. Phase angle regulator adjustments.
   c. Generation Shift.
   d. Reserve activation.
   e. Generation may be requested to UOLe, and transmission facilities out of service for maintenance, be returned to service.
6. If these measures are insufficient to comply with Normal Transfer Criteria on NYISO Secured Transmission System or the NERC Bulk Electric System facilities or ETC for non-secured facilities within 30 minutes of the initial violation or Operating Reserve cannot be delivered due to transmission limitations for 30 minutes, the NYISO shall take the following actions:
   a. Notify all TOs via the Emergency Hot Line System that ETC are in effect, for the facility(ies) involved.
   b. Take action as required to stay within ETC.
   c. The NYISO shall confer with affected TOs. They shall jointly develop strategies to be followed in the event a contingency occurs. Strategies may include preparation for Quick Response Voltage Reduction and/or Load Shedding.

4.2 High or Low Voltage

Voltage control of the NYISO Secured Transmission System or the NERC Bulk Electric System as defined in Attachment A, Table A.2, shall be coordinated by the NYISO to provide adequate voltage at all times to maintain power transfer capability. When there is a Major Emergency due to voltage problems, the NYISO shall notify all TOs of the condition and shall direct the necessary corrective action.

a. If, having taken the actions above, the actual voltage at any bus listed in Attachment A, table A.2, remains below its pre-contingency low limit for 30 minutes or declines to a level below the mid-point between the pre and post contingency low limits and remains there for 15 minutes, then the NYISO shall

discuss the situation with the TO(s) to determine if corrective action could be taken following a contingency to prevent a System Voltage Collapse.

b. If it is anticipated that adequate time will not exist to prevent a Voltage Collapse following a contingency, then the NYISO shall direct the necessary corrective action, up to and including Load Shedding, to maintain a minimum voltage equal to the pre-contingency low limit.

c. If the actual voltage at any bus listed in Attachment A, Table A.2, declines below the post-contingency low limit and is indicative of a System Voltage Collapse, then the NYISO shall immediately order Load Shedding in the amount and at the locations deemed necessary to maintain a minimum voltage equal to the pre-contingency low limit.

4.3 Post-Contingency Voltage IROL Exceedances

Less Than 5%

a. If the post-contingency loading of an internal NYCA IROL interface or the post-contingency flow towards the NYCA on an inter-Reliability Coordinator interface exceeds the IROL limits associated with a voltage collapse by less than 5%, then measures shall be applied immediately to bring the loading to established limits within 15 minutes.

b. If, after taking corrective action, loadings are not below the limit within 15 minutes, then a Major Emergency shall be declared and corrective measures, which may include Load Relief, shall be initiated to bring the loading to established limits within 15 minutes.

c. NERC standards state the IROL flows must be below the limits within 30 minutes. In the event Load Shedding is required, to prevent a IROL violation, it must be ordered and implemented prior to 30 minutes from initial overload to ensure that limits have not been exceeded for greater than 30 minutes.

By 5% or More

a. If the post-contingency loading of an internal NYCA IROL interface or the post-contingency flow towards the NYCA of an inter-Reliability Coordinator interface exceeds the IROL limits associated with a voltage collapse by 5% or more, then a Major Emergency shall be declared immediately and corrective measures, which may include Load Relief, shall be initiated to bring the loading to established limits.

b. If loads are not below 105% of the limit within 15 minutes from the initial overload, then Load Relief measures must be instituted. NERC standards state the IROL flows must be below the limits within 30 minutes. In the event Load Shedding is required, to prevent a IROL violation, it must be ordered and implemented prior to 30 minutes from initial overload to ensure that limits have not been exceeded for greater than 30 minutes.

4.4 Operating Reserve Deficiency

Daily Operation

It is the responsibility of the NYISO to monitor Operating Reserve, both in a forecasted mode for the expected system peak for the day- ahead, in day, and as the day progresses.

Shortage Operating Reserve – Day-Ahead Forecast

If the Security Constrained Unit Commitment (SCUC) program indicates that NYISO will be short of Operating Reserves in the DAM, or if SCUC has already been completed and conditions then change such that the forecast indicates there will be an Operating Reserve deficiency, the NYISO will determine the action(s) listed below that are necessary:

In all of the following steps where additional capacity resources are being evaluated, the NYISO shall determine if each step is sufficient to eliminate the deficiency. In addition, all notifications made to TOs shall include approximate next-day starting time and duration associated with each curtailment step.

1. Perform a Supplemental Resource Evaluation (SRE) Request from the Market Information System (MIS) database of unaccepted/uncommitted bids for additional Reserve for the hours specified and commit/schedule the generation.
2. Initiate an e-mail to all Market Participants requesting additional (bids) generation for the specific category required.
3. Determine the amount of energy available from external NYCA Installed Capacity (ICAP) providers that were not selected in the DAM. Count energy associated with these ICAP providers from other Balancing Authorities to NYCA and NYISO Operating Reserve. Advise the affected external Reliability Coordinator accordingly.
4. Count energy associated with external energy sales by NYCA ICAP providers as NYISO Operating Reserve. Advise the affected external Reliability Coordinator accordingly.
5. Notify NYISO Customer Relations of predicted day-ahead system conditions.
6. Direct the TOs to notify the appropriate Market Participants to be prepared for the potential dispatch to UOLe for the next day.
7. Notify the appropriate Market Participants to prepare to make Special Case Resources (ICAP) resources available for the next day and count expected relief.
8. Notify the appropriate Market Participants to prepare to make the EDRP resources available for the next day and count expected relief.
9. Initiate an Emergency Energy Alert in accordance with NERC Standard EOP 002 for the next day via the RCIS; follow NPCC notification requirement, and notify NYISO External Affairs, PSC, and the NYS Department of Environmental Conservation (DEC).
10. Request the TOs to prepare to curtail non-essential company loads for the next day and to notify appropriate Market Participants to prepare to curtail non-essential company load for the next day.

- Request the TOs to notify interruptible customers in accordance with contractual agreements to prepare to make interruptible load available for curtailment for the next day.
- Request the TOs with Manual Voltage Reduction equipment to prepare to initiate procedures to reduce voltage by 5% for the next day.
- Request the TOs to contact large industrial and commercial customers to request voluntary curtailment of load the next day.
- Request the TOs to make general radio and TV appeals to the public to request voluntary curtailment of electric power.

11. Count Load Relief that can be implemented within 10 minutes using Quick Response Voltage Reduction as NYISO 10-minute reserve.

4.4.1 Shortage Operating Reserve New York City – Day-Ahead Forecast

New York State Reliability Council Reliability Rules

I-R2. Locational Reserves (New York City) Sufficient *ten (10) minute operating reserves* shall be maintained in the New York City (NYC) *zone* as follows:

a. The *ten (10) minute operating reserve* for *NYCA* shall be determined in accordance with Reliability Rules.
b. A percentage of the *ten (10) minute NYCA operating reserves* equal to the ratio of the NYC *zone* peak *load* to the statewide peak Load shall be required to be selected from *resources* located within the NYC *zone*.
c. NYC *zone ten (10) minute operating reserves* shall be maintained at all levels of dispatch, except as necessary to alleviate *emergency* conditions.

SCUC produces a daily report provided to the NYISO which indicates if the NYC zone is deficient in 10-Minute Reserve. The report is distributed with the daily SCUC documents within the NYISO. In the event that the NYISO sees a deficiency, the NYISO will notify Consolidated Edison of the operating day and hours that SCUC indicates a shortage of NYC 10-Minute reserve.

Actions that may be taken to establish NYC reserves for the hours of the deficiency:

- Initiate an SRE request e-mail soliciting bids for 10-Minute Reserve or energy for the hours deficient in NYC reserve.
- Determine if neighboring Reliability Coordinators have sufficient reserve and energy to support transaction to NYCA so that NYC reserves can be reestablished.
- Once bids are received, contact Consolidated Edison and have them SRE any additional units necessary to meet requirements.
- In the case there are insufficient bids to meet the NYC reserve requirement, make appropriate notifications to SCR and EDRP resources for the operating day in the NYC Zone to allow these resources to be counted.

- If the actions above do not satisfy the NYC reserve requirement, notify Consolidated Edison that Voltage Reduction is being counted to meet the NYC reserve requirement.

4.4.2 Shortage Operating Reserve – In Day

The NYISO will monitor the total operating capacity in day. The NYISO shall prepare the NYISO daily status report twice daily in anticipation of the morning peak and evening peak load. If deficiency in Operating Reserves is still forecasted, or if Real-Time Commitment (RTC) forecasts a shortage of reserve or energy for the next hour, the NYISO will take the steps not taken in the DAM that time permits to meet reserve requirements. Additionally, the NYISO will take any or all of the following actions as required based on the category of Operating Reverse Shortage:

In all of the following steps where additional capacity resources are being evaluated, the NYISO shall determine if each step is sufficient to eliminate the deficiency. In addition, all notifications made to TOs shall include approximate starting time and duration associated with each curtailment step.

1. Perform an SRE Request from the MIS database of unaccepted/uncommitted bids for additional Reserve for the hours specified and commit/schedule the generation.
2. Initiate an e-mail to all Market Participants requesting additional (bids) generation for the specific category required.

Declare Warning State

1. Determine the amount of energy recallable from external ICAP resources that was not selected in the DAM. Count energy available from external NYCA ICAP providers from other Reliability Coordinators to NYCA as NYISO Operating Reserve. Advise the affected Reliability Coordinators accordingly.
2. Count energy associated with exports from NYCA to other Reliability Coordinators by NYISO ICAP providers as NYISO Operating Reserve. Advise the affected Reliability Coordinators accordingly.
3. Notify NYISO Special Case Resources (ICAP) that they are counted toward NYISO Operating Reserves, and may be required to be activated during a specified period of time. (Estimated start and end time as announced.)
4. Notify EDRP participants that they are counted toward NYISO Operating Reserves, and may be requested to be activated during a specified period of time. (Estimated start and end time as announced.)
5. Notify NYISO Market Relations of predicted system conditions.
6. Notify the Market Participants to be prepared for the potential of using UOLe operation for the day and direct all Market Participants to follow basepoints.
7. Initiate an Emergency Energy Alert in accordance with NERC Standard EOP 002 for today via the Reliability Coordinators Information System (RCIS); Notify natural gas pipelines via notification requirements, follow DOE and NPCC notification requirements, notify NYISO External Affairs, PSC, and DEC.

8. Notify Market Participants to activate Special Case Resources (ICAP) to start at XXXX hrs and end at XXXX hrs.
9. Notify Market Participants to activate EDRP to start at XXXX hrs and end at XXXX hrs.

Declare Alert State

1. Request the TOs, via Emergency Hot Line, to curtail non-essential company loads and to notify appropriate Market Participants to curtail non-essential company loads.
    - Request the TOs, via Emergency Hot Line, to curtail interruptible customers in accordance with contractual agreements.
    - Request the TOs with Manual Voltage Reduction equipment, via Emergency Hot Line, to begin procedures to reduce voltage by 5%.
    - Request the TOs, via Emergency Hot Line, to contact large industrial and commercial customers to request voluntary curtailment of load.
    - Request the TOs, via Emergency Hot Line, to make general radio and TV appeals to public to request voluntary curtailment of electric power.
2. Count Load Relief that can be implemented within 10 minutes using Quick Response Voltage Reduction as NYISO 10-minute reserve.

4.4.3 Shortage Operating Reserve – Real Time

The NYISO will monitor the total Operating Reserve using the reserve monitor programs. If an operating shortage occurs, the NYISO will count SCR and EDRP available from prior notification and take any of the following steps that have not already been taken. Additionally, the NYISO will take any or all of the following actions as required based on the category of reserve shortage:

Following a Contingency

Based on the New York State Reliability Council rules:

Following a *contingency*, the *ten (10) minute operating reserve* shall be restored within thirty (30) minutes of the time that the *contingency* occurred or sooner if possible.

A Non-Contingency Based Shortage

Based on NPCC policy:

Each *Area* shall restore its *ten-minute reserve* as soon as possible, and within 90 minutes if it becomes deficient and the deficiency is not a result of a contingency that is a *reportable event*.

Each *Area* shall restore its *thirty-minute reserve* within four hours if it becomes deficient.

Declare Alert State

1. If deficient of 10-minute synchronized reserve direct all Market Participants to convert 30-minute non-synchronized reserve or 10-minute non-synchronized reserve to energy or 10-minute synchronized reserve.
2. If deficient of 10-minute reserve:
    - Direct all Market Participants to convert 30-minute reserve to energy or 10-minute reserve.
    - Activate use of UOLe limits.
    - Count or curtail energy associated with exports from NYCA to other Reliability Coordinators by NYISO ICAP providers as NYISO Operating Reserve based on the Reliability Coordinator's ability to have the transaction curtailed. Advise the affected external Reliability Coordinator accordingly.
    - Count the load reduction available from Quick Response Voltage Reduction as 10-minute reserve.
    - Purchase Emergency Energy from sources outside NYISO.

Declare Major Emergency

Direct TOs, via Emergency Hot Line, to notify the appropriate Market Participants that the NYISO is dispatching to UOLe and that they are to follow basepoints and to make all generator capability available.

Initiate an Emergency Energy Alert in accordance with NERC standard EOP 002 for today via the RCIS; follow NPCC notification requirement notify NYISO External Affairs, PSC, DEC, Gas Pipelines, and the Department of Energy(DOE) with form OE 417.

1. Notify the TOs via Emergency Hot Line and the appropriate Market Participants via the NYISO notification manager software that the NYISO has activated Special Case Resources (ICAP) if possible.
2. Notify the TOs via Emergency Hot Line and the appropriate Market Participants via the NYISO notification manager software that the NYISO has activated EDRP.
3. Alert other TOs, and Reliability Coordinators if applicable, that a sharing of reserves may be required.

4.4.4 Shortage of Meeting Load (Including the Inability to Reach a "0" ACE) – Real Time

Declare the Alert State

1. Initiate an Emergency Energy Alert in accordance with NERC Standard EOP 002.
2. Notify Gas Pipelines via e-mail.

Declare Major Emergency

1. Direct TOs, via Emergency Hot Line, to notify the appropriate Market Participants to go to UOLe limits, follow basepoints, and that the NYISO is in a generation alert.

2. Recall external energy sales provided by NYCA ICAP providers.
3. Notify the appropriate Market Participants to activate NYISO Special Case Resources, if possible.
4. Notify the appropriate Market Participants to activate EDRP, if possible.
5. Purchase Emergency Energy from sources outside NYISO.
6. Direct TOs, via Emergency Hot Line, to implement 5% Quick Response Voltage Reduction on a system wide basis.
7. Request neighboring Reliability Coordinators to implement Voltage Reduction to supply Emergency Energy, provided transmission loading permits.
8. Direct all TOs, via Emergency Hot Line, to notify appropriate Market Participants that the NYSDEC air emissions waiver is in effect and to go to generator maximum capability even it if may result in temporary exceedance of NOx RACT air emission limits and opacity requirements.
9. Direct all TOs, via Emergency Hot Line, to shed load immediately in sufficient amounts to maintain tie loadings within limits, return the NYCA ACE to zero within 10 minutes attempting to return the system frequency to 60 hertz in accordance with NYISO criteria.

4.5 IROL Stability Limit Violation

Less Than 5%

a. If the loading of an internal NYCA IROL interface or the power flow towards the NYCA on an inter-Reliability Coordinator IROL interface exceeds the NYCA IROL stability limit by less than 5%, then measures shall be applied immediately to bring the loading to established limits within 15 minutes.
b. If, after taking corrective action, loadings are not below the IROL stability limit within 15 minutes, then a Major Emergency shall be declared and corrective measures, which may include Load Relief, shall be initiated to bring the loading to established limits within 15 minutes.
c. NERC standards state the IROL flows must be below the limits within 30 minutes. In the event Load Shedding is required, to prevent a IROL violation, it must be ordered and implemented prior to 30 minutes from initial overload to ensure that limits have not been exceeded for greater than 30 minutes.

By 5% or More

a. If the loading of an internal NYCA IROL interface or the power flow towards the NYCA on an inter-Reliability Coordinator IROL interface exceeds NYCA IROL stability limit by 5% or more, then a Major Emergency shall be declared immediately and corrective measures, which may include Load Relief, shall be initiated to bring the loading to established limits.
b. If loadings are not below 105% of the IROL stability limit within 15 minutes from the initial overload, then Load Relief measures must be instituted. NERC standards state the IROL flows must be below the limits within 30 minutes. In

the event Load Shedding is required, to prevent a IROL violation, it must be ordered and implemented prior to 30 minutes from initial overload to ensure that limits have not been exceeded for greater than 30 minutes.

4.6 High/Low Frequency

Low Frequency

A sustained low frequency of 59.90 Hz is an indication of major load generation imbalance, in which case the NYISO shall declare a Major Emergency. The NYISO will take appropriate action, to correct any under-generation and bring the NYISO ACE back to zero

If during a Major Emergency resulting from a low frequency condition caused by load-generation imbalance within the NYCA, additional NYISO generation is lost, the NYISO shall immediately order Load Shedding to alleviate the imbalance.

When the frequency decline is so rapid as to preclude analysis and communication amongst the NYISO and TOs, then the following procedures will apply up to permissible LTE ratings:

a. Under Frequency Load Shed (UFLS) Implementation Plan for the Eastern Interconnection Portion of NPCC as defined in Attachment A Table A.7.
b. 58.5 Hz – If frequency is still declining, then all TOs shall take such steps as are necessary, including separating units to preserve generation, minimize damage and service interruption.

Rapid Frequency Decline

In the event that the frequency decline is so rapid as to prevent operator action, automatic facilities exist to achieve the required Load Shedding as described above, without regard to transmission loading.

High Frequency

A sustained high frequency of 60.10 Hz is an indication of major load generation imbalance, in which case the NYISO shall declare a Major Emergency. The NYISO will take appropriate action to correct any over generation and bring the NYISO ACE back to zero.

4.7 Overgeneration

Over generation is defined as a condition where minimum generation is greater than the minimum system load requirements. Actions are taken to avoid the export of excess energy over NYISO tie lines with neighboring Reliability Coordinators.

To the extent that it is possible to anticipate over generation situations, the NYISO shall make every effort to give advance notice. However, even if a forecast of an overgeneration situation has not been issued, the NYISO shall implement the actions contained in this section, as required.

NYISO Actions

During periods of NYCA actual overgeneration, the NYISO shall take actions in the following order to the extent needed, when system conditions and time permit.

1. Request all over generating suppliers that are contributing to the problem to adjust generation to match their schedules.
2. Reduce applicable NYCA dispatchable generation to minimum operating limits (through RTD) and shall suspend regulating margins if required.
3. Request Internal Generators to voluntarily operate in the “manual mode” below minimum dispatchable levels.
4. Attempt to schedule variable load, including pumped hydro resources to alleviate the problem.
5. If the accumulated inadvertent interchange account is negative and the time error is negative (slow clocks), the NYISO shall unilaterally pay back inadvertent interchange through an offset, in accordance with NERC.
6. Request reduction or cancellation of all transactions that contribute to the violation.
7. If the over generation violation persists, the NYISO shall declare a Major Emergency. The NYISO shall then de-commit applicable internal Generators based on their minimum generation bid, in descending order, until the violation is eliminated.

The NYISO prepares and issues to the NYISO Operating Committee a report of the circumstances necessitating generation reductions.

5. REDUCING TRANSMISSION FLOWS

This section discusses the reduction of transmission flow Exceedances.

5.1 Procedure

This procedure defines the steps to be taken by the NYISO to reduce transmission system flows that are causing or may cause exceedances of thermal, post contingency voltage IROL or IROL stability criteria on NYISO Secured Transmission System or the NERC Bulk Electric System facilities.

This procedure is intended to be used to promote system security, and it is not intended that it be used in the resolution of commercial disputes. The method outlined below is intended to properly allocate the reduction of transmission flows to relieve exceedance.

NYISO Actions

When there is a security exceedance that requires reduction in transmission flow, the NYISO shall take action in the following sequence and to the extent possible, when system conditions and time permit.

1. Implement all routine actions using phase angle regulator tap positions, where possible.
2. Request all overgenerating suppliers that are contributing to the problem to adjust their generation to match their schedules.
3. Request voluntary shifts on generation either below minimum dispatchable levels or above Upper Operating Limit Emergency (UOLe) levels to help relieve the violation.
4. Reduce or cancel all transactions that contribute to the violation.
5. As system conditions allow the NYISO will re-evaluate all or a portion of the transactions that were curtailed.

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6. RESTORATION STATE

This section describes the implementation of the New York Independent System Operator (NYISO) System Restoration Plan (SRP). The *NYISO System Restoration Manual* (available from http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20) addresses the development and maintenance of the procedures, documentation, training, and testing related to New York Control Area Restoration Plan.

6.1 Definition of the Restoration State

The Restoration State exists following a system disturbance affecting the NYS Power System where one or both of the following conditions exist:

- An area within the NYCA becomes islanded
- Customer load becomes interrupted, following a disturbance affecting the NYS Power System

Immediate actions are required to return the NYS Power System to the Normal State. The specific conditions defining each state are contained in Attachment B of this Manual.

6.2 Restoration Criteria

6.2.1 Scope

The NYISO restoration procedures are based on restoring a backbone of high-voltage lines, while allowing operators flexibility to adjust the restoration path for actual system conditions. From this backbone there are a multitude of options to restore transmission, access available generation, and coordinate with the restoration efforts with the New York transmission owners and neighboring areas, Reliability Coordinator.

6.2.2 Strategy

Prompt restoration of the NYCA total customer load is best accomplished by the restoration of the NYS Power System. The New York Control Area (NYCA) Restoration Plan calls for the energization of a 345-kV and 230-kV transmission backbone from Niagara, St Lawrence, and Gilboa Black Start facilities. This transmission backbone consists of three major paths: Buffalo to Utica to Albany to New York City; Massena to Utica; and Buffalo to Binghamton to Albany. From this backbone there are a multitude of options to restore transmission, access available generation, and coordinate with the restoration efforts with the TOs and neighboring Reliability Coordinators. Because the exact extent or nature of a disturbance cannot be predicted, procedures are prepared as general guidelines. These procedures are contained in Attachment B.

The Basic Minimum Power System to be energized consists of the Black Start facilities and the key facilities identified in Attachment B.

6.2.3 Priorities

The following operations shall have the highest restoration priority:

- Energizing the backbone transmission path of the NYS Power System. (Priority shall be given to energizing the Gilboa to Staten Island and Long Island path, while simultaneously restoring from Niagara and St. Lawrence Black Start facilities.)
- Synchronizing the NYS Power System with the interconnection.
- Restoring off-site power supplies to nuclear power plants.

The next priority shall be load restoration. If there is limited energy available within the NYCA, preference shall be given to generating station startup, followed by the restoration of the high-density load portions of the system.

6.2.4 Responsibilities

The NYISO shall maintain the function of Balancing Authority for all portions of the NYCA system synchronized to facilities connected to the backbone transmission path. All TO load and generation restoration on the system under NYISO's Balancing Authority shall be coordinated through the NYISO. Some customer load may be picked up during the early stages of restoration to maintain stability and voltage levels, but priority must be assigned to the restoration of the transmission backbone and major transmission ties.

Each TO shall have a restoration procedure to meet local priorities. During restoration, each TO shall coordinate restoration within its own area on portions of the system isolated from the NYISO Black Start facilities and/or ties to neighboring Reliability Coordinators. TO load restoration must not delay the restoration of inter- and intra-area ties. The NYISO may order Load Shedding as appropriate to ensure that generation capacity is available to achieve the restoration priorities where load additions are impeding the NYS Power System restoration.

During the Restoration State, the NYISO may reserve blocks of generation for incremental deployment up to 700 MW of generation capacity to facilitate restoration of the Con Edison NYC area 345-kV transmission path from Sprainbrook/Dunwoodie substations to Freshkills substation.

If all communication is lost between the PCC and TOs, the TOs shall proceed to restore the NYS Power System using inter-company communication facilities to coordinate all aspects of the restoration.

6.3 Responses to the Restoration State

When a Restoration State is declared by the NYISO, the NYISO and the Transmission Owners (TOs) shall perform the actions described in this section.

If a disturbance occurs in which a portion of the NYS Power System becomes isolated or shut down, the steps defined in the procedures that are applicable to the disturbance shall be used in the restoration of facilities within the area. Load Shedding procedures have been modified during system restoration events and are detailed in section 7.4.

NYISO Actions

The NYISO shall perform the following:

1. Determine that the NYCA is in the Restoration State and notify all TOs.
2. Restore transmission facilities employing the Restoration Procedures and Diagrams found in Attachment B.
3. Coordinate the closing and energizing of inter-company and inter-Control Area transmission ties.
4. Monitor power flow, frequency, and voltage and order appropriate actions by TOs to operate the NYS Power System within NYISO operating criteria.
5. Expedite and coordinate the synchronization of separated areas to adjacent systems within the NYCA and in neighboring Reliability Coordinator.
6. Schedule energy transfer, as necessary, with neighboring Reliability Coordinators to facilitate restoration, emphasizing Generator startup and critical loads.
7. Request and permit the restoration of load that has been shed previously when there is sufficient generation and transmission capacity available to maintain the following conditions:
    - nominal frequency of 60 Hz
    - voltages within limits
    - transmission line loading at or below emergency transfer limits
8. Maintain continuous communication with all neighboring Reliability Coordinators impacted by the restoration actions using the most readily available communication device.
9. Communicate periodically with all TOs via the Emergency Hot Line System to provide status reports regarding the restoration actions and the status of the NYCA.
10. Authorize load restoration on the portions of the system electrically connected to the NYISO Black Start facilities and/or neighboring Reliability Coordinators.
11. Authorize generation starts and dispatch on the portions of the system electrically connected to the NYISO Black Start facilities and/or to the neighboring Reliability Coordinators' system.

Transmission Owner Actions

The TOs shall perform the following:

1. Execute orders received from the NYISO to restore the NYS Power System.
2. Notify the NYISO as soon as possible, and periodically thereafter, of system status, including generation, transmission, load, and other appropriate information.
3. In accordance with the TOs' restoration procedures, protect system facilities and make them ready to be energized and begin to energize internal facilities necessary to restart generation, supply critical load, and make inter-company ties available for service.
4. Prior to proceeding with switching, isolate from the system all buses that will become energized as a result of these procedures to avoid the inadvertent pick-up of customer load, except where load restoration is required to stabilize voltage levels.

5. Notify the NYISO of internal system conditions, such as voltage problems, transmission overloads, and local mismatch of generation and load, that must be corrected prior to completing the NYISO requests.
6. Re-establish interconnected operation with neighboring systems with the permission of the NYISO.
7. Coordinate with the NYISO any restoration actions that impact other TOs and Reliability Coordinators.
8. Coordinate with the NYISO to provide startup power to generating facilities.
9. Synchronize the system with the restored NYS Power System under the direction of the NYISO as each TO system completes the restoration of its local facilities.
10. Continue to implement the TOs' restoration plans, subject to the NYISO coordination.
11. Complete the restoration of all customer load, in accordance with the TOs' restoration plans and in coordination with the NYISO

Generator Operator (GOP) Actions

The GOPs shall perform the following:

1. Execute requests received from the Transmission Owner.
2. Notify the Transmission Owner as soon as possible, and periodically thereafter, of facility status and other appropriate information.
3. Immediately upon de-energization of a Black Start facility, initiate Black Start procedures.

6.4 Communications during Restoration

6.4.1 Normal and Emergency Communications Procedures

Normal and emergency communications procedures and protocols for use during Restoration State recovery actions are found in the sections 1.4 and 1.5 of this Manual.

6.4.2 Loss of Communications with the NYISO

If all communication is lost between the Power Control Center and TOs, the TOs shall proceed to restore the NYS Power System using inter-company communication facilities to coordinate all aspects of the restoration according to the procedures in section 6 of this Manual.

6.4.3 Incident Command Structure (ICS) Protocol

The NYISO has developed an internal procedure for establishing an Incident Command Structure protocol in order to manage and prioritize off-floor communications during bulk power disturbances. Key elements of this protocol have been shared with appropriate entities for coordination of communication during system recovery.

6.5 Updating Restoration Documentation

The update and review process applied to the NYCA restoration plan is addressed in the *NYISO System Restoration Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20).

Due to the Critical Electric Infrastructure Information (CEII) contained in Attachment B of this *Emergency Operations Manual*, distribution of this attachment is restricted. Revisions to Attachment B shall be performed as the NYISO or TOs deem necessary due to significant changes to the power system network or modeling. Following the review, the NYISO and TOs will update the System Restoration Plan (SRP).

NYISO staff shall make the necessary changes to update Attachment B and shall distribute it to the NYCA control centers.

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7. LOAD RELIEF

This section describes the means for reducing load.

7.1 Load Curtailment

The NYISO staff shall forecast the likelihood of occurrence of States other than the Normal State as far in advance as possible. If it is predicted that Load Relief, either by Voltage Reduction or Load Shedding, may be necessary during a future period, all Transmission Owners (TOs) shall be notified and preparatory arrangements shall be made for corrective measures requiring substantial lead-time including the following types of load curtailment:

a. Curtailment of interruptible load
b. Manual (local) Voltage Reduction
c. Curtailment of non-essential Market Participant load
d. Voluntary curtailment of large LSE customers
e. Public appeals

Table C.1 of Attachment C defines the Load Relief available through these measures.

1. External loads (bilateral exports and external LBMP bid load) may be curtailed under a NYISO Alert State or Major Emergency State to avoid involuntary load curtailment (due to a supply deficiency) of Internal NYCA Load.
2. Internal loads may be curtailed under the NYISO Major Emergency State to solve transmission security exceedance.
3. To solve transmission security exceedances, applicable NYISO Curtailment Steps including Transmission Loading Relief (TLR) procedures will be invoked (as described in the *NYISO Transmission and Dispatching Operations Manual*, available from the NYISO Web site at the following URL: http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20)..
4. To avoid involuntary 5% Quick Response Voltage Reduction and/or Load Shedding internal to NYCA (due to a supply deficiency), only external loads served by the LBMP market or by bilateral transactions from NYCA ICAP providers (up to the amount of ICAP it provides to NYCA) may be curtailed (on a pro rata basis).
5. External loads served by bilateral transactions from non-NYCA ICAP providers (or from the non-NYCA ICAP capacity portion of a NYCA ICAP provider) will not be curtailed (to avoid involuntary 5% Quick Response Voltage Reduction and/or Load Shedding internal to NYCA) for that portion of the transaction that is physically served by that supplier (see example below).

Example of Rules 4 and 5 (All Amounts are in MW)					
Supplier's Attributes	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**
DMNC Rating	100	100	100	100	100
I = ICAP Being Provided to NYCA	50	50	50	50	50
A = Total Actual Output	50	0	100	50	100
T = Export Transaction	100	100	100	50	20
C = Amount of the Export Transaction that can be Curtailed	100	100	50	50	0

Rule 4 and 5 can be described as follows:
C = MAX [T -MAX (A - I, 0), 0]

C = The amount that the export transaction can be curtailed is equal to MAX (A,B) = the greater of A or B
T = The Amount of the Export Transaction
A = The Actual Output from the Supplier
I = The Amount of NYCA ICAP being provided by this Supplier

> ***Note:*** For a supplier that has sold ICAP into the NYISO auction, its "I" will be derated on a pro rata basis to account for the amount of ICAP sold in the auction to external LSEs

6. With the exception of the stipulations in Rules 4 and 5 above, load curtailments will not differentiate between loads served by bilateral transactions and LBMP bid loads. Invocation of Rules 4 and 5 above with respect to external loads in a neighboring Control Area presume reciprocal rule treatment by that Control Area.
7. Both internal and external Day-Ahead loads bids that are curtailed will be refunded the applicable Day-Ahead LBMP. A bilateral transaction in which loads are curtailed will be considered a financial curtailment so that any applicable Day-Ahead Transmission Usage Charge (TUC) will be refunded.

7.2 Voltage Reduction

Table C.1, Attachment C defines the amount of Load Relief available through Quick Response Voltage Reduction.

The following Voltage Reduction procedures define the actions to be taken by the NYISO, to include procedures to assist neighboring Reliability Coordinators.

1. When a shortage of Operating Reserve is predicted and adequate time is available to complete Manual Voltage Reduction procedures, such procedures shall be accomplished prior to implementing Quick Response Voltage Reduction.
2. Load Relief attainable by Quick Response Voltage Reduction is classified as 10-minute Reserve after all available capability is used. Emergency Transfer Criteria may be invoked to deliver reserves. This procedure addresses the NYISO actions to implement Quick Response Voltage Reduction.

If, after the above action a shortage of 10-Minute Reserve still exists, the NYISO shall declare a Major Emergency and shall direct that Load Relief procedures be implemented as follows:

a. Direct the TOs to implement Quick Response Voltage Reduction up to 5%.
b. If NYISO resources are still less than NYCA Load, request other Reliability Coordinators to go into Voltage Reduction and obtain Emergency Energy from them to avoid Load Shedding
c. If further load curtailment is required, refer to section 4 of this Manual.
d. If NYISO resources still do not match NYCA load, refer to section 4 of this Manual.

3. The NYISO will reduce voltage to the extent transmission limitations permit, for neighboring Reliability Coordinators already in Voltage Reduction, to assist in preventing the neighboring Reliability Coordinator from interrupting firm customer load.
4. When implementation of Load Relief measures is indicated the NYISO shall have the authority to order 5% Quick Response Voltage Reduction in those areas where such action will reduce transmission overloads or transient stability transfer limit exceedances.

Authority

The NYISO has the responsibility for administering the Voltage Reduction policy and the NYISO has the authority to direct the actions required as set forth above.

Internal loads may be curtailed under the NYISO Major Emergency State to solve a transmission security exceedance.

7.3 Load Shedding

It is the responsibility of all TOs to shed load as ordered by the NYISO to assist other TOs. A TO is responsible for Load Shedding within the geographic area of its Transmission District in the following ratio:

Load Shedding Ratio

$$\frac{\text{Estimated Peak Load in Transmission District for Capability Period}}{\text{Sum of Transmission Owners Estimated Peak Loads for Capability Period}}$$

See Attachment C for Load Shedding allocation by a TO for the following situations:

- Load reduction by the entire NYCA (Table C.2)
- Load reduction to relieve specific transmission interfaces (Table C.3)

Each Area must be capable of carrying out the following Load Shedding capabilities:

- Based on UFLS Implementation Plan for the Eastern Interconnection Portion of NPCC as defined in Attachment A Table A.7.
- Load Shedding of at least 50 percent of its load in 10 minutes or less. Insofar as practical, the first half of the Load shed manually should not include any load that is part of any automatic Load Shedding plan

The New York Power Authority (NYPA) loads are largely wholesale deliveries to other TOs and reduction of such deliverables is not appropriate. Other NYPA loads are supplied by wheeling power over the transmission facilities of other TOs. The NYPA agrees that these wheeled loads may be included in the Load Shedding plans of the wheeling TO on the same basis that the TO applies to its own loads. The NYPA has ad hoc arrangements with its directly served principal industrial customers to reduce load under certain conditions. Such reduction, to the extent that it alleviates an Emergency condition, probably is implemented before widespread reduction of other loads.

NYISO Actions

The NYISO shall perform the following:

1. Order the appropriate TO(s) to shed load, using the Emergency Hot Line System.
2. Order the appropriate TO(s) to shed load and specify the amount of load to be shed.
3. Activate the Load Shed Alarm System for the corresponding TO(s).

7.4 Load Shedding During System Restoration

For all system conditions except system restoration, the existing protocol is to shed load as a percentage of TO peak load to NYCA load, as defined in this Manual, section 7.3, "Load Shedding." During system restoration, the distribution of system load may not be as defined by peak load conditions.

During system restoration, the NYISO shall determine the existing load in each TO area. This load distribution should be used to determine the appropriate Load Shedding allocation to each TO based on their current load. The preferred method is to use the Load Shed Ratio listed below.

Load Shed Ratio during Restoration:

$$= \frac{\text{Existing Load in The Transmission District}}{\text{Sum of Transmission Owners Existing Load}}$$

7.5 Load Shed Alarm System

This section describes the NYISO Load Shed Alarm System and the procedures for testing it. The Load Shed Alarm System reinforces any verbal order to shed load and alerts operating personnel at the TO Energy Control Centers that an order to shed load has been given to the TO. The Load Shed Alarm System is designed to meet the recommendations of the NYS PSC and the Task Force Report on the System Disturbance of July 13, 1977.

7.5.1 Operating the Load Shed Alarm System

The Load Shed Alarm System operates a flashing strobe light in each TO Energy Control Center. The NYISO activates the Load Shed Alarm System for a TO by executing on the poke point associated with the TO’s display. When the NYISO activates the Load Shed Alarm System for a TO, the following events occur:

- A Load Shed Alarm signal is sent to the appropriate TO. It currently takes up to 8 seconds for each TO to receive the Load Shed Alarm signal at the TO's Energy Control Center where it activates a strobe light.
- When the Load Shed Alarm signal is sent to the TO, the poke point on display associated with the TO inverts and changes color from red to green for approximately 15 seconds.
- A Load Shed Alarm message is logged at the PCC when the Load Shed Alarm System is activated.

Due to the intended use of this system, sophisticated safeguards and redundancy are not incorporated in its design. Under certain abnormal conditions, the strobe light can operate erroneously. If such a failure occurs, the PCC shall be notified immediately. It is stressed, therefore, that no Load Shedding action shall be taken by TOs without prior verbal notification of the Emergency situation from the NYISO specifying the amount of load to shed.

7.5.2 Testing the Load Shed Alarm System

The NYISO shall initiate a test of the Load Shed Alarm System on a weekly basis. The NYISO shall report any trouble on the Load Shed Alarm System to the service provider. TOs shall report any problems to the NYISO.

NYISO Actions

The NYISO shall perform the following:

1. Notify a TO that a test of the Load Shed Alarm System is being conducted.
2. Activate the Load Shed Alarm System to that TO.
3. Notify the TO that the test is concluded.
4. Test the remaining TOs' Load Shed Alarms in similar fashion.
5. Log the time and date of the test, as well as any pertinent comments, in the NYISO Log.

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8. CONTROL CENTER AND COMMUNICATIONS FACILITIES

This section describes the NYISO Control Center Communications during normal and abnormal conditions.

8.1 Overview

Interim operation of the NYISO is defined as that period of time when voice communication between the NYISO and the TO Energy Control Centers is lost. This section describes the procedures for interim operation of the NYCA during the emergency transfer of control after an evacuation of the PCC and prior to activation of an ACC. This policy shall also apply to any period when all voice communication between the TOs and the NYISO is lost due to equipment failure.

The procedures in this section are designed to ensure that the security of the NYS Power System is adequately maintained during periods of interim operation and that a minimum acceptable level of coordination of operation among the TOs and neighboring Reliability Coordinators is maintained. The NYISO has the following primary objectives during this period:

- Maintain system security.
- Maintain the balance of load and generation with existing interchange schedules until TO communication with the PCC or the ACC can be re-established.

8.2 Responsibilities and Authority

The Consolidated Edison System Operator and the National Grid Security Operator have the authority and the responsibility to assume the role of Designated NYISO Coordinators as described in this section.

Consolidated Edison Actions

1. Coordinate the Southeast New York (SENY) TOs:
    - Consolidated Edison
    - Long Island Power Authority (LIPA)
    - Orange and Rockland
    - Central Hudson
2. Coordinate with the following neighboring Reliability Coordinator:
    - PJM Interconnection, L.L.C.
    - ISO New England
3. Coordinate with National Grid.

National Grid Actions

1. Coordinate the Upstate New York (UPNY) TOs:
    - National Grid
    - New York State Electric & Gas
    - Rochester Gas and Electric
    - New York Power Authority (NYPA)
2. Coordinate with the following neighboring Reliability Coordinators:
    - IESO
    - Hydro Quebec
3. Coordinate with Consolidated Edison.

Transmission Owner Actions

1. Operate at all times in accordance with the NYISO Operating Policies and Procedures stated in this Manual.
2. Coordinate operations with respective Designated NYISO Coordinators under the policies and procedures defined in this Manual and the *NYISO Transmission and Dispatching Operations Manual* (available from the following URL: http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20).

8.3 Invoking Interim New York Control Area Operation

Interim NYCA Operation procedures may be invoked by the NYISO if it is possible and if time permits or may be invoked by Consolidated Edison and National Grid if voice communication with the NYISO is lost.

8.3.1 Loss of Voice Communications

Normal operations require voice communication between the TOs and the NYISO at least once each hour. If it is determined by the Consolidated Edison System Operator and the National Grid Security Operator that voice communication between the NYISO and the TOs has been lost, Consolidated Edison and National Grid shall perform the actions described here.

Consolidated Edison and National Grid Actions

1. Assume the role of Designated NYISO Coordinators.
2. Declare a Major Emergency State.
3. Immediately, notify their respective TOs and neighboring Reliability Coordinators of the Major Emergency State and of their responsibilities as Designated NYISO Coordinators.

4. Advise their respective neighboring Reliability Coordinators that the Northeast Power Coordinating Council (NPCC) Reserve Sharing (SAR) is terminated and that current schedules with them should be maintained if possible.
5. Coordinate NYCA Operations with the TOs and Reliability Coordinators as listed in this section.

During other than normal working hours, Consolidated Edison and National Grid shall notify one of the members of the NYISO Operations Management Staff.

8.3.2 Evacuation Procedure

If it becomes necessary to evacuate the PCC, the NYISO shall follow the procedure described here, to the extent time permits.

NYISO Actions

The NYISO shall perform the following:

1. Declare a Major Emergency.
2. If possible, notify all TOs, using the Emergency Hot Line System of the following information and instructions:
    - The PCC is being evacuated
    - Transmission Owners shall follow their last Desired Net Interchange (DNI) until further notice from either the Designated NYISO Coordinator or the NYISO ACC.
    - All scheduled outages that affect the NYS Power System are canceled.
    - Transmission Owners shall begin Interim NYCA Operation according to the procedures in this Manual.
    - Transmission Owners shall prepare for establishment of the NYISO ACC.
3. Notify the NYISO Information System (IS) Staff of the following information and instructions:
    - Operations will be conducted from the ACC.
    - Report to the NYISO ACC.
    - Prepare the ACC computer for on-line operation.
4. After normal working hours, notify one of the NYISO Operations Management Staff.
5. Notify the Guilderland Police that the PCC is being evacuated and state the nature of the Emergency.
6. Fax the following displays to Consolidated Edison and National Grid:
    - Security Monitor
7. Take the following documents and equipment to the ACC:
    - All current log sheets
    - All current outage sheets
    - Daily operating limits summary
    - Security monitor display

- Cellular telephone from the NYISO Shift Supervisor position

8. If time does not permit all notifications to take place before evacuation, make the notifications as soon as possible after arrival at the ACC.

Shift Staff

9. Notify PJM, IESO, ISO-NE, and HQ of the following information:
   - Next hour schedules will remain the same until further notice from NYISO or a Designated NYISO Coordinator.
   - The identity of the NYISO individual or Designated NYISO Coordinator individual that will contact them during the period of Interim NYCA Operation prior to staffing the ACC.

8.4 Interim New York Control Area Operation

This section describes the procedures followed by the Designated NYISO Coordinators and the TOs during the Interim NYCA Operation period.

8.4.1 Initial Operation

Immediately upon beginning the Interim NYCA Operation period, the Designated NYISO Coordinators shall establish Total Operating Reserve Requirements for the NYCA in accordance with the operating policy stated in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20) and shall determine the category and amount of external bilateral transactions.

Transmission Owner Actions

All TOs shall initially follow their last DNI, as determined by NYISO Real Time Dispatch (RTD) or TO Directed Dispatch, and regulate their systems to that DNI. The DNI shall include the net of the current firm and non-firm bilateral transactions.

Designated NYISO Coordinator Actions

1. Immediately upon assuming the responsibilities of Designated NYISO Coordinators, Consolidated Edison and National Grid shall poll their respective TOs and record the following data on the forms in Attachment E:
   - Each Member's DNI for the last run of RTD (DNI Change Log)
   - Each Member's 10-Minute Reserve and Total Operating Reserve (Reserve Allocation Survey). Reserves should reflect the most conservative estimate over the next half hour period.
2. The DNI shall be recorded on the attached DNI Change Log for the following neighboring Reliability Coordinators' proxy busses:
   - IESO-NYISO-AC
   - ISO-NE-NYISO-AC
   - ISO-NE-NYISO Cross Sound Cable

- ISO-NE-NYISO 1385
- PJM-NYISO-AC
- PJM-NYISO Neptune
- PJM-NYISO VFT
- HQ-NYISO 7040
- HQ-NYISO Cedars

3. With the data obtained above Consolidated Edison shall develop the following sums for SENY, and record them on the attached forms:
    - 10-Minute Reserve in SENY (Reserve Allocation Survey)
    - Total Operating Reserve in SENY (Reserve Allocation Survey)
    - Desired Net Interchange for SENY (DNI Change Log)
4. Similarly, National Grid shall develop the following sums for UPNY and record them on the attached forms:
    - 10-Minute Reserve in UPNY (Reserve Allocation Survey)
    - Total Operating Reserve in UPNY (Reserve Allocation Survey)
    - Desired Net Interchange for UPNY (DNI Change Log)
5. The Designated NYISO Coordinators shall exchange the reserve and DNI information determined for the SENY and UPNY Transmission Owner Systems.
6. The Designated NYISO Coordinators shall determine the availability and location of reserves.
7. The Designated NYISO Coordinators shall discuss reserve pickup strategy for the largest contingency in both UPNY and SENY.
8. The Designated NYISO Coordinators shall agree on the following reserve requirements and record them on the Reserve Allocation Survey:
    - 10-Minute Reserve Requirement for the NYCA, which shall be equal to the most severe contingency in the NYCA, including any single interruptible purchase.
    - Total Operating Reserve Requirement for the NYCA, which shall be equal to 1.5 times the most severe capacity contingency.
9. The Designated NYISO Coordinators shall request out-of-service NYS Transmission System lines restored, where possible, if the restored transmission lines would enhance system security. Additionally, lines scheduled to be taken out of service shall be deferred, where possible, if system security would be enhanced by keeping the transmission line in service.
10. Where it is possible and desirable, generating units scheduled to come off line shall be delayed.

8.4.2 Continuing Operation

At all times, the Designated NYISO Coordinators shall ensure that the NYCA has adequate reserves. The Designated NYISO Coordinators shall monitor the actual reserves of each TO during Interim NYCA Operations. Reserves should reflect the most conservative estimate over the next half hour period.

The Designated NYISO Coordinators shall coordinate schedule changes within the NYCA. Desired Net Interchange changes may be required for one or more of the following reasons:

- As the result of a reserve pick up.
- Changes required by neighboring Reliability Coordinators.
- The inability of a TO(s) to meet its DNI as a result of changes made for security reasons.

Whenever DNI changes are required, every effort should be made to make a reasonable smooth transition, even if this is at the expense of economic operation. All efforts shall be made by each TO and by the Designated NYISO Coordinators to minimize schedule changes during the period of Interim NYCA Operation. This shall include pumped storage hydro schedules and the output levels of large base-load units.

Designated NYISO Coordinator Actions

1. Poll their respective TOs at least every half hour and exchange totals as described for initial operation.
2. If at any time the NYCA becomes deficient in 10-Minute Reserve or Total Operating Reserve, the Designated NYISO Coordinators (independently) shall take one or more of the following actions:
    - Request a TO(s) to convert Total Operating Reserve to 10-Minute Reserve.
    - Request a neighboring Reliability Coordinator to provide capability on an emergency basis.
3. Coordinate all reserve pickups for loss of large NYCA units, significant reductions in NYCA imports, and large negative Area Control Errors. The Designated NYISO Coordinators shall determine reserve pickup for losses greater than 300 MW according to the following guidelines:
    - Within the NYCA, primary consideration shall be given to the most responsive sources, regardless of economics, such as cutting external transactions or modifying pumped storage hydro operation. The actual 10-Minute Reserves in the Reserve Allocation Survey E-3 and E-4 provided in Attachment E shall be used as a guide.
    - If the loss cannot be picked up in the NYCA, the Designated NYISO Coordinators shall request neighboring Reliability Coordinator to provide emergency assistance.
4. Coordinate all required changes to external transactions. The Designated NYISO Coordinators shall make every effort to balance these changes with anticipated changes in NYCA load, or generation, or both.
5. Determine DNI changes, as necessary, and notify each respective TO. Record the DNI changes on the attached DNI Change Log, noting the time, the individual TO DNIs, and a brief description of the reason for the change.
6. Coordinate assistance, if requested, for a TO that is unable to maintain adequate control.
7. Coordinate actions with TOs related to the security of the NYS Power System.

8. Coordinate actions with TOs related to voltage control, phase shifter, capacitor, and reactor operations.
9. Coordinate NYS Power System Restoration in accordance with the procedures in the Restoration Procedures section 6.3 of this Manual.
10. Solar magnetic disturbance notices are transmitted from PJM to Consolidated Edison. Consolidated Edison shall relay the messages to ISO-NE, National Grid, and Consolidated Edison's respective TOs. National Grid shall relay the messages to IESO and National Grid's respective TOs.
11. Relay notification of severe weather warnings received from a Transmission Owner to their respective TOs and to the other Designated NYISO Coordinator.
12. Individually, log all orders and events that occur while operating under this procedure, using local logging procedures.

Transmission Owner Actions

The TO shall perform the following:

1. Inform the appropriate Designated NYISO Coordinator of any changes in their actual operating reserves. Reserves should reflect the most conservative estimate over the next half hour period.
2. Inform the appropriate Designated NYISO Coordinator in the event of a loss and, if it has sufficient reserves, the TO shall attempt to pick up the loss on its own.
3. Maintain their own area control errors.
4. Maintain NYS Power System security under the coordination of the Designated NYISO Coordinators.
5. Coordinate voltage control, phase shifter, capacitor, and reactor operations with each other and with the Designated NYISO Coordinators.
6. Notify the appropriate Designated NYISO Coordinator of severe weather warnings.

8.5 Alternate Control Center Operation

This section describes how the NYISO establishes ACC Operations and operates the NYCA from the ACC. When instructed by NYISO Operations, the NYISO IT Staff will make the ACC Primary Control Center.

8.5.1 ACC Operation

If the ACC computer system is fully operational, the NYISO performs the actions described here:

NYISO Actions

The NYISO Operating Personnel shall perform the following:

1. Verify RTC/RTD are running after the ACC computer system has been initialized.
2. Check the PCs for operation.
3. Notify all TOs that the ACC is operational and that NYISO control will be assumed from the ACC.

4. The NYISO shall notify the following neighboring Reliability Coordinators that the ACC is operational and shall verify current schedules with them on appropriate proxy busses:
    - IESO-NYISO-AC
    - ISO-NE-NYISO-AC
    - ISO-NE-NYISO Cross Sound Cable
    - ISO-NE-NYISO 1385
    - PJM-NYISO-AC
    - PJM-NYISO Neptune
    - PJM-NYISO VFT
    - HQ-NYISO 7040
    - HQ-NYISO Cedars

8.6 Re-Establishing Power Control Center Control

Operation at the ACC shall be maintained until a dispatching crew has arrived at the PCC and is ready to assume control. Once voice communication between PCC and the TOs has been restored, the NYISO Operator on duty at the PCC shall terminate the Major Emergency and notify the TOs that normal PCC operation has resumed. The dispatching staff at the ACC shall deliver all log sheets and pertinent data to the PCC.

9. TESTING EMERGENCY PROCEDURES

This section describes the methods for testing emergency procedures.

9.1 Overview

The NYISO shall test emergency procedures on a regular basis to familiarize Operations personnel with these procedures and to better prepare if an actual emergency occurs.

Testing of emergency procedures is initiated by the NYISO. When testing of emergency procedures is initiated, Transmission Owners are requested to simulate the execution of one of the following emergency procedures:

- Load Shedding
- Voltage Reduction
- NYISO Emergency Restoration
- Interim NYCA and ACC Operation

9.1.1 Frequency of Testing

The NYISO shall initiate tests of emergency procedures periodically, as presented in Table 9.1.

Table 9.1 Frequency of Testing

Test	Frequency
Load Shedding	Twice each Capability Period
Voltage Reduction	Once each Capability Period
NYISO Emergency Restoration	Once a year at the start of the Summer Capability Period
Interim Control Operator (ICO) and Alternate Control Center Operation	Once a year at the start of the Summer Capability Period

If an actual emergency occurs during the Capability Period and one or more of these procedures are actually exercised, then additional testing of that procedure may be omitted during the remainder of the Capability Period.

The NYISO shall maintain a log of the tests conducted during each Capability Period to ensure that the required tests have been completed.

9.1.2 General Testing Procedure

At an appropriate time between 1000 and 1400, the NYISO shall initiate a test of one of the Emergency Procedures. The NYISO shall clearly indicate that it is a test and that a Major Emergency does not exist. The NYISO shall uses the dialog specified on the relevant form(s) provided in Attachment D.

Upon being notified of the test, the TOs shall proceed through the steps that normally are required if an actual order to implement the procedure is given, without actually activating any Voltage Reduction, , Load Shedding devices or any switching for restoration procedures.

Throughout the exercise, the TOs shall note the time each step is exercised and the estimated results. Specific responsibilities for each procedure are identified in each procedure.

The NYISO shall assume the communication responsibilities that they have during an actual system emergency.

When a test is completed, the NYISO shall notify all TOs that the test is terminated.

In the event an actual emergency occurs during a test of emergency procedures, the NYISO shall inform all TOs via the Emergency Hot Line System that the test is canceled and that an actual emergency exists.

9.1.3 Review of Testing

The NYISO Operating Committee reviews and analyzes each test of these emergency procedures with the objective of ensuring that the actual results comply with expected or required objectives and that the emergency procedures can be used promptly and effectively when required. Further, the NYISO Operating Committee reviews the emergency testing procedures annually and revises them, if necessary.

9.2 Test Procedure for Requesting Load Shedding

At an appropriate time between 1000 and 1400, the NYISO shall initiate a test of Load Shedding. The NYISO shall clearly indicate that it is a test and that a Major Emergency does not exist. The NYISO shall use the dialog specified in form D-1, in Attachment D.

Upon being notified of the test, the TOs shall proceed through the steps that normally are required if an actual request to implement Load Shedding is given, without actually activating any Load Shedding devices. The Load Shed Alarm System shall not be activated during a test procedure. In the event an actual emergency occurs during a test and Load Shedding is required, the Load Shed Alarm System shall be activated.

NYISO Actions

The NYISO shall perform the following:

1. Initiate the test.
2. Record TO test data and times on form D-1, Attachment D.

3. Forward the test data and times to the NYISO Chief System Operator.

The NYISO Chief System Operator shall perform the following actions:

1. Review the test data and times with TOs.
2. Issue a report to NYISO Manager of Operations and NYISO Operating Committee Members.

Transmission Owner Actions

The TOs shall perform the following:

1. Initiate the test at TO level.
2. Report the following information to the NYISO:
    - System load at time of order
    - Time Load Shedding completed
    - Estimated amount of MW shed

9.3 Test Procedure for Requesting Voltage Reduction

At an appropriate time between 1000 and 1400, the NYISO shall initiate a test of Voltage Reduction. The NYISO shall clearly indicate that it is a test and that a Major Emergency does not exist. The NYISO shall use the dialog specified in form D-2, Attachment D.

Upon being notified of the test, the TOs shall proceed through the steps that are normally required if an actual request to implement Voltage Reduction is given, without actually activating any Voltage Reduction devices.

NYISO Actions

The NYISO shall perform the following:

1. Initiate the test.
2. Record TO test data and times on form D-2, Attachment D.
3. Forward the test data and times to the NYISO Chief System Operator.

The NYISO Chief System Operator shall perform the following actions:

1. Review the test data and times with TOs.
2. Issue a report to the NYISO Manager of Operations and the NYISO Operating Committee Members.

Transmission Owner Actions

The TOs shall perform the following:

1. Initiate the test at TO level.
2. Report the following information to the NYISO:
    - System load at time of order.
    - Time notifications completed.

- Estimated Load Relief achieved.

9.4 Test Procedure for Requesting Emergency Restoration of NYS Power System

At an appropriate time between 1000 and 1400, the NYISO shall initiate a test of Emergency Restoration. The NYISO shall clearly indicate that it is a test and that a Major Emergency does not exist. The NYISO shall use the dialog specified in form D-4, Attachment D.

Upon being notified of the test, the TOs shall proceed through the steps that are normally required if an actual request to implement Emergency Restoration is given, without actually performing any switching for restoration procedures.

NYISO Actions

The NYISO shall perform the following:

1. Initiate the test.
2. Record TO test data and times on form D-4, Attachment D.
3. Forward the test data and times to the NYISO Chief System Operator.

The NYISO Chief System Operator shall perform the following actions:

1. Review test data and times with TOs.
2. Issue a report to the NYISO Manager of Operations and the NYISO Operating Committee Members.

Transmission Owner Actions

The TOs shall perform the following:

1. Initiate the test at TO level.
2. Report the following information to the NYISO:
    - Estimated time to complete restoration.

9.5 Test Procedure for Interim New York Control Area Operation and ACC Operation

At an appropriate time, between 1000 and 1400, the NYISO shall initiate a test of Interim NYCA Operation and ACC Operation. The NYISO shall clearly indicate that it is a test and that a Major Emergency does not exist. The NYISO shall use the dialog specified in form D-5, Attachment D.

Upon being notified of the test, the TOs shall proceed through the steps that are normally required if an actual order to implement Interim NYCA Operation & ACC Operation is given.

During the test of Interim NYCA Operation & ACC Operation, responsibility for the reliability of the NYS Power System shall be transferred to National Grid and Consolidated

Edison, as the designated NYCA coordinators for the interim period and shall be transferred to the ACC once it is staffed. The NYISO Operations Staff shall maintain shift operation at the PCC and shall monitor system conditions at all times. If conditions indicate that the NYS Power System may be in jeopardy, the NYISO at the PCC shall terminate the test and shall re-assume control of the NYS Power System.

NYISO Actions

The NYISO – PCC shall perform the following:

1. Initiate the test.
2. Continue to monitor system conditions.

The NYISO – ACC shall perform the following actions:

1. Evacuate the NYISO PCC with spare crew of NYISO personnel.
2. Set up the ACC and assume control of the NYS Power System.
3. Record test data and times on form D-5, Attachment D.
4. Forward the test data and times to the NYISO Chief System Operator.

The NYISO Chief System Operator shall perform the following actions:

1. Review the test data and times with TOs.
2. Issue a report to the NYISO Manager of Operations and the NYISO Operating Committee Members.

Transmission Owner Actions

National Grid and *Consolidated Edison* shall perform the following:

1. Assume responsibility for the NYS Power System during the Interim NYCA Operation Period
2. Record test data and times on form D-6, Attachment D.
3. Prepare the logs provided in Attachment E.
4. Forward the test data and times and any logs to the NYISO within 1 week of the test.

All TOs shall perform the following actions:

1. Initiate the test at TO level.
2. Operate in Interim NYCA Operation mode until the ACC is staffed.
3. Report to the NYISO – ACC any problems encountered during the test period. These problems shall also be listed on form D-6, Attachment D.
4. Forward the completed forms and logs to the NYISO within one week of the test.

9.5.1 Review of Interim New York Control Area and Alternate Control Center Operations

The NYISO Operating Committee evaluates each test to ensure the information the ACC collects and disseminates is retained and reviewed. Each transmission owner shall provide a designated observer in its control room during the test. The observer shall monitor the

actual test and shall sign and submit the appropriate report(s) to the NYISO Operating Committee.

Attachment A. Operating Criteria

- Table A.1 lists exceptions to the NYSRC Reliability Rules
- Table A.2 lists bus voltage limits.
- Table A.3 lists pre-contingency low limits for various HQ to NYISO transfers.
- Table A.4 lists multiple circuit tower lines in the New York Control Area.
- Table A.5 lists the NYISO thunderstorm multiple contingencies.
- Table A.6 lists the IROL Interfaces.
- Table A.7 lists the Under Frequency Load Shed (UFLS) Implementation Plan

Note: The above attachments do not require committee approval and are subject to change at the NYISO's direction.

Table A.1 Exceptions to the NYSRC Reliability Rules

The exceptions to the NYSRC Reliability Rules are approved by the NYSRC. The current set of exceptions can be found at:

http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp

Table A.2 Bus Voltage Limits

Bus Name	Target Voltage	Pre Low	Pre High	Post Low	Post High	Set By
Bowline 345	358	345	362	328	362	OR
Buchanan 345	358	346	362	328	380	CE
Clay 345	353	345	362	328	362	NM
Coopers Corners 345	356	338	362	328	380	NY
(4) Dunwoodie 345	358	Table A.3	362	328	380	CE
(1) Edic 345	354	347	362	328	362	NM
Farragut 345	356	338	362	328	380	CE
Fraser 345	356	338	362	328	380	NY
Gardenville 230	236	225	242	207	242	NY
Gilboa 345	356	348	362	328	362	PA
Goethals 345	357	338	362	328	380	CE
Gowanus 345	356	338	362	328	380	CE
Ladentown 345	358	346	362	328	380	CE
Leeds 345	355	345	362	328	372	NM
(1) Marcy 345	355	348	362	328	380	PA
(4) Millwood 345	356	Table A.3	362	328	380	CE
New Scotland 345	355	348	362	328	362	NM
Niagara 230	238	225	242	219	242	PA
Niagara 345	356	338	362	328	362	PA
Northport 138	142	135	145	131	145	LI
(2) Oakdale 345	353	Table A.3	362	320	380	NY
Pannell Road 345	355	344	359	328	362	RG
(4) Pleasant Valley 345	357	Table A.3	362	328	380	CE
Rainey 345	357	338	362	328	380	CE
(3) Ramapo 345	357	346	362	328	380	CE
Ramapo 500	532	500	550	500	575	CE
Rock Tavern 345	357	348	362	328	362	CH
Roseton 345	359	345	362	328	362	CH
Somerset 345	356	338	362	328	380	NY
(4) Sprainbrook 345	358	Table A.3	362	328	380	CE
Station 80 345	355	343	359	328	362	RG
St. Lawrence 230	235	225	242	219	242	PA
Watercure 230	230	215	242	207	242	NY

Notes

(1) Marcy 345 kV bus voltage is reduced to 345 kV prior to energizing the Massena-Marcy 765 kV MSU1 line. By exception, Marcy and Edic voltages are allowed below their pre -contingency low limits for this condition.

(2) Pre-contingency low limits for various configurations of the Fraser SVC are listed in Table A.3.

(3) Voltage below 327 kV at Ramapo may cause the loss of the Bowline Units.

(4) Pre-contingency low limits vary with status of Sprainbrook/Dunwoodie Series Reactors listed in Table A.3.

Table A.3 Bus Voltage Limits for Various Sensitivities

NYS Power System Status	Pre-contingency Low Bus Voltage Limits				
	Oakdale 345 KV	Pleasant Valley 345 kV	Sprainbrook 345 kV	Dunwoodie 345 kV	Millwood 345 kV
Fraser SVC status:					
Fraser SVC In service and 'normal'	336 kV	--	--	--	--
Fraser SVC out of service or ‘not normal’	339 kV	--	--	--	--
Sprainbrook/Dunwoodie Series Reactors					
Series Reactors Bypassed	--	343 kV	346 kV	346 kV	344 kV
Series Reactors Inserted	--	348 kV	348 kV	348 kV	348 kV

Table A.4 Multiple Circuit Tower Lines in New York Control Area

Table A.4 Multiple Circuit Tower Lines in New York Control Area

Circuit Designations	Terminals	Included in CA	Exemption and Reason
345 kV			
11	Oswego-Volney		
17	Oswego-Elbridge-Lafayette	Yes	
91 92	Athens-Pleasant Valley Leeds-Pleasant Valley (2 Parallel Circuits)	No	Note 1
GNS1 GL3	Gilboa-New Scotland Gilboa-Leeds	No	Note 1
F30/W80 F31/W81	Pleasant Valley-Wood St-Millwood W. (2 Parallel Circuits)	Yes	
W82/W65 W85/W78	Millwood W.-Eastview-Sprainbrook (2 Parallel Circuits)	Yes	
F36 F37	Pleasant Valley-E. Fishkill (2 Parallel Circuits)	Yes	
F38/Y86 F39/Y87	E. Fishkill-Wood St-Pleasantville (2 Parallel Circuits)	Yes	
W89 W90	Pleasantville-Dunwoodie (2 Parallel Circuits)	Yes	
W93/W79- W99/W64	Buchanan-Eastview-Sprainbrook Millwood W.-Eastview-Sprainbrook	Yes	
W97 W98	Buchanan S.-Millwood W. (2 Parallel Circuits)	No	Note 2
W72 Y94	Ramapo-Ladentown & Ramapo-Buchanan N.	Yes	
Y88 Y94	Ladentown-Buchanan S. & Ramapo-Buchanan N.	Yes	
67 68	Bowline Pt.-W. Haverstraw Ladentown & Bowline Pt.-Ladentown	Yes	

Table A.4 Multiple Circuit Tower Lines in New York Control Area

Circuit Designations	Terminals	Included in CA	Exemption and Reason
21 22	Goethals-Fresh Kills (2 Parallel Circuits)	Yes	--
69/J3410- 70/K3411	Ramapo-Waldwick (2 Parallel Circuits)	Yes	--
EF24-40 UCC2-41	Edic-Fraser Marcy-Coopers Corners	Yes	--
33 UCC2-41	Fraser-Coopers Corners Marcy-Coopers Corners	Yes	--
CMT-34/CRT-34 CCRT-42	Coopers Corners-Middletown-Rock Tavern Coopers Corners-Rock Tavern	Yes	--
4-46 22	Lafayette-Clarks Corners Dewitt-Lafayette	No	Note 1
11 12	Oswego-Volney (2 Parallel Circuits)	No	Note 1
230 kV & 345 kV			
11 UCC2-41	Chases Lake-Porter (230kV) Marcy-Coopers Corners (345kV)	Yes	--
12 18	Adirondack-Porter (230 kV) Marcy-New Scotland (345 kV)	Yes	--
67 37	Stolle Rd-High Sheldon- (230 kV) Stolle Road-Homer City (345 kV)	Yes	--
31 UCC2-41	Porter-Rotterdam (230 kV) Marcy-Coopers Corners (345 kV)	Yes	--
30 EF24-40	Porter-Rotterdam (230 kV) Edic-Fraser (345 kV)	Yes	--
230 kV			
61 64	Niagara-Packard Niagara-Robinson Road	Yes	--
62 PA27	Niagara-Packard Niagara-Beck	Yes	--
62 BP76	Niagara-Packard Packard-Beck	Yes	--
72 69	Stoney Ridge-Hillside Hillside-Watercure Road	Yes	--
73 74	Gardenville-Dunkirk (2 Parallel Circuits)	Yes	--

Table A.4 Multiple Circuit Tower Lines in New York Control Area

Circuit Designations	Terminals	Included in CA	Exemption and Reason
77 78	Packard-Huntley (2 Parallel Circuits)	Yes	--
77 80	Packard-Huntley Huntley-Gardenville	Yes	--
78 79	Packard-Huntley Huntley-Gardenville	Yes	--
79 80	Huntley-Gardenville (2 Parallel Circuits)	Yes	--
PA27 BP76	Niagara-Beck Packard-Beck	Yes	--
L33P L34P	St. Lawrence T.S.-Moses (2 Parallel Circuits)	Yes	--
MA-1 MA-2	Moses-Adirondack Moses-Adirondack (2 Parallel Circuits)	Yes	--
MMS1 MMS2	Moses-Massena (2 Parallel Circuits)	Yes	--
61 62	Niagara-Packard (2 Parallel Circuits)	No	Note 1
230 kV & 115 kV			
68 160	Dunkirk-S. Ripley (230 kV) Dunkirk-Falconer (115 kV)	Yes	--
61 191	Niagara-Packard (230 kV) Niagara-Packard (115 kV)	Yes	--
MW2 MAL4	Moses-Willis (230kV) Moses-Alcoa N.(115kV)	Yes	--

Note 1: Exempt because of 5 tower criteria.
Note 2: Exempt because they are not adjacent.
Note 3: Exempt by NYISO for development of Voltage limits only.
Note 4: CA refers to Contingency Analysis

Table A.5 List of Thunderstorm Multiple Contingencies Cases

Table A.5 List of Thunderstorm Multiple Contingencies Cases

1. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 311
2. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 77
3. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y94, TA5, Bank (95891)
4. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, Y88
5. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, F31, W81
6. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W82, Eastview Bank 2S, W65
7. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W93, Eastview Bank 2N, W79
8. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, A2253
9. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, W75
10. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 301
11. F38, Y86, F39, Y87, Wood St. Bank 2, Pleasantville Bank 1, 303
12. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 311
13. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 77
14. W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y94, TA5 Bank (95891)
15. W89, W73, W90, W74, Y50, Pleasantville Bank 2, Y88
16. W89, W73, W90, W74, Y50, Pleasantville Bank 2, F31, W81
17. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W82 Eastview Bank 2S, W65
18. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W93, Eastview Bank 2N, W79
19. W89, W73, W90, W74, Y50, Pleasantville Bank 2, A2253
20. W89, W73, W90, W74, Y50, Pleasantville Bank 2, W75, 72, 71
21. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 301
22. W89, W73, W90, W74, Y50, Pleasantville Bank 2, 303
23. F36, F37, 301
24. F36, F37, 303
25. F36, F37, 311
26. F36, F37, 77
27. F36, F37, Y94, TA5 Bank (95891)
28. F36, F37, Y88
29. F36, F37, F31, W81
30. F36, F37, W82, Eastview Bank 2S, W65

Table A.5 List of Thunderstorm Multiple Contingencies Cases

31. F36, F37, W75
32. F36, F37, W93, Eastview Bank 2N, W79
33. F36, F37, A2253
34. F36, F37, F38, RFK305
35. F31, W81, F30, W80, Wood St. Bank 1, 311
36. F31, W81, F30, W80, Wood St. Bank 1, 77
37. F31, W81, F30, W80, Wood St. Bank 1, Y94, TA5 Bank (95891)
38. F31, W81, F30, W80, Wood St. Bank 1, Y88
39. F31, W81, F30, W80, Wood St. Bank 1, W75
40. F31, W81, F30, W80, Wood St. Bank 1, F38, Y86, Pleasantville Bank 1
41. F31, W81, F30, W80, Wood St. Bank 1, W93, Eastview Bank 2N, W79
42. F31, W81, F30, W80, Wood St. Bank 1, A2253
43. F31, W81, F30, W80, Wood St. Bank 1, 301
44. F31, W81, F30, W80, Wood St. Bank 1, 303
45. F31, W81, F30, W80, Wood St. Bank 1, 305
46. W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W99, Eastview Bank 1N, W64, W78
47. W85, W82, W65, Eastview Bank 2S, Eastview Bank 1S, W93, Eastview Bank 2N, W79, W78
48. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y94, TA5 Bank (95891), IP2
49. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Y88
50. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, F38, Y86, Pleasantville Bank 1
51. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, Eastview Bank 1S, W85, W78
52. W99, W64, Eastview Bank 1N, W93, W79, Eastview Bank 2N, W82 Eastview Bank 2S, W65
53. Y88, Y94, TA5 Bank (95891), 91
54. Y88, Y94, TA5 Bank (95891), 92
55. Y88, Y94, TA5 Bank (95891), F38, Y86, Pleasantville Bank 1
56. Y88, Y94, TA5 Bank (95891), F39, Y87, Pleasantville Bank 2, Wood St. Bank 2
57. Y88, Y94, TA5 Bank (95891), F31, W81
58. Y88, Y94, TA5 Bank (95891), F30, Wood St. Bank 1, W80
59. Y88, Y94, TA5 Bank (95891), W93, Eastview Bank 2N, W79, IP2
60. Y88, Y94, TA5 Bank (95891), A2253
61. Y88, Y94, TA5 Bank (95891), 301
62. Y88, Y94, TA5 Bank (95891), 303

Table A.5 List of Thunderstorm Multiple Contingencies Cases

63. Y88, Y94, TA5 Bank (95891), RFK305

64. W97, W98, Y88, IP3

65. W97, W98, Y88, IP3, 91

66. W97, W98, Y88, IP3, 92

67. W97, W98, Y88, IP3, F38, Y86, Pleasantville Bank 1

68. W97, W98, Y88, IP3, F39, Y87, Wood St. Bank 2

69. W97, W98, Y88, IP3, F31, W81

70. W97, W98, Y88, IP3, F30, Wood St. Bank 1, W80

71. W97, W98, Y88, IP3, W93, Eastview Bank 2N, W79

72. W97, W98, Y88, IP3, 301

73. W97, W98, Y88, IP3, 303

74. W97, W98, Y88, IP3, RFK305

75. 91, 92

76. 91, 311

77. 91, 77

78. 92, 311

79. 92, 77

80. 91, 301

81. 91, 303

82. 91, RFK305

83. 301, RFK305

84. 69, South Mahwah Bank, J3410, Waldwick Bank 2, 70, K3411, Waldwick Bank 3, Y88

85. Y88, Y94, TA5 (95891), 69, South Mahwah Bank, J3410, Waldwick Bank 2

86. Y88, Y94, TA5 (95891), 70, K3411, Waldwick Bank 3

Table A.6 IROL Interfaces

IROL Stability	Post Contingency Voltage IROL
IESO-NYISO	Central East-VC
ISONE-NYISO	Central East loss of NE Generation
PJM-NYISO	
Western Export	
Dysinger	
Oswego Export	
Moses-South	
Central East	
Total East	
UPNY-Con Ed	

Table A.7 Under Frequency Load Shed (UFLS) Implementation Plan

Implementation Date	Conversions/ Modifications	Original Remaining	Total	Remarks
Prior June 26, 2010			10% - 59.3 Hz 15% - 58.8 Hz	
June 26, 2010	7% of the 10% block to 59.5 Hz.	3% - 59.3 Hz 15% - 58.8 Hz	7% - 59.5 Hz 3% - 59.3 Hz 15% - 58.8 Hz	Setting changes only. Total clearing time of 300 ms can be implemented if possible.
June 26, 2011	4% of the 15% block to 59.3 Hz. 3% of the 15% block to 59.1 Hz.	3% - 59.3 Hz 8% - 58.8 Hz	7% - 59.5 Hz 7% - 59.3 Hz 3% - 59.1 Hz 8% - 58.8 Hz	Setting changes only. Leave original 3% at 59.3 Hz. Total clearing time of 0.3 seconds can be implemented if possible.
June 26, 2012	4% of the 15% block to 59.1 Hz. 3% of the 15% block to 58.9 Hz. Add UFLS capacity of 2% at 58.9 Hz with total time delay of 0.3 sec.	3% - 59.3 Hz 1% - 58.8 Hz	7% - 59.5 Hz 7% - 59.3 Hz 7% - 59.1 Hz 3% - 58.9 Hz 2% - 58.9 Hz (fast) 1% - 58.8 Hz	1st year of adding 2% portion of the new UFLS capacity. New capacity will have total clearing time of 300 ms. 1st year of decreasing total time if not already done so. Clearing time changes must be implemented if not done already in year 1 and 2.
June 26, 2013	1% of the 15% block to 58.9 Hz Change time of 1st block (59.5 Hz) to total of 0.3 sec. Add UFLS capacity of 1% at 58.9 Hz with total time delay of 0.3 sec. Add UFLS capacity of 2% Anti-stall block at 59.5 Hz with total time delay of 10 sec.		7% - 59.5 Hz (fast) 7% - 59.3 Hz 7% - 59.1 Hz 3% - 58.9 Hz 4% - 58.9 Hz (fast) 2% - 59.5 Hz (10 s)	Adding anti-stall block.
June 26, 2014	Change time of 2nd block (59.3 Hz) to total of 0.3 sec.		7% - 59.5 Hz (fast) 7% - 59.3 Hz (fast) 7% - 59.1 Hz 3% - 58.9 Hz	Continue with time delay changes.

			4% - 58.9 Hz (fast) 2% - 59.5 Hz (10 s)	
June 26, 2015	Change time of 3rd block (59.1Hz) to total of 0.3 sec. Change time of remaining 4th block (58.9 Hz) to total of 0.3 sec .		7% - 59.5 Hz (fast) 7% - 59.3 Hz (fast) 7% - 59.1 Hz (fast) 7% - 58.9 Hz (fast) 2% - 59.5 Hz (10 s)	Program complete.

1 All percentages are approximate.

2. Conversions and modifications are to be dispersed geographically throughout an Area, as much as practical.

3. All conversions include the modifications necessary to achieve a total clearing time (UFLS relay operating time, aux relay time, and breaker time) of 300 ms. The 300 ms total clearing time can be taken as an average value. The regional standard could be written to require an average total clearing time plus or minus some standard deviation, such as 50 ms.

4. A minimum UFLS relay operating time shall not be less than 100 ms.

Attachment B. Restoration Procedures and Diagrams

B-1 NYISO Restoration Guidelines

B-2 NYISO Restoration Procedure - which defines the sequence of switching steps used in the event of a complete NYS Power System shutdown, and provides a form for recording execution or simulation of the switching steps.

B-3 NYISO Restoration Diagram

B-4 NYISO Black Start Facilities Table

B-5 NYISO Line Charging Table

B-6 NYISO Inter-Area Restoration Coordination Table

B-7 NYISO Key Facility List

B-8 NYISO Emergency Operations Manual Annual Review Record

Note: Due to the Critical Energy Infrastructure Information (CEII) classification of this information it is not public. In addition, the above attachments do not require committee approval and are subject to change at the NYISO's direction.

Attachment C. Load Relief Capability

- Table C.1 tabulates the Load Relief available from Voltage Reduction and load curtailment.
- Table C.2 allocates New York Control Area wide load reduction among the Transmission Owners (TOs).
- Table C.3 allocates load reduction among the TOs on a geographic basis.

Note: The above attachments do not require committee approval and are subject to change at the NYISO's direction.

Table C.1 Summer 2015 Load Relief Measures

VOLTAGE REDUCTION CAPABILITY PERIOD SUMMER 2015

Remote TO--->	LI			CE			OR			CH			PA			NG			NY			RG			TOTAL (NYISO)		
ZONE	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%	3%	5%	8%
A																	27	27							0	27	27
B																	12	12				6	11	18	6	23	30
C																	18	18		6	6				0	24	24
D																	7	7							0	7	7
E																	11	11							0	11	11
F																	11	11							0	11	11
G								8	8		7	7													0	15	15
H					3	5																			0	3	5
I					28	45																			0	28	45
J					202	323																			0	202	323
K	19	25	25																						19	25	25
TOTAL (TO	19	25	25	0	233	373	0	8	8	0	7	7	0	0	0	0	86	86	0	6	6	6	11	18	25	376	523

MANUAL TO--->	LI		CE			OR		CH		PA		NG		NY		RG		TOTAL (NYISO)		
ZONE	3%	5%	3%	5%	8%	3%	5%	3%	5%	3%	5%	3%	5%	3%	5%	3%	5%	3%	5%	8%
A										2	4				6			2	10	0
B										3	6						5	3	11	0
C										4	7				8			4	15	0
D										6	10				1			6	11	0
E										3	5				4			3	9	0
F															1			0	1	0
G									6									0	6	0
H															3			0	3	0
I																		0	0	0
J																		0	0	0
K										0	0							0	0	0
TOTAL(TO	0	0	0	0	0	0	0	0	6	18	31	0	0	0	23	0	5	18	65	0

SUMMER 2015

LOAD RELIEF MEASURES

Transmission Owner: Total NYISO

	Mkt. Participant Non-Essential Use			TO Interruptible Customers			Voluntary Large Indus. & Commrcl.			Public Appeal			Total Curtailments
Zone	W	C	E	W	C	E	W	C	E	W	C	E	
A	0.10												0.10
B	4.00						1.00			8.00			13.00
C		0.40											0.40
D													0.00
E		0.20											0.20
F			0.10										0.10
G			5.25						8.20				13.45
H						0.11							0.11
I						2.48			0.15				2.63
J						86.80			3.90				90.70
K						29.00						80.00	109.00
TOTAL TO	4.10	0.60	5.35	0.00	0.00	118.39	1.00	0.00	12.25	8.00	0.00	80.00	229.69
TOTAL NYCA	10.05			118.39			13.25			88.00			229.69

NOTES:

W	West
C	Central
E	East

Table C.2 Load Reduction by NYISO (in Megawatts)

REDUCTION REQUIRED	CH	CE	LI	NYSEG	NG	O&R	RGE	TOTAL
100	4	41	16	12	20	3	5	100
200	7	82	32	23	40	7	9	200
300	11	123	47	35	60	10	14	300
400	14	164	63	47	80	14	19	400
500	18	205	79	58	100	17	23	500
600	21	246	95	70	120	21	28	600
700	25	287	110	82	140	24	32	700
800	28	328	126	93	160	27	37	800
900	32	369	142	105	180	31	42	900
1000	35	410	158	117	200	34	46	1000

Table C.3 Allocation of Load Reduction among All Members in a Geographic Area (In Megawatts)

Load Reduction to Relieve West-Central Transmission

REDUCTION REQUIRED	CH	CE	LI	O&R	NG(C+E)	NYSEG(C+E)	TOTAL
100	4	48	19	4	16	9	100
200	8	97	37	8	32	18	200
300	12	145	56	12	47	27	300
400	17	193	74	16	63	36	400
500	21	242	93	20	79	45	500
600	25	290	112	24	95	55	600
700	29	338	130	28	111	64	700
800	33	386	149	32	126	73	800
900	37	435	167	36	142	82	900
1000	42	483	186	40	158	91	1000

Load Reduction to Relieve Central-East Transmission

REDUCTION REQUIRED	CH	CE	LI	O&RU	NG(E)	NYSEG(E)	TOTAL
100	5	57	22	5	9	3	100
200	10	114	44	9	17	6	200
300	15	171	66	14	26	9	300
400	20	228	88	19	35	12	400
500	24	284	110	24	43	15	500
600	29	341	131	28	52	18	600
700	34	398	153	33	60	21	700
800	39	455	175	38	69	24	800
900	44	512	197	43	78	27	900
1000	49	569	219	47	86	29	1000

Load Reduction to Relieve UPNY-CONED Transmission

REDUCTION REQUIRED	CE	LI	NYSEG(E)	TOTAL
100	62	36	2	100
200	124	72	4	200
300	186	108	6	300
400	248	144	8	400
500	310	180	10	500
600	372	216	12	600
700	434	252	14	700
800	496	288	16	800
900	558	324	18	900
1000	620	360	20	1000

Attachment D. Emergency Procedure Testing Forms

- D-1 defines standard terminology used in conducting tests of the Load Shedding procedure and provides a form for recording test results.
- D-2 defines standard terminology used in conducting tests of the Voltage Reduction procedure and provides a form for recording test results.
- D-4 defines standard terminology used in conducting tests of the Restoration procedure and provides a form for recording test results.
- D-5 defines standard terminology used in conducting tests of the Interim New York Control Area Operation & Alternate Control Center Operation procedures and provides a form for recording test results.
- D-6 defines standard terminology used in conducting tests of the Interim New York Control Area Operation & Alternate Control Center Operation TO Data Submittal procedures and provides a form for recording test results.

Note: The above attachments do not require committee approval and are subject to change at the NYISO's direction.

D-1 Test of Load Shedding Procedure

The NYISO Shift Supervisor shall make the following statements:

- "This is a test of the load shedding procedure. DO NOT shed any actual load."
- "Report back to me your load at the time of the load shed order, and the time that the test of the load shedding procedure is complete."
- "Confirm that this is only a test to simulate Load Shed by TO."
- "This is a test of the load shedding procedure. DO NOT shed any actual load."

Note: Do not activate the Load Shed Alarm System during test procedure.

Table D.1 Test of Load Shedding Procedure Form

Test initiated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

Transmission Owner	Load Shed Order (MW)	Time of Order	Load at Time of Order (MW)	Time of Completion	Estimated Load Relief (MW)
CE					
LI					
OR					
CH					
NG					
NY					
RG					

Test terminated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

D-2: Test of Voltage Reduction Procedure

The NYISO Shift Supervisor shall make the following statements:

- "This is a test of the voltage reduction procedure. DO NOT actually initiate voltage reduction."
- "Report back to me your load at the time of the voltage reduction order, and the time that the test of the voltage reduction procedure is complete."
- "Confirm that this is only a test to simulate the Voltage Reduction Procedure."
- "This is a test of the voltage reduction procedure. DO NOT actually initiate voltage reduction."

Table D.2 Test of Voltage Reduction Procedure Form

Test initiated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

Transmission Owner	Voltage Reduction %	Manual or Quick Response	Time of Order	Time of Completion	Estimated Load Relief (MW)
CE					
LI					
OR					
CH					
NG					
NY					
RG					
PA					

Test terminated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

Table D.3 Test of Restoration

Refer to the Restoration Procedures in the *NYISO System Restoration Manual* (available from the http://www.nyiso.com/public/documents/manuals/operations.jsp?maxDisplay=20).

D-5: Test of Interim New York Control Area Operation Procedure & Alternate Control Center Operation

The NYISO Shift Supervisor shall make the following statement:

> "This is a test of the Interim NYCA Operation Procedure & Alternate Control Center Operation. At this time, a simulated evacuation of the NYISO Power Control Center will begin. National Grid and Con Edison shall assume control of the NYS Power System under the conditions described in section 9 of this Manual until communication is established from the Alternate Control Center."

Table D.4 Test of Interim New York Control Area Operation Procedure & Alternate Control Center Operation Form

Test initiated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

SSO-ACC _____
Name

SO-Generation-ACC _____
Name

SO-Transmission-ACC _____
Name

Time of Arrival at ACC _____
Time and Date

Communication Established _____
Time and Date

Transmission Owner Directed Dispatch Begun _____
Time and Date

Problems Encountered:

_____

_____

_____

_____

_____

Test terminated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

Completed by: _____
(Company/Operator)

D-6: Test of Interim New York Control Area Operation Procedure & Alternate Control Center Operation Transmission Owner Data Submittal

Table D.5 Test of Interim New York Control Area Operation Procedure & Alternate Control Center Operation Transmission Owner Data Submittal Form

Test initiation message received at _____
(Time and Date)

Message received from _____ of _____
(Dispatcher) (NYISO or DIC)

Section to be completed by Designated NYISO Coordinator (DIC):

Communication Established with NG/CE _____
(Time and Date)

Communication Established with External Systems _____
(Time and Date)

Communication Established with Internal Systems _____
(Time and Date)

First Reserve Check Completed _____
(Time and Date)

Transmission Owner Directed Dispatch Begun _____
(Time and Date)

Section to be Completed by ALL other System Operators:

Communication Established with Designated NYISO Coordinator _____
(Time and Date)

Communication Established with ACC _____
(Time and Date)

Transmission Owner Directed Dispatch Begun _____
(Time and Date)

Problems Encountered:

_____
_____
_____
_____
_____

Test terminated at _____ by _____
(Time and Date) (NYISO Shift Supervisor)

NYISO Operating Committee Observer _____

Company: _____

Attachment E. Data Collection Forms

- Table E.2: DNI Change Log
- Table E.2: Reserve Allocation Survey UPNY
- Table E.3: Reserve Allocation Survey SENY

> ***Note:*** The above attachments do not require committee approval and are subject to change at the NYISO's direction.

The following data shall be collected during Interim New York Control Area Operation by the Designated NYISO Coordinator(s), National Grid, and Consolidated Edison.

Transfers

- Moses – South
- Dysinger
- West – Central
- Central – East
- Total – East
- Dunwoodie South
- IESO – NY
- PJM – NY
- ISO – NE – NY
- Each Transmission Owner System Net Interchange

Voltages

- Station 80 345 kV
- Edic 345 kV
- New Scotland 345 kV
- Pleasant Valley 345 kV
- Ramapo 345 kV
- Oakdale 345 kV
- Oakdale 230 kV
- Coopers Corners 345 kV

Other

- Total Ten-Minute Reserve
- Total Operating Reserve

The following forms shall be used for recording Desired Net Interchange (DNI) changes and reserve allocations:

- DNI Change Log - External Proxy
- DNI Change Log – UPNY
- DNI Change Log – SENY

- Reserve Allocation Survey – UPNY
- Reserve Allocation Survey – SENY

Table E.1 DNI Change Log External Proxy

E-1: DNI Change Log - External Proxy

Note: Use the NYISO Sign Convention
Out is Minus (-), In is Plus (+)

DNI CHANGE LOG EXTERNAL PROXY

DATE: _____

		External Proxy Bus DNI												
		UPNY					SENY							
		ONT		HQ			PJM				NE			
Time	Reason for Change	ONT-NY AC	Total ONT	HQ-NY 7040	HQ-Cedars	Total HQ	PJM-NY AC	PJM-NEPTUNE	PJM-VFT	Total PJM	NE-NY AC	1385	CSC	Total NE
	INITIAL DATA													

Table E.2 DNI Change Log UPNY

E-2: DNI Change Log - UPNY

Note: Use the NYISO Sign Convention
Out is Minus (-), In is Plus (+)

DNI CHANGE LOG UPNY

DATE: _____

		EXTERNALS					DNI						
		UPNY		SENY		TOTAL	UPNY DNI				TOTALS		
TIME	REASON FOR CHANGE	IESO	HQ	ISONE	PJM	TOTAL EXT	NG	NYPA	NYS	RGE	TOTAL UPNY	TOTAL SENY	NY DNI
	INITIAL DATA												

Table E.3 DNI Change Log SENY

E-3: DNI Change Log - SENY

Note: Use the NYISO Sign Convention
Out is Minus (-), In is Plus (+)

DNI CHANGE LOG UPNY

DATE: _____

		EXTERNALS					DNI						
		UPNY		SENY		TOTAL	SENY DNI				TOTALS		
TIME	REASON FOR CHANGE	IESO	HQ	ISONE	PJM	TOTAL EXT	CE	LI	CH	OR	TOTAL UPNY	TOTAL SENY	NY DNI
	INITIAL DATA												

Table E.4 Reserve Allocation Survey UPNY

NOTE: Total operating reserve = 10 minute reserve + 30 minute reserve					Reserve Allocation Survey UPNY				Date:_____		
Time	Category	NG	NYS	RGE	NYPA	Total UPNY	Total SENY	Total Recallable Exports	Total NYCA Reserve	Reserve Req	Surplus/ Deficit
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										

Table E.5 Reserve Allocation Survey SENY

NOTE: Total operating reserve = 10 minute reserve + 30 minute reserve					Reserve Allocation Survey SENY				Date:_____		
Time	Category	CE	LI	OR	CH	Total SENY	Total UPNY	Total Recallable Exports	Total NYCA Reserve	Reserve Req	Surplus/ Deficit
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										
	10 Minute										
	Operating										

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Attachment F. Reserve Data

- F-3 is a form for recording actual reserve pickup test results under BDS.
- F-4 is a form for recording actual reserve pickup test results under NYISO Directed Economic Dispatch

Note: The above attachments do not require committee approval and are subject to change at the NYISO's direction.

F-3: Actual Reserve Pickup Test Manual Dispatch System

System _____ Date _____

Ten Minute Reserve Obligation:

Min. Sync. Req. (Exhibit F-1) _____

Max. Non-Sync. Req. (Exhibit F-1) _____

Plus interruptible Purchases from 10-Minute Reserve _____

Minus interruptible Sales from 10-Minute Reserve _____

Net 10-Minute Reserve Obligation _____

System Generation Level Time

At Start of Pickup Started _____

At End of Pickup Terminated _____

Total Gen. Pickup Elapsed Time _____

Comments/Actions Taken

_____

_____

_____

_____

Checked Data with Transmission Owner Agreed _____

Disagreed _____

NYISO Shift Supervisor _____

Transmission Owner Operator _____

F-4: Actual Reserve Pickup NYISO Dispatch System

Unit Lost _____ Output _____ MW Date _____ Time _____

Reserve Pickup Dispatch Initiated at _____

Transmission Owner Systems Notified Via
Emergency Hot Line _____

Reserve Pickup Summary - TOTAL								
	CE	**LI**	**NG**	**NYSEG**	**CH**	**O&R**	**RGE**	**NYCA**
Required								
Actual*								
Satisfied Requirement								
Deficient								

Comments/Actions Taken _____

Checked Data with Deficient Transmission Owner(s) _____

Transmission Owner Operator								
Agreed								
Disagreed								

NYISO Shift Supervisor _____

*Actual pickup measured 10 minutes after Emergency Hot Line message.

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Attachment G. Notification Form

Table G.1, PSC Notification Form

Table G.2, Reporting to the Department of Energy

Note: The above attachments do not require committee approval and are subject to change at the NYISO's direction.

The following standard terminology shall be used when reporting the declaration of Major Emergency to the NYS PSC.

Table G.1 PSC Notification Form

At _____ **on** _____
(Time) (Day, Date)

a Major Emergency was declared by the NYISO Shift Supervisor _____
Initials

Due To:
(Circle the item number for one or more of the following items and complete the requested information)

1. Power flow on line _____ exceeded its (LTE Rating/Stability Limit).

2. Voltage at the _____ bus was (less than/greater than) _____ kV.

3. System frequency was less than _____ Hz.

4. Area Control Error exceeded 500 MW for more than 10 minutes.

5. Separation of the NYISO system has occurred at _____

6. NYISO had to go into Voltage Reduction to provide assistance to _____
(CONTROL AREA)

7. Monitoring equipment was unavailable and the system was thought to be in jeopardy.

The Major Emergency was terminated at _____
(TIME)

Load Relief measures (were / were not) required.
Brief statement of apparent cause (if known). _____

Corrective Action Taken: _____

Table G.2 Reporting to the DOE 417

The OE-417 Electric Emergency Incident and Disturbance Report is accessed via the following link: https://www.oe.netl.doe.gov/OE417/

NEW YORK INDEPENDENT SYSTEM OPERATOR

MANUAL 12

Transmission and Dispatching Operations Manual

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Revision History

Version	Date	Revisions
2.5	**10/30/2015**	**Global** ➢ Removal of "Non-firm transaction" language **Section 3.3** ➢ New section detailing Fuel Availability Self Reporting (FASR) requirements **Section 4.2.8** ➢ Removed. 'Procedure for Relief of Potential Overloads on Non-Secured Facilities' section currently located in the Emergency Operations Manual section 4.1.3. **Section 5.7.5** ➢ New section. Incorporated sections of TB-029 which details generator DMNC test scheduling requirements **Attachment B** ➢ Link to Table B1 and B4 updated **Attachment C** ➢ Removed.
2.4	**12/01/2014**	**Global** ➢ Updated links from individual manuals to the NYISO Manuals webpage **Section 5.1.1** ➢ Incorporated CTS bids into types of external transaction bids ➢ Revisions to reflect scheduling 15-minute external transactions from the first timestep of RTC ➢ Revisions to external proxy bus pricing used for settlement **Figure 5.1** ➢ Revisions to reflect scheduling 15-minute external transactions from the first timestep of RTC **Section 5.1.3** ➢ Updated to remove information no longer posted by RTC **Table 5.1** ➢ Revised terms to be inclusive of CTS bids as necessary **Section 5.2.4** ➢ Clarifications to distinguish CTS bids from other types of external transaction bids ➢ Added description of process for creating CTS bid from accepted DAM transactions **Section 6.3.5** ➢ Update the reference to the 5018 transmission line from "Branchburg-Ramapo Interconnection" to "Hopatcong-Ramapo Interconnection"
2.3	**10/23/2012**	**Section 2.1** ➢ Updated link to NYISO Agreement, NYISO/TO Agreement, and

		NYSRC Agreement **Section 3.1.4** ➢ Updated link to NYISO Ancillary Services Manual ➢ Added link to NYCA regulation requirements **Section 3.1.11** ➢ Updated link to Accounting and Billing Manual **Section 5.1.1** ➢ Updated link to Ancillary Services Manual **Section 5.1.3** ➢ Revised to reflect posting of both a Regulation Capacity and a Regulation Movement price ➢ Clarify that RTC prices are posted separately from RTD prices **Section 5.2.4** ➢ Corrected formatting error **Section 6.1.1** ➢ Clarified that Real-Time Market Prices are calculated for Regulation Service to maintain consistency with Tariff **Section 6.1.2** ➢ Revised to reflect posting of both a Regulation Capacity and a Regulation Movement price ➢ Remove reference to RTD 15-minute look ahead price postings **Section 6.2.1/6.2.2** ➢ Clarified that Regulation schedules are set to zero during Reserve Pickup and Max Gen Pickups **Section 6.3.5** ➢ Revised interchange modeling assumptions to match revisions to TB 152 **Section 6.3.10** ➢ Revised reference to NPCC document describing SAR procedure
2.2	**02/1/2012**	**Global** ➢ Reformatted per new template to standardize presentation. ➢ Implemented minor stylistic changes. ➢ Standardized labeling and numbering of tabular material. ➢ Revised external-document links to explicitly cite URLs from which documents may be accessed. **Table of Tables** ➢ Expanded to include tables in attachments. **Revision History Table** ➢ Changed column headings as follows: • “Revision” changed to “Version” • “Changes” changed to “Revisions” **Section 2.1.5 and 2.1.6** ➢ Switched the order of 2.1.5 and 2.1.6 to better depict the hierarchical relationship between all of the NYS Reliability Rules and the subset of Reliability Rules known as Local Reliability Rules. ➢ Added material on the evolution and implementation of reliability rules

		and the NYISO's responsibilities with regard to reliability rules (incorporated Technical Bulletin #159). ➢ Clarified via a new heading that the process outlined for defining new applications of reliability rules or modifying existing applications of the reliability rules applied to changing the TO application of such rules. **Section 2.2.5** ➢ Added material detailing the conditions under which LESRs will participate in reserve pickups. **Section 2.4** ➢ Modified the Real-time market timelines to reflect 15-minute scheduling and the elimination of pre-scheduling. **Section 4.1.3** ➢ Clarified treatment of Firm Transmission Service for Imports and Exports. **Section 4.2.7** ➢ Clarified that any of the steps outlines may be taken in to relieve the security violation. **Section 4.2.12** ➢ Added new subsection on Status of Transmission and Generation Protection Systems-incorporated TB 167 **Section 5.1.1** ➢ Clarified that RTC15 schedules hourly transactions and that all RTC runs establish schedules for 15-minute transactions. ➢ Added new material on initialization status, startup time, minimum run time, and minimum down time with regard to the Real-Time Commitment process. ➢ Clarified the timeframe during which customers may submit Real-Time Bids into RTC for real-time evaluation. ➢ Added new material detailing the need for internal bilateral transactions involving trading hubs to be balanced and defining the meaning of *balanced* in this context. Incorporated TBs 18, 51,145 **Section 5.1.2** ➢ Removed reference to second impact test. **Section 5.2.3** ➢ Clarified treatment of Firm Bilaterals to align with strategic tariff review updates. **Section 5.2.4** ➢ Incorporated TB #40 **Section 6.2** ➢ Added material specifying LESR response in relation to corrective action during Real-Time Dispatch. **Section 6.3** ➢ Added real-time telemetry of energy storage levels for LESRs to the list of the initial conditions that RTC/RTD determines in beginning the commitment and dispatch process. **Section 6.3.6** ➢ Added a footnote to Table 6.1 stating that If the Regulation Demand Curve is active, RTD will not set basepoints for LESR energy management. **Attachment A**

		➢ Table A.1, A.2, and A.3 - replaced with links to the external locations where each table is maintained. **Attachment B** ➢ Table B.1, B.2, B.3, B.4, and B.5 - replaced with links to the external locations where each table is maintained.
2.1	**09/04/2008**	**Updated Table B-1 to reflect Exceptions to the NYSRC Reliability Rules**
2.0	**11/21/2007**	**Complete manual rewrite.**
1.0	**09/01/1999**	**Initial Release**

1. INTRODUCTION

The *NYISO Transmission & Dispatching Operations Manual* is one of a series of manuals within the Operations Manuals. This Manual focuses on describing each of the Transmission & Dispatching Operations with respect to the New York Independent System Operator (NYISO) facilitates and/or controls.

This Manual consists of five sections as follows:

1. Section 1: Introduction
2. Section 2: Overview
3. Section 3: Operations Monitoring
4. Section 4: Transmission Operations
5. Section 5: Scheduling Operations
6. Section 6: Dispatching Operations

1.1 References

The references to other documents that provide background or additional detail directly related to the *NYISO Transmission & Dispatching Operations Manual* are:

- NYISO Emergency Operations Manual
- NYISO Accounting and Billing Manual
- NYISO Day-Ahead Scheduling Manual
- NYISO Ancillary Services Manual
- NYISO Tariffs
- New York State Reliability Council (NYSRC) Agreement
- NYSRC – Reliability Rules Manual
- Market Participant User's Guide

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2. OVERVIEW

This section presents an overview of the following:

- Operating Policy
- NYISO versus Transmission Owner Responsibilities and Authorities
- Normal and Warning Operating States
- Market Operations Time Line
- Operations Functions
- Communications

2.1 Operating Policy

Under the authority granted by the Federal Energy Regulatory Commission and the terms of the NYISO Agreement, the NYISO/Transmission Owner Agreement, and the NYSRC Agreement (all of which are available from the NYISO Web site at http://www.nyiso.com/public/markets_operations/documents/legal_regulatory/index.jsp), the NYISO has the authority to direct the operation of the New York State Power System (NYS Power System) to maintain system reliability in accordance with good utility practice and the Reliability Rules. The goal is to anticipate potential problems, apply preventative measures, and to respond quickly to actual problems when they occur.

To meet its obligations under the Reliability Rules with respect to maintaining the security of the NYS Power System, the NYISO shall maintain a list of transmission facilities included within the NYS Transmission System, defined as the NYISO Secured Transmission System. The NYISO is responsible for the following:

- The coordination of the operation of those facilities under its Operational Control with the responsible Transmission Owners (TO)
- The commitment and/or dispatch of supply and demand resources connected to the NYS Transmission system, and/or
- The control and/or coordination of facilities used to provide ancillary services
  - Transmission facilities that are under NYISO operational control and require NYISO notification are listed in Attachment A.1 of this Manual.
  - Transmission facilities that require NYISO notification are listed in Attachment A.1 of this Manual.
  - Bus Voltage Limits for buses included as part of the NYISO Secured Transmission System are listed in Attachment A.2 and Attachment A.3 of this Manual.

2.1.1 Operating States

The following five operating states are defined for the NYS Power System:

1. Normal
2. Warning

3. Alert
4. Major Emergency
5. Restoration

The NYISO Shift Supervisor shall determine the state of the NYISO Secured Transmission System by comparing system conditions against certain monitoring criteria. The NYISO Shift Supervisor shall also monitor weather conditions and forecasts.

1. When the NYISO Shift Supervisor determines the state of the NYISO Secured Transmission System is Normal or Warning, the NYISO shall operate the NYS Power System according to the procedures described in this Manual.
2. When the NYISO Shift Supervisor determines the state of the NYISO Secured Transmission System is Alert, Major Emergency, or Restoration, the NYISO shall operate the NYS Power System according to procedures in the *NYISO Emergency Operations Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

2.1.2 NYISO Objective

It is the objective of the NYISO to operate the NYISO Secured Transmission System within the Normal State. Conditions may cause the NYISO Secured Transmission System to depart from the Normal State. Such conditions include, but are not limited to, the following:

1. Capacity deficiencies
2. Energy deficiencies
3. Loss of generation or transmission facilities
4. High voltage
5. Low voltage
6. Environmental episodes
7. Transmission overloads
8. Abnormal power system frequency

When the NYISO Secured Transmission System enters a condition other than the Normal State, the NYISO shall act to return the NYISO Secured Transmission System to the Normal State. When the criteria for the Normal State cannot be achieved, the NYISO shall satisfy as many of the Normal State criteria as possible, and shall minimize the consequences of any single contingency. Should a disturbance occur, the NYISO shall minimize its extent and duration.

When multiple violations occur within the same state, actual violations shall be corrected before predicted violations. Where multiple violations of differing state criteria occur, the most serious violation shall be solved first.

2.1.3 Emergency Conditions

The NYISO Schedule Coordinator, the NYISO Shift Supervisor, or both shall forecast the likelihood of the occurrence of states other than the Normal State as far in advance as possible. If it is predicted that Load Relief, either by Voltage Reduction or Load Shedding, may be necessary during a future period, the NYISO Shift Supervisor shall notify all TOs.

For a detailed description of the procedures to be followed under these conditions, refer to the *NYISO Emergency Operations Manual* (available from the NYISO Web site at http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

Transmission Owners shall develop the necessary communication policies with Transmission Customers. The specific operating methods used by each TO are not necessarily identical. The NYISO Shift Supervisor shall coordinate such methods to achieve uniform results.

2.1.4 General Reliability Rules

The New York State Reliability Council (NYSRC) has the responsibility to develop, establish, maintain, assure compliance with, and, from time-to-time, update the Reliability Rules, which must be complied with by the NYISO and all entities engaging in electric power transactions on the NYS Power System. The NYSRC relies upon the reliability standards, regulations, criteria, procedures, and rules established or imposed by:

- North American Electric Reliability Corporation (NERC),
- Northeast Power Coordinating Council (NPCC),
- Federal Energy Regulatory Commission (FERC),
- New York State Public Service Commission (PSC),
- Nuclear Regulatory Commission (NRC), and/or
- Any other government agency with jurisdiction over the reliability of the NYS Power System.

The NYISO, a Market Participant, or a member of the NYSRC Executive Committee may petition the NYSRC Executive Committee to seek specific and limited exceptions to NERC and NPCC criteria, provided the intent of the criteria is not compromised. The NYSRC will incorporate all new mandatory compliance rules of NERC and NPCC, unless existing Reliability Rules are more stringent.

2.1.5 Applications of the Reliability Rules

Prior to the NYISO startup, the Applications of the Reliability Rules (Applications) were existing operating procedures and local rules implemented by the Transmission Owners in New York. The Applications of the NYSRC Reliability Rules were assembled from these procedures and acknowledged by the NYSRC. The Applications are implemented through procedures that apply to very specific system locations or conditions in New York.

As a threshold matter, please note that the NYISO's tariffs implement certain Reliability Rules directly. The implementation of the Applications of the Reliability Rules will continue to require close coordination between the transmission owners and the NYISO in

order to maintain the reliability of the NYS Power System. The Transmission Owners (TO) must continue to coordinate with the NYISO on the implementation of Applications of the Reliability Rules for those portions of the New York State Transmission System ("NYS Transmission System") not included in the NYISO secured transmission system.

The NYISO oversees compliance with the Reliability Rules for the New York State Power System. The NYISO performs periodic compliance reviews to determine whether the TOs are continuing to apply the Applications to a specific local area. The Annual NYSRC Compliance Program determines the frequency and schedule for the compliance reviews.

Transmission Owner Responsibilities

The TOs are responsible for implementing the Applications of the Reliability Rules for those portions of the NYS Power System that are not included in the NYISO Secured Transmission System. Implementation of certain Applications of the Reliability Rules must be coordinated with the NYISO where the NYISO lacks the necessary analysis and/or monitoring capabilities.

The TOs shall maintain procedures to implement the Applications. Any new or revised procedure developed or modified by the TO shall be provided to the NYISO Staff for review and approval.

A Transmission Owner may define new or modified Applications of the Reliability Rules. New or modified Applications of the NYSRC Reliability Rules, proposed by a Transmission Owner are subject to review and approval by the NYISO Staff.

NYISO Responsibilities

The NYISO shall maintain the Applications of NYSRC Reliability Rules and make them in a table posted on the NYISO's website. The NYISO will review these Applications with the TOs periodically and update the table of Applications as necessary.

The NYISO Staff shall review and approve any modified or newly proposed Applications of the Reliability Rules. Following approval, the NYISO shall notify the NYSRC and revise the table of TO Applications.

The NYISO may also propose revisions to or additional Applications of the Reliability Rules. The NYISO will work closely with the Transmission Owner to develop and implement these Applications.

The NYISO shall also review and approve any new or revised procedures developed by the TO associated with an Application.

Changes to the TO Application of Reliability Rules

The following process will be used to define new Applications of Reliability Rules or modification of existing Applications of the Reliability Rules:

1. The following entities can define new Applications of the Reliability Rules or modify existing Applications of the Reliability Rules:
   - ✧ NYISO
   - ✧ NY Transmission Owners

2. Applications of the Reliability Rules proposed by the TOs shall be referred to the NYISO for approval.
3. Once the NYISO concurs, it shall take two actions:
   - ✧ Include them in the next version of the NYISO Transmission and Dispatching Operations Manual, and
   - ✧ Advise the NYSRC.
4. The NYSRC shall post the updated Applications of the Reliability Rules on its web site.

Any incremental uplift costs incurred to meet Applications of the Reliability Rules shall be recovered by the NYISO through a statewide uplift charge if the Application secures a facility within the NYISO Secured Transmission System. Applications of the Reliability Rules may apply to facilities that are not included in the NYISO Secured Transmission System, but are implemented by the NYISO at the TO's request. Incremental uplift costs associated with such Applications shall generally be borne by the Load Serving Entities in the Zone or Zones of the TO(s) making the request.

The Application of the Reliability Rules and the associated cost allocations are listed in Table B.5 ATTB5 of this Manual.

2.1.6 NYSRC Local Reliability Rules

Local Reliability Rules (LRR) are a specific set of five rules defined in the New York State Reliability Rules and are maintained by the New York State Reliability Council (NYSRC). They apply to New York City (I-R1 through I-R4), and Long Island (I-R5).

I-R1 – Operating Reserves / Unit Commitment (New York City)

I-R2 – Locational Reserves (New York City)

I-R3 – Loss of Generator Gas Supply (New York City)

I-R4 – Thunderstorm Watch (New York City)

I-R5 – Loss of Generator Gas Supply (Long Island)

Transmission Owner LRR Responsibilities

The Transmission Owners are required to maintain procedures to comply with each NYSRC LRR. These procedures shall contain operational parameters that are developed based on studies performed by the TO. The NYSRC Reliability Rules require the NYISO to review and approve any updates to procedures or studies associated with the NYSRC LRRs.

.At times, TOs may propose modifications to the NYSRC LRRs or other Reliability Rules. Any proposed change to a Reliability Rule is required to be presented to the NYSRC for consideration by the NYSRC through the Reliability Rules development process. (See the appropriate NYSRC Policy at http://www.nysrc.org/policies.asp)

NYISO LRR Responsibilities

The NYISO Staff will review any new or revised procedures developed by the TO associated with the NYSRC LRRs.

The NYISO Operating Committee (OC) is responsible for review and approval of any operational parameters necessary to implement the Application associated with NYSRC LRRs.

The OC may require review and approval of any study or analysis that was completed to justify new or modifications of existing operational parameters.

The NYISO will post the Applications associated with all Local Reliability Rules in the table of Applications of the Reliability Rules on the NYISO's website (see Table B.5).

The LRRs of the New York TOs are listed in Table B.4of this Manual.

2.2 NYISO, Transmission Owner, and Generator Owner Responsibilities and Authorities

The following defines the responsibilities and authorities assigned to the NYISO, TOs, and Generator Owners.

2.2.1 Background Definitions

New York State Transmission System (NYSTS)

The New York State Transmission System (NYS Transmission System) includes: (1) the Transmission Facilities Under NYISO Operational Control; (2) the Transmission Facilities Requiring NYISO Notification; and (3) all remaining transmission facilities within the NYCA.

Local Area Transmission System Facilities are the Transmission Facilities and the sub-transmission facilities that are not included in Table A.1 of this Manual.

New York State Power System (NYSPS)

The New York State Power System includes all facilities of the NYS Transmission System and all those Generators located within New York or outside New York, some of which may be from time-to-time subject to operational control by the NYISO.

Thus,

NYSPS = NYSTS + Internal/External Generators Subject to NYISO Operational Control

Reliability Rules

Those rules, standards, procedures, and protocols developed and promulgated by the NYSRC (in accordance with NERC, NPCC, FERC, PSC, and Nuclear Regulatory Commission (NRC) standards, criteria, rules and regulations, and other criteria) and the LRRs pursuant to the NYSRC Agreement.

NYISO Secured Transmission System

Certain transmission facilities in the NYS Transmission System that the NYISO will be responsible to secure through: (1) the coordination of the operation of those facilities under its Operational Control with the responsible TOs, (2) the commitment and/or dispatch of supply and demand resources connected to the NYS Transmission System, and/or (3) the control and/or coordination of system elements used to provide ancillary services.

All the facilities in the NYISO Secured Transmission System are identified in Table A.1 of this Manual. Bus Voltage Limits for buses included as part of the NYISO Secured Transmission System are listed in Table A.2 of this Manual.

Therefore:

1. A Transmission Facility may be under NYISO Operational Control ***but not*** part of the NYISO Secured Transmission System.
2. A Transmission Facility may be subject to NYISO Notification (i.e., not under NYISO Operational Control), and yet be part of the NYISO Secured Transmission System.
3. NYISO Secured Transmission System Facilities designated on the NYISO Operational Control and/or NYISO Notification Lists will be secured by the NYISO only in terms of flows on those facilities. NYISO Secured Transmission System Facilities designated on the Bus Voltage Limit list will be secured by the NYISO in terms of voltages at those buses.
4. Maintenance of the Normal State by the NYISO, and declaration of the Alert, Warning, Major Emergency, and Restorative States by the NYISO will pertain to the NYISO Secured Transmission System only.

2.2.2 General Relationships between NYISO and Transmission Owners

Operation of the NYS Power System will be a cooperative effort coordinated by the NYISO Control Center in conjunction with each TO's Control Center, and will require instantaneous exchange of all scheduling information.

In general, the NYISO will have operational control over key transmission facilities and it will be notified of any change in status for other facilities.

The NYISO enforces the Reliability Rules for the NYISO Secured Transmission System. Certain applications of the Reliability Rules, previously implemented by the TOs, will continue to require close coordination between the TOs and the NYISO to maintain the reliability of the NYS Power System.

2.2.3 NYISO Responsibilities and Authorities

The primary responsibilities and authorities of the NYISO are:

1. Control Area operations of the NYS Power System.
2. Perform balancing of generation and load while maintaining the safe, reliable, and efficient operation of the NYS Power System.

3. Mitigate the impact of Constraints on the NYS Transmission System, including nondiscriminatory redispatch and Curtailments.
4. Maintain the NYISO Secured Transmission System in Normal State based upon reliability criteria, and declare Warning, Alert, Major Emergency, and Restorative States for the NYISO Secured Transmission System.
5. Exercise Operational Control over certain facilities of the NYS Power System under normal operating conditions and system Emergencies to maintain system reliability. For the NYISO Secured Transmission System, maintain appropriate flows and voltage levels during normal operations and order adjustments to be made under emergency conditions.
6. In the event of, or to prevent, a Major Emergency State, Eligible Customers shall comply with all directions from the NYISO concerning the avoidance, management, and alleviation of the Major Emergency and shall comply with all procedures concerning Major Emergencies set out in the NYISO Procedures and the Reliability Rules.
7. Under adverse conditions (as defined above), the NYISO will direct the adjustment of Generator output levels in certain areas of the NYS Power System to reduce power flows across the vulnerable transmission lines to reduce the likelihood of a major power system disturbance. The NYISO shall have the authority to declare that adverse conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYS Power Systems under NYISO control in response to those conditions.
8. Maintain the safety and short-term reliability of the NYS Power System.
9. Coordinate NYS Power System equipment outages and maintenance.
10. Approve maintenance schedules for Transmission Facilities under NYISO Operational Control based on approved criteria.

2.2.4 Transmission Owner Responsibilities and Authorities

The primary responsibilities and authorities of each TO are as follows:

1. Implement the Reliability Rules for those portions of the NYS Transmission System not included in the NYISO Secured Transmission System.
2. Coordinate with the NYISO to implement certain applications to the Reliability Rules where the NYISO lacks the necessary expertise and/or monitoring capabilities.
3. Physically maintain and operate Table A.1 facilities under direction and control of the NYISO to assure secure operation of the NYISO Secured Transmission System.
4. Comply with maintenance schedules coordinated by the NYISO for Table A.1 facilities.
5. Recommend activation of applicable procedures for adverse conditions associated with a Local Reliability Rule to the NYISO. The TO and the NYISO shall coordinate implementation of the procedures that impact Table A.1 facilities.

6. Notify NYISO prior to any planned outage and notify the NYISO of any change in status of Table A.1 facilities requiring NYISO notification.
7. Physically maintain and operate Table A.1 facilities requiring NYISO notification.
8. Operate Local Area Transmission System Facilities, provided it does not compromise the reliable and secure operation of the NYS Transmission System.
9. Promptly comply, to the extent practical, with a request from the NYISO to take action with respect to coordination of the operation of its Local Area Transmission System facilities.
10. Take action with respect to the operation of its facilities, as it deems necessary to maintain Safe Operations. Promptly conduct investigations of equipment malfunctions and failures, significant forced transmission outages, and provide a report of such investigations to the System Protection Advisory Subcommittee.
11. Determine the level of resources to be applied to restore facilities to service following a failure, malfunction, or forced transmission outage.
12. Each TO shall continue to receive telemetry from existing Generators in its control center and provide for the receipt of such information from new Generators.

2.2.5 Generator Owner Responsibilities

The responsibilities of the Generator Owners include Generator Response during Reserve Activation as follows:

Dispatchable Generating Units Not Providing Regulation Service

All non-wind units that are NOT “self-committed fixed” or “ISO-committed fixed” are expected to respond to a reserve pickup 10-minute basepoint at its emergency response rate as bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its Real-Time Dispatch (RTD) basepoint, which will be consistent with the LBMP, within three (3) RTD intervals (approximately 15 minutes) following termination of the reserve pickup. The unit will also be paid for overgeneration during that grace period.

Generating Units Providing Regulation Service

A unit providing regulation service is expected to respond to a reserve pickup 10-minute basepoint at its stated response rates as bid. If the unit exceeds the given basepoint within the reserve pickup, it will be paid for the overgeneration. However, the unit must return to its RTD/Automatic Generation Control (AGC) basepoint, within three (3) RTD intervals following termination of the reserve pickup. The unit will be paid for overgeneration during the three (3) RTD interval grace period. Limited Energy Storage Resources (LESRs) do not participate in reserve pickups except as follows:

1. If they are consuming (charging) when the event is called, AGC will move the LESR to a zero output position and

2. If they are injecting (discharging), AGC will maintain their current output subject to any energy limitations.

2.3 Normal and Warning Operating States

This section of the manual discusses the criteria for the Normal and Warning States.

2.3.1 Definition of Normal State

The Normal state exists when all conditions are within their normal boundaries and rating limits or after facilities have returned to within their normal operating limits. Imminent or immediate operator action is not necessary.

2.3.2 Normal State Criteria

All of the following criteria must be met for the NYCA to be operating in the Normal State:

1. Pre Contingency (Actual) Flow Criteria:

Normal Transfer Criteria: Actual loading of equipment defined as the NYS Transmission System does not exceed their associated Normal ratings.

2. Post Contingency Flow Criteria:

Single Circuit and Two adjacent circuits on same structure Criteria:

- ***Normal Transfer Criteria:*** Loss of any single generator, single circuit, or adjacent circuits on the same structure, together with other facilities, which will trip at the same time due to pre-set automatic devices, will not cause any portion of the NYS Transmission System to exceed its Long Term Emergency (LTE) rating.

The following are exceptions to the criteria.

- The Post-Contingency loading of any underground cable may exceed its LTE rating, but not its Short Term Emergency (STE) rating, provided 10-minute reserve or phase angle control is available to return its post- contingency loading to its LTE rating within 15 minutes, without causing another facility to be loaded beyond its LTE rating.
- With prior approval of the NYISO, the post-contingency loading of any portion of the NYS Transmission System may exceed its LTE rating, provided sufficient control is available to return the loading on the facility to its LTE rating within 15 minutes, without causing another facility to exceed its LTE rating.
- Multiple circuit towers used only for station entrance and exit purposes, which do not exceed five towers at each station, are not considered adjacent circuits on the same structure. (For specific exceptions, see Table B.2 of this Manual.)
- Actual voltages on all buses listed in Table A.2 and Table A.3, of this Manual are within pre-contingency limits.

3. Sufficient Operating Reserve exists to meet the requirements specified by the NYSRC.

4. NYS Power System stability limits and post-contingency flow limits associated with a voltage collapse are not exceeded.
5. Area Control Error is no greater than +/- 100 MW, or not more than +/- 500 MW for more than 10 minutes.
6. Power system frequency is not less than 59.95 Hz or greater than 60.05 Hz.
7. All communications facilities, computers, control, and indication equipment necessary to monitor these criteria are available.
8. All neighboring Control Areas are operating under Normal State conditions.

2.3.3 Definition of Warning State

The Warning state exists when specified limits have transgressed beyond the Normal state but do not severely impact or limit the operation of the NYISO Secured Transmission System unless they remain unchecked. Operator action may be required to return the system to the Normal state.

2.3.4 Warning State Criteria

The Warning State exists when any of the following conditions occur:

1. Pre Contingency (Actual) Flow Criteria:

   Normal Transfer Criteria: The actual loading on any portion of NYISO Secured Transmission System is 105% or more of its associated Normal Rating, but is less than the LTE rating for not more than 30 minutes or exceeds its Normal Rating by less than 5% and corrective actions are not effective within 10 minutes.

   Emergency Transfer Criteria are invoked: The actual loading of any NYISO Secured Transmission System facility does not exceed its associated Normal rating.
2. Post Contingency Flow Criteria:

   Normal Transfer Criteria: A condition exists for not more than 30 minutes and the predicted post-contingency loading of a NYISO Secured Transmission System facility will exceed its associated LTE rating but not its STE rating.

   Emergency Transfer Criteria are invoked: The loss of any single generator or circuit, together with other facilities, which will trip at the same time due to pre-set automatic devices, will not cause any NYS Transmission System facility to exceed its STE rating.
3. Sufficient Operating Reserve exists to meet the requirements specified by the NYSRC, but only using Emergency Transfer Criteria.
4. Area Control Error is greater than +/- 100 MW, but not more than +/- 500 MW for more than 10 minutes.
5. A neighboring Control Area is not operating under Normal State conditions, but has not implemented voltage or load reduction.
6. An Operating Reserve deficiency is predicted for the NYCA peak load forecast and reserve purchases are not available.

2.4 Market Operations Time Line

Operation of the NYCA and the Locational Based Marginal Pricing (LBMP) Market involves many activities that are performed by different operating and technical personnel. These activities occur in parallel on a continuous basis, 24 hours a day.

Figure 2-1 summarizes the important events that characterize the day-to-day operation of the NYISO LBMP market. Although this Manual focuses mainly on dispatch day activities, it is important to understand how day-ahead activities can impact real-time operation.

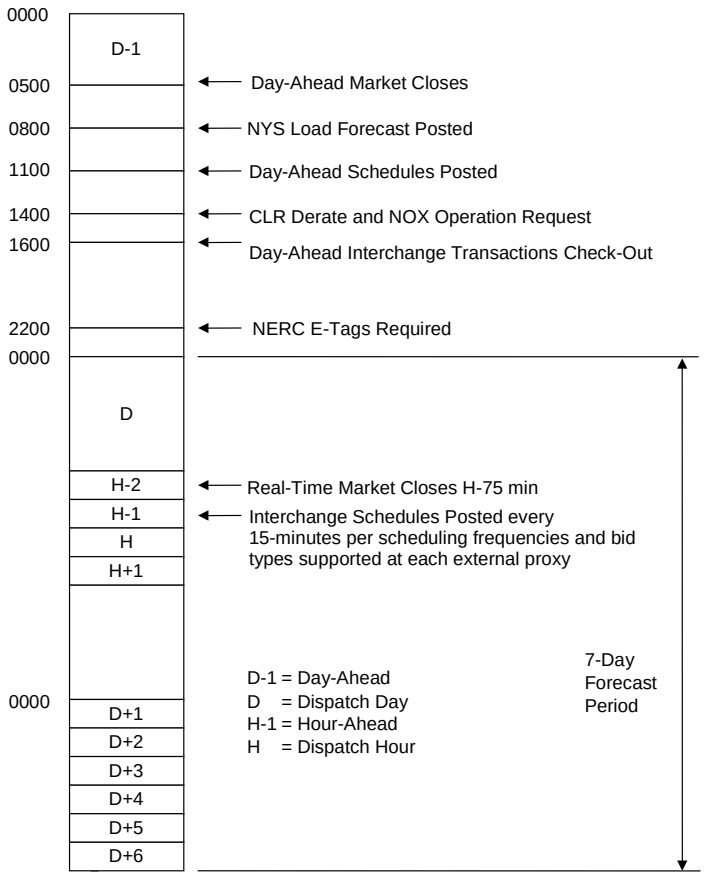

Figure 2-1 Energy Market Operations Timeline

For more information, see the *NYISO Day Ahead Scheduling Manual*, available from the NYISO Web site at the following URL:

http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp

The activities shown by the time line are described briefly as follows:

1. ***0500 (D-1):*** Closing time of the day-ahead energy market.
2. ***0800 (D-1):*** The load forecast for the State of New York is posted.
3. ***1100 (D-1):*** The results of the day-ahead security constrained unit commitment (SCUC) are posted.
4. ***1400 (D-1):*** Deadline for Capacity Limited Resources (CLRs) to submit requests for derates and for NOX impacted entities to submit requests for steam unit operation.
5. ***1600 (D-1):*** Day-ahead external interchange transaction checkout has been completed.
6. ***2200 (D-1):*** Deadline for NERC E-Tags to be submitted for external interchange transactions.
7. ***xx45 (H-2):*** Closing time of the real-time energy market.
8. ***Starting with xx15 (H-1):*** The Real-Time Commitment (RTC) application, that executes periodically every 15 minutes. The execution at xx15 posts the upcoming "Dispatch Hour" external interchange transaction schedules for hourly transactions, while every execution posts the interchange transaction schedules for intra-hour transactions according to the scheduling frequency supported at each external proxy.
9. ***xxxx (H):*** The dispatch hour with locked offers/bids and interchange transactions.

Dispatch Day

The 24-hour period commencing at the beginning of each day (0000 hour).

Dispatch Hour

The 60-minute period commencing at the beginning of each hour of the dispatch day (xx00 hour).

Real-Time

The following applications are said to execute in "real-time":

- ***Real-Time Commitment (RTC)*** – executes every 15 minutes as described in this Manual.
- ***Real-Time Automated Mitigation Process (RT-AMP)*** – executes every 15 minutes as described in this Manual.
- ***Real-Time Dispatch (RTD)*** – executes every 5 minutes as described in this Manual.
- ***Real-Time Dispatch/Corrective Action Mode (RTD-CAM)*** – executes on demand as described in this Manual
- ***Automatic Generation Control (AGC)*** – executes every 6 seconds as described in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

2.5 Operations Functions

The following areas are covered by the operations functions described in this Manual:

- NYISO Secured Transmission System Monitoring
- Transmission System Operation
- Energy Market Overview
- Energy Market Functions
- Backup Operations

2.5.1 NYISO Secured Transmission System Monitoring

The NYISO Secured Transmission System is monitored on a continuous basis to evaluate its current operating state. The first step in this process is to determine which of the five States the NYISO Secured Transmission System is in. This Manual covers the Normal and Warning States.

The monitored conditions of critical concern include:

- System Load and Operating Reserves
- Regulation capability
- NYISO Secured Transmission System flows and voltages
- NYCA Control Error
- This section discusses the power system monitoring requirements and procedures in further detail.

2.5.2 Transmission System Operation

The operation of the NYISO Secured Transmission System reflects the criteria that have been established for existing conditions as well as for anticipated contingency conditions. This Manual defines the secure operation of the NYISO Secured Transmission System as well as the corrective measures that need to be taken to maintain secure operation.

Section 3 of this Manual discusses the transmission system operational requirements and procedures in further detail.

2.5.3 Energy Market Overview

A review of market mechanics is presented in Figure 2-2 as an introduction to the dispatch day functions. Sections 5 and 6 of this Manual provide further detail.

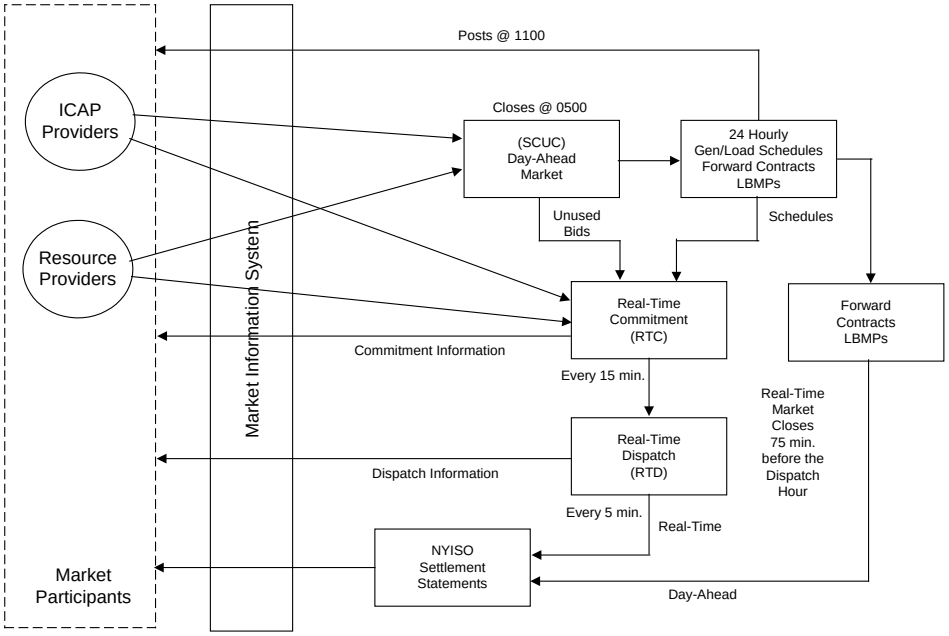

Figure 2-2 Market Overview

2.5.4 Energy Market Functions

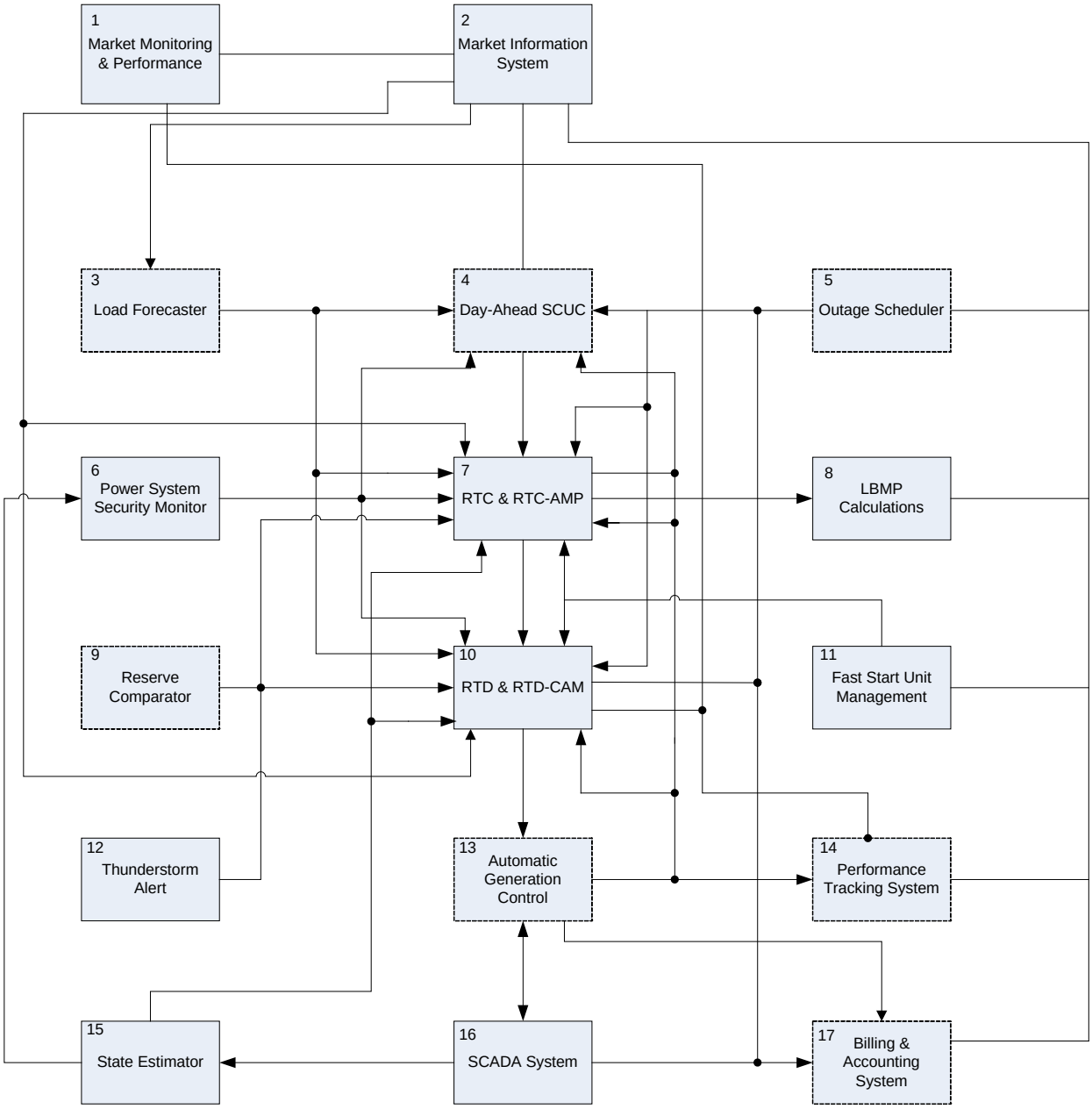

Figure 2-3 Day-Ahead and Dispatch Day Functions

The following is a brief summary of each function block in Figure 2-3. The dotted boxes are described in more detail in other NYISO Manuals:

1. ***Market Mitigation & Analysis Department (MMA):*** The MMA Department is charged with analyzing market participant bids and their impact on energy market prices. MMA applies mitigation measures in the event that it detects conduct that is inconsistent with competition, e.g., physical withholding.
2. ***Market Information System (MIS):*** The MIS is the primary user interface between market participants and the NYISO. Market information is received

and posted via the MIS. Refer to the NYISO Market Participant User's Guide for details.

3. ***Load Forecaster (LF):*** The LF application produces NYCA load forecasts for SCUC, RTC, and RTD. Refer to the NYISO Day-Ahead Scheduling Manual for details.
4. ***Day-Ahead Security Constrained Unit Commitment (SCUC):*** The SCUC program establishes the outcome of the day-ahead market (DAM) based on forecast conditions and NYS Power System reliability requirements. SCUC executes over a 24-hour load forecast horizon to produce startup, shutdown, and hourly energy schedules for the resources that have bid into the DAM. Refer to the NYISO Day-Ahead Scheduling Manual for details. The SCUC model serves as the basis for deriving the Day-Ahead Market transmission loss and congestion sensitivity coefficients.
5. ***Outage Scheduler (OS):*** The OS function maintains a record of planned and forced power system facility outages and their scheduled return to service. Outage information is available to the market applications and to the power system analysis applications. Refer to the NYISO Outage Scheduling Manual for details.
6. ***Power System Security Monitor:*** The power system security monitoring applications assess forecasted and actual power system conditions and the impact of potential contingencies. These applications also establish the list of facilities the operating limits of which must be observed by the market applications.
7. ***Real-Time Commitment (RTC) & Real-Time Automated Mitigation Process (RT-AMP):*** The RTC and RT-AMP functions execute periodically on a 15-minute basis with a 2¼-hour look-ahead horizon, and post their commitment and scheduling results on the quarter hour (15, 30, 45, 00).
8. ***LBMP Calculations:*** The RTC and RTD programs produce LBMPs for market advisory and settlement purposes.
9. ***Reserve Comparator (RC):*** The RC program compares actual NYCA reserves, by category, against their corresponding requirements. Refer to the NYISO Ancillary Services Manual for details.
10. ***Real-Time Dispatch (RTD) & RTD-Corrective Action Mode (CAM):*** The RTD function executes periodically on a 5-minute basis with a 50, 55, or 60-minute look-ahead horizon, and posts its results on the five-minute clock times. The RTD-CAM functions override the normal RTD executions, as determined by the NYISO Operators, to deal with "off-normal" power system conditions. The RTD model serves as the basis for deriving the Real-Time Market transmission loss and congestion sensitivity coefficients.
11. ***Fast Start Unit Management (FSM):*** The FSM function provides the facility for the NYISO Operators to coordinate the commitment schedules produced by RTC and RTD-CAM. The FSM is used to approve/disapprove commitment schedules from RTC/RTD-CAM, and to manually commit/decommit other fast-start units.

12. ***Thunderstorm Alert (TSA):*** TSA is declared by NYISO Operators when severe operating conditions are detected. A predetermined set of pre- and post-contingency constraints are passed to the RTC and RTD programs while TSA is in effect.
13. ***Automatic Generation Control (AGC):*** The AGC program regulates the generation resources to balance load, generation, and interchange and help to maintain the Eastern Interconnection power system frequency. Refer to the NYISO Ancillary Services Manual for details.
14. ***Performance Tracking System (PTS):*** The PTS monitors the on/off-line status of generating units and their actual MW output versus their scheduled output. Refer to the NYISO Ancillary Services Manual for details.
15. ***State Estimator (SE):*** The SE produces an accurate real-time model of the NYS Power System, including a representation (equivalent) of the power system external to the NYISO. The SE is used to verify metered data and to estimate data values that are not metered.
16. ***Supervisory Control & Data Acquisition (SCADA) System:*** The SCADA system provides direct communications between the NYISO Control Center and the remote transmission owner and power plant control centers. The NYISO transmits (telemeters) desired control actions to the remote control centers and receives current operational feedback data from these control centers.
17. ***Billing & Accounting System (BAS):*** The BAS itemizes those data elements that are stored or produced by the various subsystems so that line item settlement statements can be calculated after-the-fact on a monthly basis. Refer to the NYISO Accounting & Billing Manual for details.

2.5.5 Backup Operations

The Backup Operations is a comprehensive set of procedures that address the possible loss of functionality of the NYISO Control Center, TOs' Control Centers, and NYISO/TO communications facilities. Backup Operations is comprised of the following principle components and procedures:

- Manual Dispatch Systems – NYISO Power Control Center (PCC) & NYISO Alternate Control Center (ACC)
- Market Suspension Criteria
- Interim NYCA Operation – Transition period between PCC and ACC operation
- NYISO Alternate Control Center

Figure 2-4 illustrates the components that comprise backup operations. For details, refer to the *NYISO Backup Operations Manual* (available from the NYISO Web site at http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

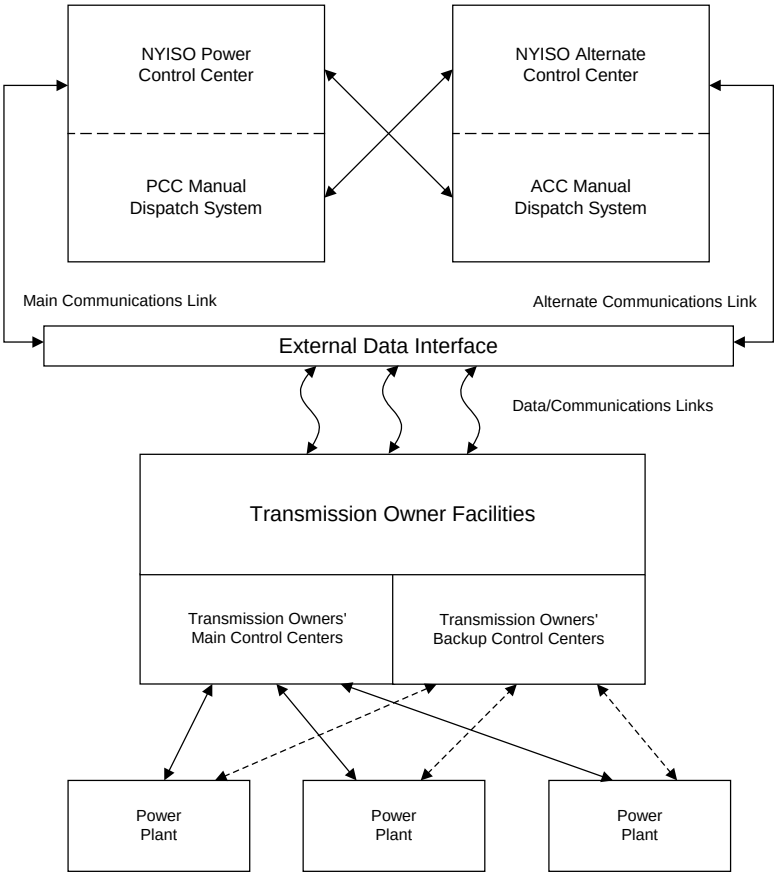

Figure 2-4 Backup Operations Configuration

2.6 Communications

This subsection describes the NYISO hotline and interregional communications systems.

2.6.1 Hotline Communications

The NYISO Hotline can be operated in two ways:

- Initiated by the NYISO
- Initiated by a Local TO Control Center

Initiated by the NYISO Shift Supervisor

A single pushbutton is used by the NYISO Shift Supervisor to ring a hotline phone in each local TO Control Center. The communications is two-way broadcast. That is, if a local TO Control Center operator speaks, it is heard by all the hotline phones.

Initiated by a Local Control Center System Operator

A local TO Control Center System Operator can call the NYISO Shift Supervisor on the hotline. In this situation, the NYISO Shift Supervisor hotline is the only hotline phone that

rings. TOs' Control Center System Operators should only use this method of communication with the NYISO Shift Supervisor under urgent conditions.

Interregional Communications Network

When the NYISO receives information via the NERC conference feature, it is relayed to Ontario, Hydro-Quebec, and New England by means of automatic ringdown leased lines. If the information is of an emergency nature, those three locations may be conferenced together for one announcement. ISO-NE relays the information to the Maritimes via an automatic ring-down leased line to New Brunswick. Figure 2-5 illustrates the interregional communications network.

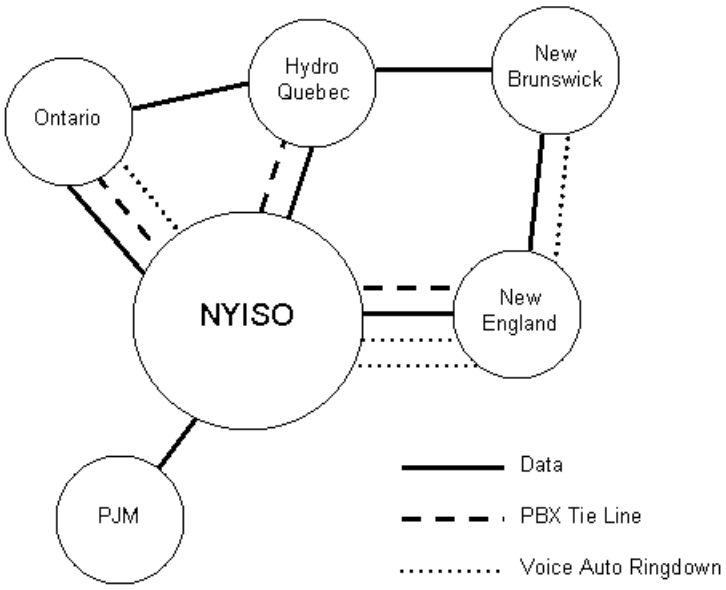

Figure 2-5 Interregional Communications Network

3. OPERATIONS MONITORING

This section describes the NYS Power System operations monitoring requirements and procedures.

3.1 Operations Monitoring Requirements

This section identifies the requirements for monitoring the operation of the NYCA. The conditions that are monitored include the following:

- Current Operating State
- System Load
- Operating Reserve
- Regulation
- NYISO Secured Transmission System
- Ancillary Services
- Communications
- Weather Conditions
- Telemetered Data

Reliability Assessment

The NYISO performs a Real-Time assessment of the reliability of the NYISO Secured Power System periodically upon status change, and upon operator demand. The main functions that are performed are:

- Real-Time Data Monitoring and Alarming
- DC Thermal Security Analysis
- Reserve Calculation
- Regulation Requirement

3.1.1 Real-Time Data Monitoring and Alarming

This function is executed, nominally every six (6) seconds for SCADA data and thirty (30) seconds for state estimated values.

NYISO Actions

The following are performed:

1. Determines whether to use: (1) metered values (2) state estimated values or (3) NYISO override/substitution values for:

   a. Switch status data
   b. Analog data

2. Checks the analog data against limits for voltage, flows on lines and transformer banks, and interface flows.

3. Finds and opens "modeled" breakers corresponding to non-metered outaged facilities, based on NYISO activation.
4. Executes the network configuration function, which processes the user switch data from (1) and (3) above.
5. Derives confirmation page alarms for NYISO review and validation.
6. Produces the following results:

a. User analog data
b. Audible alarms, text alarms, mimic board outputs
c. Confirmed switch status
d. Updated outage schedules

3.1.2 Security Assessment

The security assessment is triggered to execute on:

- Network configuration status change
- Periodic, nominally every 30 seconds
- Operator demand

NYISO Actions

The following are performed:

1. Executes the network configurator and state estimator functions based on confirmed switch status
2. Performs a contingency analysis based on the state estimator solution of the NYS Transmission System, using:

a. Pre-defined single and multiple contingencies
b. Facility Line ratings and interface transfer limits
c. Active RTD constraints

3. Produces a list of potential transmission system violations for NYISO Operations review based on actual SCADA (actual violations only) or state-estimated values (contingency violations only).

3.1.3 Reserve Calculation

The NYISO monitors NYCA reserve every five minutes (Reserve Monitor Program using actual generation). These reserve calculations indicate the reserve available for the NYCA. Corrective action is taken by the NYISO only if the NYCA is deficient in reserve. Reserve calculations and constraints are also performed by RTC and RTD.

Minimum Operating Reserve Requirement

The Minimum Operating Reserve Requirement of the NYCA is defined as:

1. Sufficient Synchronized Reserve Available in 10 minutes to replace one-half of the operating capability loss caused by the most severe contingency observed

under Normal Transfer Criteria multiplied by the contingency reserve adjustment factor.

2. Sufficient Reserve Available in 10 minutes (which includes synchronous reserve available in 10 minutes) to replace the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria multiplied by the contingency reserve adjustment factor.
3. Sufficient Reserve Available in 30 minutes (which includes reserve available in 10 minutes) equal to one and one-half times the operating capability loss caused by the most severe contingency observed under Normal Transfer Criteria.
4. Sufficient Reserve in 10 minutes to return the system to a Normal State following the most severe transmission contingency multiplied by the contingency reserve adjustment factor.

At all times sufficient 10 Minute Reserve shall be maintained to cover 1) the energy loss due to the most severe Normal Transfer Criteria contingency within NYCA or 2) the energy loss associated with recallable import transactions from another control area, whichever is greater.

3.1.4 Regulation Requirement

The NYCA Regulation requirements, in MW/minute, are established by analyzing NYCA daily load patterns and actual operating conditions. The NYISO establishes the regulation and frequency response requirements consistent with criteria established by NERC, which may vary by hour and season.

This Manual describes the process by which the NYCA regulation requirement is allocated to the generating units.

The NYISO will determine the amount of regulation required for different time periods and load conditions in accordance with procedures defined in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

The amount of Regulation Service required varies on an hourly and seasonal basis. The NYCA regulation requirements are posted on the NYISO website at the following URL: http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_regulation_req.pdf

3.1.5 Operations Monitoring Procedures

This section describes the procedures associated with monitoring the operation of the NYS Power System. General procedures dealing with the Normal State and Warning State are given first, followed by specific procedures to be carried out under Normal and Warning State conditions.

Specific procedures cover the following:

- Response to Normal State Conditions
- Response to Warning State Conditions

- Reliability Assessment Support
- Automatic Voltage Regulators / Power System Stabilizer Outages
- Communication of NYCA Operating Conditions
- Hourly Inadvertent Accounting
- Local Reliability Rules
- Applications of the NYSRC Reliability Rules
- Daily Operation for Monitoring Operating Reserve

3.1.6 Response to Normal State Conditions

NYISO Actions

The NYISO shall monitor NYS Power System conditions at all times, and determine and apply the applicable actions listed below that are necessary to remain in the Normal State:

1. Coordinate actions with TOs and other Control Areas.
2. Initiate one or more of the following actions:

a. Adjust phase angle regulators.
b. Shift or start generation by NYISO request to obtain additional reactive power (MVAr) control.
c. Activate reserves.
d. Adjust reactive sources and transformer taps.
e. Perform Generation shifts.
f. Modify Interchange Schedules.
g. Request NYS Transmission System facilities that are out of service for maintenance to be returned to service.
h. For high voltage conditions only, request NYS Transmission System facilities that are in service to be removed from service where appropriate.
i. Implement manual voltage reduction.
j. May call for a reserve pickup to return to schedule if the NYISO Area Control Error exceeds 100 MW.
k. Take actions to maintain operating reserve, in accordance with the procedures described in this Manual.

Transmission Owner Actions

NYISO operational contact is generally with the TO. The TOs are responsible for controlling or coordinating the operation of Generators connected to their systems, as follows:

1. Coordinate and implement corrective actions, as requested by the NYISO Shift Supervisor.
2. Monitor conditions with respect to their own systems.
3. Perform the following actions when the NYCA is operating in the Normal State and Normal State Criteria are not met:

a. Notify the NYISO Shift Supervisor.
b. Request assistance from the NYISO Shift Supervisor, as required.
c. Initiate unilateral corrective action, if the violation is severe enough to require immediate action.

Other Considerations

1. All schedule changes should be analyzed in advance of implementation in an effort to avoid violation of the Normal State criteria.
2. The NYISO shall dispatch the system such that the removal of any facility for scheduled work will not result in the violation of these criteria in the Normal State. Transmission Owners are responsible for providing appropriate advance notice of such switching.
3. During periods when adverse conditions such as tornadoes or hurricanes exist, or are forecast to occur within the service area of the NYISO Systems, it may be necessary to take steps in addition to those procedures normally followed to maintain system security.
4. It is the responsibility of the NYISO to monitor weather conditions and forecasts issued by the National Weather Bureau. Should local adverse conditions occur or if they are predicted to occur, it is the responsibility of the TO to inform the NYISO. If a situation involving impending severe weather exists, the NYISO shall notify all TOs and consider declaration of the Alert State.
5. The actual voltage on all busses listed in Table A.2 and Table A.3 shall be monitored by the NYISO and TOs. It shall be the TO responsibility to maintain voltage levels within limits specified in Table A.2 and Table A.3 and to coordinate actions, which would affect voltage levels on busses of other TOs or Neighboring Systems.

   If the NYISO anticipates conditions, which would cause the voltage at any bus listed in Table A.2 and Table A.3 to violate Normal State Criteria, the NYISO shall notify the TOs, and together they shall formulate a corrective strategy. If implementation of the corrective strategy does not produce the desired result, and the NYISO determines that further corrective action is necessary to remain in the Normal State, the NYISO shall request such actions in accordance with Normal State Responses. TOs must coordinate and implement corrective actions as requested by the NYISO.
6. It may be necessary to schedule energy transactions from neighboring control areas for reliability reasons in accordance with Interconnection Agreements.

3.1.7 Response to Warning State Conditions

NYISO Actions

The NYISO shall monitor system conditions at all times and determine the action(s) listed below that are necessary to return the system to the Normal State:

1. Coordinate actions with TOs and other Control Areas.

2. Initiate one or more of the following actions:

a. Adjust phase angle regulators.
b. Shift or start generation by NYISO request to obtain additional reactive power (MVAr) control.
c. Activate reserves.
d. Adjust reactive sources and transformer taps.
e. Perform Generation shifts.
f. Modify Interchange Schedules.
g. Request NYS Transmission System facilities that are out of service for maintenance to be returned to service.
h. For high voltage conditions only, request NYS Transmission System facilities that are in service to be removed from service where appropriate.
i. Implement manual Voltage Reduction.
j. May call for a reserve pickup to return to schedule if the NYISO Area Control Error (ACE) exceeds 100 MW.
k. Take actions to maintain operating reserve, in accordance with the procedures described in this Manual.
l. Curtail non-essential TO and Generation Owner load.
m. Order Generation to full operating capability.

3. Take the following actions if the above measures are insufficient to comply with Normal Transfer Criteria within 30 minutes or Operating Reserve cannot be delivered due to transmission limitations for 30 minutes:

a. Notify all TOs, via the Hotline communications system, that Emergency Transfer Criteria are in effect for the facility (ies) involved.
b. Take actions, as required, to stay within Emergency Transfer Criteria.
c. Confer with TOs that will have Post-Contingency loading or voltage conditions that exceed allowable limits. Jointly develop strategies to be followed in the event a contingency occurs, including preparation for a rapid Voltage Reduction and/or Load Shedding.

4. If following the implementation of the actions listed above all Normal State criteria cannot be achieved, satisfy as many of the Normal State criteria as possible.

Transmission Owner Actions

Transmission Owners shall perform the following actions:

a. Coordinate and implement corrective actions, as requested by the NYISO Shift Supervisor.
b. Monitor conditions with respect to their own systems.
c. Perform the following actions when the NYCA is operating in the Warning State and Warning State Criteria are not met:
d. Notify the NYISO.
e. Request assistance from the NYISO, as required.

f. Initiate unilateral corrective action, if the violation is severe enough to require immediate action.

Other Considerations

1. For all contingencies that would result in a violation of the Warning State criteria, corrective action that would be necessary if the contingency occurs shall be determined through coordination between the NYISO and the affected TO.
2. If the NYISO foresees an extended period of operation in the Warning State, a canvass of the TO Systems shall be made to determine if assistance can be provided.
3. If the situation involving impending adverse conditions exists, the NYISO shall notify all TOs and consider declaration of the Alert State.

3.1.8 Reliability Assessment Support

NYISO Actions

The NYISO shall perform the following actions in support of the Reliability Assessment function:

1. Execute the Reliability Assessment function on demand following a power system disturbance.
2. Override and substitute SCADA analog and status data that is incorrect or missing.
3. Activate outages in the network model by “opening” the appropriate breakers or switches in the model.
4. Review and acknowledge any alarm messages.
5. Review the “Confirmation” display and make any necessary corrections or adjustments to the incoming data.
6. Review and acknowledge potential transmission system violations produced by the state estimator and Security Analysis functions.

3.1.9 Automatic Voltage Regulator / Power System Stabilizer Outages

NYISO Actions

The NYISO shall perform the following actions:

1. Coordination of generating unit Automatic Voltage Regulator (AVR) and Power System Stabilizer (PSS) outage requests provided the following criteria have been met:

a. No more than six AVRs shall be allowed out-of-service simultaneously throughout the NYCA, with a limit of three in the Area east of the Central/East Interface, and three more west of the Central/East Interface.

b. No more than one generating unit PSS shall be allowed out-of-service throughout the NYCA. If a generating unit PSS is out-of-service, then ensure all applicable system transmission limits have been adjusted to account for such outages.

2. Maintain a log of the AVRs and PSSs taken out-of-service and their return to service. The form is shown in Attachment D and shall be included with the daily transmission outage summary sheets.

Generator Owner Actions

Generator Owners shall coordinate the outage of AVRs and PSSs on generating units with 40 MW capability or larger with the NYISO.

3.1.10 Communication of New York Control Area Operating Conditions

NYISO Actions

The NYISO shall perform the following actions:

1. Obtain the following data for the NYCA Report, prior to 0530 hours:
   - ✧ Generator anticipated operating capability for the NYCA peak hour, including all purchases and sales.
   - ✧ Forecast NYCA load requirements.
2. Determine the following information for the NY Control Capacity Report display, using the acquired data:
   - ✧ NYCA forecast peak hour load
   - ✧ NYCA reserve requirements
   - ✧ NYCA generation available capability
   - ✧ Interchange summary and peak hour Desired Net Interchange (DNI)
   - ✧ Total anticipated reserve for the NYCA peak hour
   - ✧ Previous day's peak load and hour
3. Post the NYCA Capacity Report.
4. Immediately report any critical change in the status of the NYCA, either via the emergency telephone system or the NYCA Status Report.
5. Report all NYCA disturbances, e.g., loss of a major generator, when appropriate.
6. Notify the NYISO designated media contact (or the designated alternate) when system conditions exist that would result in general public awareness of an actual or impending situation.

3.1.11 Hourly Inadvertent Accounting

The following procedures apply only to the NYISO. The *NYISO Accounting and Billing Manual* (available from the NYISO Web site at the following URL:

http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp) describes the Inadvertent Interchange accounting procedure in further detail.

NYISO Actions

The NYISO shall perform the following checks on an hourly basis:

1. *Prior to each hour* – The sum of External transaction schedules should be equal to the NYCA DNI schedule.
2. *After each hour* – The sum of the interconnection readings should be equal to the NYCA Actual Net Interchange (ANI).
3. *After each hour* – The NYCA Inadvertent Interchange should be equal to the difference between the DNI and ANI.
4. *After each hour* – Reconcile any inadvertent variances with neighboring Control Areas.
5. *After each day* – Reconcile any inadvertent variances with neighboring Control Areas.

3.2 Daily Operation for Monitoring Operating Reserve

The NYISO Shift Supervisor will monitor the Operating Reserve both as forecast for the expected system peak each day and under actual conditions as the day progresses.

Peak Load Forecast

The NYISO Shift Supervisor (or designee) shall prepare the NYISO daily status report twice daily, in anticipation of the morning peak and evening peak as indicated in this Manual.

If a shortage of energy, reserves, or Ancillary Services is projected, the NYISO will take actions as directed in the *NYISO Emergency Operations Manual*, available from the NYISO Web site at the following URL:

http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp

3.3 Periodic Monitoring of Fuel and Resource Availability

Installed Capacity (ICAP) Suppliers shall submit Fuel and Environmental Restriction Data to the NYISO on weekly and yearly intervals and as requested by the NYISO. All ICAP Suppliers shall complete the Fuel Availability Self Reporting Surveys as follows:

1. Yearly Fuel Surveys must be completed within 30 days of NYISO notification of its availability.
2. Weekly Surveys must be completed by 1:00 p.m. of the first business day of each week.
3. As Requested Surveys must be completed by 1:00 p.m. of the day prior to the operating day the survey is requested for.

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4. TRANSMISSION OPERATIONS

This section describes the NYS Transmission System operations requirements and procedures.

4.1 Transmission Operations Requirements

This section addresses the operation of the NYISO Secured Transmission System when it is in the Normal State or Warning State. The following requirements and guidelines are discussed:

- NYISO Secured Transmission System Operating Limits
- Corrective Control Strategies
- Transmission Service Reduction & Curtailment
- Solar Magnetic Disturbances

The Transmission Facilities Under NYISO Operational Control and subject to *Orders* from the NYISO are identified in Table A.1 of this Manual. The Transmission Facilities Requiring NYISO Notification are also identified in Table A.1.

4.1.1 NYISO Secured Transmission System Operating Limits

Limits that are used in the operation of the NYCA are classified as follows:

1. ***Thermal (Summer/Winter):*** MW

   Normal: Continuous

   Long Term Emergency (LTE): 4-hours within 24-hour period

   Short term Emergency (STE): 15-minutes

2. ***Voltage:*** kV

   Pre-contingency High/Low

   Post-contingency High/Low

3. ***Frequency:*** Hz

   Normal High

   Normal Low

4. ***Interface Transfer:*** MW

   Stability

   Voltage Collapse

4.1.2 Corrective Control Strategies

The major electrical network problems that can occur in the NYCA and the primary (or most effective) means of overcoming these problems are identified in Table 4.1. The major problems are:

- Facility overloads and excessive transfers
- NYISO Secured Transmission System low voltage conditions

- NYISO Secured Transmission System high voltage conditions
- System low frequency conditions
- System high frequency conditions

Table 4.1 Corrective Control Strategies

	NY Control Area Problems				
Typical Means of Control	**Overloads & Excess Transfer**	**Low Trans. Voltage**	**High Trans. Voltage**	**Low Frequency**	**High Frequency**
Generator MW	✓	✓	✓	✓	✓
Phase Angle Regulator (PAR)	✓	✓	✓		
Control Area Interchange	✓		✓		
Generator MVAr (AVR)		✓	✓		
Transformer Tap (LTC)		✓	✓		
Shunt Capacitor		IN	OUT		
Shunt Inductor		OUT	IN		
Synchronous Condenser MVAr (AVR)		✓	✓		
Static Var Compensation (SVC)		✓	✓		
Transmission Lines	✓		OUT		
Circuit Breaker	✓			✓	✓
PS Pump Operation	✓	✓	✓	OFF	ON
PS Generator Operation	✓	✓	✓	ON	OFF
Voltage Reduction	✓	✓		✓	
Load Curtailment	✓	✓		✓	
Load Shed	✓	✓		✓	

Some of the controls listed in Table 4.1 are automatically applied by local closed-loop control while other controls are acted on by the TOs upon NYISO request. The NYISO has no direct means (via SCADA) of controlling the generation, transmission, and distribution systems.

4.1.3 Transmission Service Reduction and Curtailment

Firm Transmission Service

If a Transmission Customer's Firm Transmission Service is supporting a Bilateral Transaction supplied by an Internal Generator and that Generator is dispatched downward, the NYISO shall not curtail the Transmission Service. The NYISO shall continue to supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market provided however, the NYISO shall reduce Transmission Service supporting a Export bilateral if the amount of Energy scheduled to be exported is reduced. The NYISO shall not reduce Transmission Service scheduled to support an Import with a non-reference bus sink even if the amount of Energy scheduled to be imported is reduced.

Non-Firm Transmission Service

If the Transmission Customer was receiving non-Firm Transmission Service and its Transmission Service was Reduced or Curtailed, the replacement Energy will be purchased in the Real-Time LBMP Market by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed will sell its Energy in the Real-Time LBMP Market.

The NYISO will not automatically reinstate non-Firm Transmission Service that was Reduced or Curtailed. Transmission Customers need to submit new schedules to restore the Transmission Service associated with their Transaction in the next RTC execution.

Negative Congestion

The following rules apply to negative congestion and non-firm transmission service:

1. Non-Firm transmission service that encounters negative congestion will not be curtailed. The rationale for this is that any transaction that relieves congestion should not be curtailed.
2. Non-Firm transmission service that encounters negative congestion will not be paid for the negative congestion. The rationale for this is as follows:

A non-firm transaction is not willing to pay positive congestion (and thereby reduce overall transmission costs); therefore, it should not be entitled to receive negative congestion costs. Furthermore, a payout of negative congestion to non-firms would increase overall uplift.

A transaction wishing to receive a payment for negative congestion can request firm transmission service for that transaction.

4.2 Transmission Operations Procedures

These procedures apply mainly to the operation of the NYISO Secured Transmission System network facilities. Procedures for the following are covered:

- Developing & Approving Operating Limits
- Voltage Control
- Guidelines for Leeds and Fraser SVCs to Control Voltage
- Phase Angle Regulators – ConEd/PSE&G

- Phase Angle Regulators Operations
- Implementing Special Multiple Contingencies
- Exceptions to the NYSRC Reliability Rules
- Security Violation Relief
- Operating Under Adverse Conditions
- Solar Magnetic Disturbances

4.2.1 Developing & Approving Operating Limits

Procedures have been established for the following:

1. The approval and implementation of operating limits developed from off-line computer studies conducted by the NYISO.
2. The collection of operating data required to determine voltage limits for selected buses in the NYCA.

NYISO Actions

The NYISO shall perform the following actions:

1. Prepare Seasonal studies of thermal transfer limits for the “all-lines in” condition.
2. Prepare stability transfer limits for the “all-lines in” condition. These limits will be used for the secure operation of the NYISO Secured Transmission System.
3. Prepare pre-contingency (high/low) and post-contingency (high/low) voltage limits for the “all-lines in” and prevailing conditions. These limits will be used for the secure operation of the NYISO Secured Transmission System.
4. Review and update the data maintained by the NYISO Data Bank program. This data will be used for network, stability and voltage control parameters, in preparation of seasonal, and/or for specific operating studies base cases.

NYISO Operating Committee Actions

The NYISO Operating Committee shall review and approve the recommended limits developed by the NYISO staff.

4.2.2 Voltage Control

These procedures are for coordinating and controlling the voltage of the NYISO Secured Transmission System and define the respective actions to be taken by the NYISO and the TOs. The purpose is to provide adequate voltages necessary to maintain power transfer capabilities and to keep voltages within prescribed limits to avoid damage to equipment.

NYISO Actions – General

The NYISO shall perform the following actions:

1. Anticipate the effects, voltage levels, and trends in the NYCA and adjacent Control Areas.

2. Determine and request corrective actions that need to be taken to remain in the Normal State.
3. Coordinate requests for corrective actions with the TOs and adjacent Control Areas that can assist in adjusting voltage on the buses being corrected.
4. Inform the affected TOs of anticipated changes in reactive support from pumped hydro units, Static Var Compensators, or neighboring Control Areas.
5. Request Generators (via their TOs) to adjust machine excitation as required to maintain desired NYISO Secured Transmission System voltages within limits.

Transmission Owner Actions – General

The TO shall perform the following actions:

1. Observe the status and availability of major reactive resources on its system and determine any restrictions on those sources.
2. Control the voltage on its transmission system to be within its internal limits. Under normal conditions, maintain reactive power flows on tie lines with adjacent Control Areas in accordance with mutually agreed upon schedules and NPCC Inter-Control Area Voltage Control Procedures.
3. Provide assistance (consistent with its internal limits) to other TOs as requested by the NYISO.
4. Coordinate and notify the operation (prior to execution) of the following devices with the NYISO and TOs: (1) switching of shunt capacitors and inductors and (2) changing of SVC mode or state. Under Emergency conditions a TO may perform the control actions prior to notification of the NYISO TO and affected TOs, but shall inform them as soon as possible.
5. Request Generators to adjust machine excitation as required to maintain desired voltages within limits.

NYISO Actions – High-Voltage Conditions

The NYISO shall request the TOs to perform the following normal steps to alleviate high voltage conditions:

1. Switch out shunt capacitors
2. Switch in shunt inductors
3. Request that machine excitation be decreased to decrease the reactive power output
4. Adjust load tap changing (LTC) transformer tap positions
5. Reschedule pumped hydro units to pump
6. Adjust SVC output
7. Start fast response units with reactive power absorption capability
8. Switch out lines, as a last resort, without dropping load or generation

NYISO Actions – Low-Voltage Conditions

The NYISO shall request the TOs to perform the following normal steps to alleviate low voltage conditions:

1. Switch in shunt capacitors
2. Switch out shunt inductors
3. Request that machine excitation be increased to increase the reactive power output
4. Adjust load tap changing (LTC) transformer tap positions
5. Reschedule pumped hydro units to generate
6. Motor pumped hydro units to produce reactive power
7. Adjust SVC output
8. Start fast response units with reactive power export capability to help raise the system voltage
9. Switch in lines where available

Transmission Owners Actions – SVC Operation

Static Var Compensators (SVCs) are intended to be used for mitigating post-contingency voltage oscillations and voltage control when the power system is loaded close to the transfer limits. SVCs are not intended for steady state pre-contingency voltage support. The TO shall perform the following actions:

1. Maintain the SVC in the automatic mode and in the minimum output state within a deadband around zero reactive power output, under normal conditions.
2. Return the SVC to its minimum output state, after a disturbance has been cleared.
3. Coordinate the use of the SVC for bus voltage regulation with the NYISO and other affected TOs.

4.2.3 Guidelines for Leeds and Fraser SVCs to Control High Voltage

The guidelines for the operation of the Leeds and Fraser SVCs to control high voltage are given as follows:

1. General Requirements:

- The HQ/NY Import/Export on the Chateauguay – Massena 7040 line is at or below 1000 MW.
- Central – East and Total – East transfers are at or below transfer limits that assume the SVCs are unavailable.
- All appropriate switchable shunt capacitors have been taken out-of-service. All appropriate switchable inductors have been placed in-service.
- The maximum reactive capability of any Gilboa units or pumps currently in-service is being used. The effect of a Gilboa unit or pump to go in-service should be taken into account.
- The SVCs must be able to automatically respond to contingencies.

2. Specific Conditions to Use the Fraser SVC:

Subject to the above general requirements, the inductive capability of the Fraser SVC may be used to control high voltage in the area of the Marcy-South transmission lines subject to the following specific conditions:

- The capacitors at Marcy, Fraser, Coopers Corners, and Rock Tavern are out-of-service.
- The Marcy inductor is in-service.
- The capacitors at Gilboa should also be switched out-of-service, and any Gilboa units/pumps currently in-service should be absorbing maximum reactive power, provided that this does not cause unacceptably low voltage at Gilboa, New Scotland, or Leeds.
- The Oakdale 345 kV bus voltage is maintained above its pre-contingency low voltage limit.

3. Specific Conditions to Use the Leeds SVC:

Subject to the above general requirements, the inductive capability of the Leeds SVC may be used to control high voltage on the Eastern New York 345 kV Transmission System where it would be effective subject to the following specific conditions:

- The Marcy inductor is in-service.

The Fraser capacitors should be switched out-of-service, provided this does not cause unacceptably low voltage at Fraser, Oakdale, Marcy, Edic, or Coopers Corners.

4. Specific Conditions for the 7040 Line Out-of-Service:

Subject to the above requirements and conditions, the inductive capability of the Leeds and/or Fraser SVCs may be used to control high voltage when the 7040 line is out-of-service, with the additional provision that either both shunt reactors on the Massena-Marcy MSU-1 line are in-service, or the MSU-1 line is out-of-service.

4.2.4 Phase Angle Regulators Operations

Normal Operating Conditions

Under normal operating conditions, TOs shall determine power flows on PAR controlled lines and normally will implement PAR adjustments to avoid the need for generation redispatch if NYISO Secured transmission constraints can be mitigated by such adjustments. Significant schedule changes (100 MW or more) on inter-Control Area or inter-company tie lines shall be coordinated with the NYISO. However, small changes of 1 or 2 taps during changing load conditions, such as morning load pickup or evening load drop, that are within operating guidelines on inter-Control Area or inter-company ties may be coordinated between the affected companies.

The maximum loading of overhead lines controlled by PARs shall be the lesser of the normal rating or a level such that the post-contingency flow will not exceed its LTE rating. The post-contingency loading of any underground cable may exceed its LTE rating, but not its STE rating, provided 10-minute reserve or phase angle control is available to return its

post-contingency loading to its LTE rating within 15 minutes without causing another facility to be loaded beyond its LTE rating.

Power flows on PAR controlled lines that are within a TO's system shall be monitored and controlled by that TO. Power flows on other PAR controlled lines shall be monitored by the NYISO and appropriate action shall be coordinated with the TOs.

The following PAR actions apply to normal conditions.

NYISO Actions

The NYISO shall perform the following actions:

1. Coordinate the operation of the PARs that affect the transfer of power between the NYCA and adjacent Control Areas.
2. Request the TOs and adjacent Control Areas to adjust PAR taps.

Transmission Owner Actions

Transmission Owners shall perform the following actions:

1. Set the PAR taps and normally implement PAR adjustments to avoid the need for generation redispatch if NYISO-secured transmission constraints can be mitigated by such PAR adjustments.

4.2.5 Phase Angle Regulators – Con Ed/PSE&G Systems

Con Edison and PSE&G are interconnected at several locations with the following Phase Angle Regulators (PARs) to control the transfer of power over the circuits connecting the two companies:

1. A 345 kV phase angle regulating transformer with a range of ± 25° installed at the Con Edison Goethals substation.
2. Two 345 kV phase angle regulating transformers each with a range of ± 30°, installed at the Con Edison Farragut substation.
3. A 230 kV phase angle regulating transformer with a range of ± 25°, installed in the Waldwick-Hillsdale-New Milford Circuit located at the PSE&G Waldwick Switching Station.
4. A 230 kV phase angle regulating transformer with a range of ± 25°, installed in the Waldwick-Fair Lawn Circuit located at the PSE&G Waldwick Switching Station.
5. A 230 kV phase angle regulating transformer with a range of ± 25°, installed in the Waldwick-Hawthorne Circuit located at the PSE&G Waldwick Switching Station.

A FERC approved Operating Protocol (NYISO Market Service Tariff Attachment M-1) has been developed that is used by the NYISO and the Pennsylvania, New Jersey, Maryland Interconnection (PJM) in preparing to operate, and operating in real-time, the hourly flow of energy over the Consolidated Edison (ConEd) and Public Service Electric & Gas Company (PSEG) interconnections.

4.2.6 Implementing Special Multiple Contingencies

The SCUC and RTC/RTD programs normally incorporate the contingencies that are applicable to the power system as it is being operated. These procedures apply to special operating conditions when additional contingencies are required due to certain maintenance outage conditions.

NYISO Actions

The NYISO shall perform the following actions:

1. Validate the need for special multiple contingencies and request the TOs to submit the required information as defined.
2. Following notification by the TO to the NYISO Outage Scheduling Department and Transmission System Operator, the NYISO will implement the special multiple contingency for the Day-Ahead and Real-Time Market operation.

Transmission Owner Actions

The TO shall perform the following actions:

1. Notify the NYISO and request the need for monitoring of special contingencies.
2. Supply a description of the special operating maintenance condition, a list of the components making up the multiple contingency, the limiting element(s) the date/time to initiate the monitoring and the date/time to terminate the monitoring.
3. Observe the following lead times to implement such a contingency:
   - ✧ The necessary data must be provided to the NYISO Outage Scheduling Department at least by the morning of the previous working day, prior to the closing of the Day-Ahead Market.
   - ✧ Notification must be provided to the Transmission System Operator at least one hour in advance of the special operating condition.
4. Provide special contingency data when required and requested by the NYISO.

4.2.7 Security Violation Relief

When a security violation occurs or is anticipated to occur on the NYISO Secured Transmission System, the NYISO shall attempt to relieve the violation by using any one or more of the following procedures, typically in this order:

1. Reduce non-Firm Transmission Service.
2. Curtail non-Firm Transmission Service.
3. Re-dispatch internal Generators, based on Incremental and Decremental Bids.
4. Adjust the NYCA's DNI by manually curtailing Firm Transmission Service associated with Transactions supplied by External Generators. The NYISO shall decide which Transmission Service is to be curtailed based on the Decremental Bids in conjunction with NERC procedures, and shall curtail

Transmission Service until the transmission violation is relieved or all such Transmission Service has been curtailed.

5. Request Internal Generators to voluntarily operate in manual mode below minimum dispatchable levels.
6. Decommit Internal Generators based on their minimum generation Bid rate in descending order.
7. Attempt to purchase emergency energy from other control areas that will provide relief to the security violation.

4.2.8 Operating Under Adverse Conditions

The NYISO shall operate the NYISO secured transmission system during adverse conditions, including but not limited to peak load system conditions, thunderstorms alerts, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of LRRs and related PSC orders. Consistent with such Rules, the NYISO shall maintain reliability of the NYISO Secured Transmission System by directing the adjustment of the Generator output levels in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these adverse conditions, thereby reducing the likelihood of major power system disturbances.

The NYISO shall have the sole authority to declare that adverse conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the NYISO secured transmission system in response to those conditions. Activation of a procedure in compliance with a LRR shall involve a two step process. The TO, directly involved with such LRR, such as Storm Watch shall advise the NYISO that adverse conditions are imminent or present and recommend to the NYISO the activation of applicable procedures in support of that rule. Consistent with the LRR, the NYISO shall declare the activation of the appropriate procedures. The TO and the NYISO shall coordinate the implementation of the applicable procedures to the extent that NYISO secured transmission system facilities are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

Adjusted generation levels in response to activation of these procedures shall set the real time LBMPs. Revenue shortfalls may occur if the redispatch of the system curtails energy scheduled Day-Ahead and more expensive energy is dispatched subsequent to the Day-Ahead settlement. These revenue shortfalls shall be recovered through the NYISO's Scheduling, System Control, and Dispatch Service (Ancillary Service) charges.

4.2.9 Adverse Operating Conditions

NYISO Actions

The NYISO may perform the following actions under adverse operating conditions:

1. Notify all TOs and NPCC Control Areas.

2. Reduce RTC/RTD Stability Transfer Limits and RTC/RTD Central East Voltage Transfer Limits to 90% of the Stability Transfer Limit and Central East Voltage Transfer Limits where appropriate.
3. Reduce flows on inter-area and internal NYISO Secured Transmission System transmission lines to a maximum of 90% of the Normal Rating.
4. Cancel in-service relay and hot line work on A-1 transmission facilities. Recommend TO cancel in-service relay and hot line work on A-2 transmission facilities.
5. Restore out-of-service A-1 transmission facilities where possible. Recommend TO restore of out-of-service A-2 transmission facilities where possible.
6. Request TOs to implement appropriate emergency procedures when a contingency occurs.

Transmission Owner Actions

1. Implement NYISO requests to cancel in-service relay and hot line work on A-1 transmission facilities. Evaluate cancellation in-service relay and hot line work on A-2 transmission facilities.
2. Implement NYISO requests to restore out-of-service A-1 transmission facilities. Evaluate restoration of out-of-service A-2 transmission facilities.
3. Notify the NYISO of all actions taken related to this section.
4. Implement Emergency procedures, as requested by the NYISO.

4.2.10 Solar Magnetic Disturbances

Background

The sun emits streams of charged protons and electrons known as the solar wind. The intensity of the solar wind is determined by sunspot activities (solar flares, disappearing filaments, and coronal holes). The solar wind interacts with the earth's magnetic field producing auroral currents at altitudes of 100 kilometers that follow circular paths around the earth's geomagnetic poles. These non-uniform currents then cause time-varying fluctuations in the earth's magnetic field, which in turn induce a potential difference on the surface of the earth. This Earth-Surface Potential (ESP) is measured in volts per kilometer and its magnitude and direction are functions of the change in magnetic field, earth resistivity, and geographic latitude. ESP increases with increasing latitudes and its gradient is highest on facilities having an east-west orientation. ESP is highest in igneous rock areas. The resulting ESP appears as an ideal voltage source applied between grounded neutrals of wye-connected transformers in a power system, causing Geomagnetically Induced Current (GIC) to flow between grounded neutrals via transmission lines.

During a severe Solar Magnetic Disturbance (SMD), the quasi-dc ground induced current superimposed on the normal 60 Hertz power flow can result in half-cycle saturation of the cores of grounded, wye-connected power transformers. This over-excitation may cause the following power system problems:

1. Transformer overheating resulting in premature transformer failure

2. Increased system reactive losses resulting in the depletion of MVAr reserve
3. Decreased bus voltages resulting in a possible system voltage collapse
4. Increased 60 Hertz harmonics resulting in overheating and eventual tripping of static var compensators (SVCs) and shunt capacitors, protective relay misoperations, and interference with communication systems
5. Saturation of current transformers resulting in metering errors and relay misoperations
6. System voltage distortions resulting in improper operation of generator automatic voltage regulators and commutation failures in HVDC terminals and SVCs.

Monitoring

The NYISO receives SMD forecasts and alerts from three agencies:

1. Electronically, via the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (STD GSMS).
2. Space Environment Services Center (SESC) in Boulder, Colorado
3. Geographic Division, Geographical Survey of Canada, Energy, Mines, and Resources (EMR) in Ottawa, Canada via the Ontario Control Center.

An SMD forecast indicates that the condition is expected. An SMD alert indicates that the condition has occurred.

These agencies measure the disruption in the horizontal component of the earth's magnetic flux with magnometer. The STD GSMS is kept continuously up to date by Solar Weather Specialists located at www.spacew.com. SESC measures the geomagnetic activity in Boulder, Colorado and EMR measures the geomagnetic activity from 13 observatories in the Canadian Automatic Magnetic Observation System (AMOS). This information is quantified into A and K indices for forecasting and alerting purposes. The impact of an SMD on the power system increases with the intensity of the storm.

Information pertaining to Solar Magnetic Disturbances and the level of the disturbance will be disseminated by means of the STD GSMS.

SMD Forecasts

STD through the GSMS allows for continuous updating on current Solar Magnetic Disturbance activity, as well as 24-, 48- and 72-hour predictions on SMD activity. Currently, the STD uses a Kp Index, but does not specify by level what Forecast or an Alert is issued, merely they are issued depending on the activity seen by their satellite in regards to predicted SMD activity vs. actual observed SMD activity.

SESC (Boulder) issues forecasts in the form of a daily "A" index for up to three days in advance. The "A" index is a measure of the expected geomagnetic activity at Fredericksburg, Virginia. SESC (Boulder) transmits forecasts of the following two classifications of geomagnetic activity to the NYISO:

1. Minor Storm ("A" index 30-49)
2. Major Storm ("A" index above 50)

EMR (Ottawa) issues forecasts based on daily range predictions for up to three days in advance in the sub-auroral zone in which most of the NPCC Areas are located. Ontario and Hydro Quebec receive forecasts for the auroral zones separately. EMR (Ottawa) transmits forecasts of the following two classifications of geomagnetic activity to the NYISO:

1. Active Conditions (approximate "K" index of 5 or 6)
2. Major Storm Conditions (approximate "K" index of 7, 8 or 9)

SMD Alerts

STD through the GSMS allows for continuous updating on current Solar Magnetic Disturbance activity, as well as 24-, 48- and 72-hour predictions on SMD activity. Currently, the STD uses a Kp Index, but does not specify by level what Forecast or an Alert is issued, merely they are issued depending on the activity seen by their satellite in regards to predicted SMD activity vs. actual observed SMD activity.

SESC (Boulder) issues alerts in the form of a three-hour "K" index that is based on the average of the last three hours of disruption in the horizontal component of the earth's magnetic flux measured in Boulder, Colorado. SESC (Boulder) transmits alerts of the following classification of geomagnetic activity to the NYISO:

"K" index of K5 or greater

EMR (Ottawa) issues alerts based on a three hour average range index for the last three hours of disruption in the X (geographical northward) component of the earth's magnetic flux measured by the AMOS system. EMR (Ottawa) issues alerts for the following two classifications of geomagnetic activity to the NYISO:

1. Active Conditions (approximate "K" index of 5 or 6)
2. Major Storm Conditions (approximate "K" index of 7, 8 or 9)

All time references in SMD Forecasts and SMD Alerts received from SESC (Boulder) and EMR (Ottawa) are to Universal Time (which is the same as Greenwich Mean Time), a constant scientific time reference. Eastern Standard Time lags Universal Time by 5 hours. The NYISO converts all time references to prevailing Eastern Time (Standard Time or Daylight Saving Time) as shown in Table 4.2.

Table 4.2 Conversion from Universal Time

If the prevailing Eastern time is:	Then 0600 UTC (GMT) converts to:
Standard Time	0100 EST
Daylight Savings Time	0200 EDT

No NYISO actions are required if:

- SMD Forecast of an A-index is equal to or less than 29 and
- SMD Alert is equal to K4 or less

Minor storm active conditions exist when:

- A-index is greater 29 but less than or equal to 50 and
- Alert is greater than K4 but less than or equal to K6

NYISO Actions

The NYISO shall perform the following actions:

1. Upon notification of an SMD Forecast of an A-index greater than 50 or an SMD Alert of K6 or greater, record the information in the control room log .
2. Notify all TOs and NPCC Control Areas.
   (i) TOs will notify generators within their areas.
3. If an Alert of K7 or greater has been issued on the STD with significant GIC (Ground Induced Currents) activity observed by a neighboring Control Area or a Transmission Owner, the NYSIO shall initiate the following actions:

Declare Alert State

1. Notify TOs to reduce normal limits on inter-area and internal NYS Power System transmission lines and transformers to a maximum of 90% of the normal rating where appropriate.
2. Request generators (via their TOs) to adjust machine excitation, to maintain the NYISO Secured Transmission System voltages within acceptable operating ranges to protect against voltage swings.
3. Reduce RTC/RTD Stability Transfer Limits and RTC/RTD Central East Voltage Contingency Limits to 90% of the Stability Transfer Limit and Central East Voltage Contingency Limits where appropriate.
4. Request TOs to implement appropriate emergency procedures, when a contingency occurs.
5. Reduce flows on inter-area and internal NYISO Secured Transmission System transmission lines to a maximum of 90% of the Normal Rating.
6. Activate Thunder Storm Warning cases (TSW) when an alert of K9 has been issued and significant GIC activity has been observed.

Transmission Owner Actions

TOs shall perform the following actions upon notification of an SMD Alert of a Major Storm Condition (K7-K9) or prior to the forecasted arrival of the storm upon notification of an SMD Forecast of a Major Storm Condition (K7-K9):

1. Restore out-of-service transmission facilities, where possible, and avoid taking long transmission lines out of service.
2. Review all in-service work, evaluate the impact of the loss of these facilities on the NYISO Secured Transmission System, and cancel in-service work on critical facilities.
3. Monitor the MVAr and voltage displays on their SCADA systems for unusual voltage and/or MVAr variations.
4. Keep area substation capacitor banks in service, where possible, and evaluate the impact of the loss of transmission shunt capacitor banks.
5. Notify the NYISO of all actions taken related to this section.

Implement Emergency procedures, as requested by the NYISO.

4.2.11 Status of Transmission and Generation Protection Systems

Background

NERC reliability standards require the NYISO to be cognizant of the status of transmission and generation special protection systems affecting the New York bulk power system.

Details

In order to assist the NYISO in performing its responsibilities as a Reliability Coordinator, Transmission and Generation Owners and Operators in the NYISO Reliability Coordination Area are required to perform the following:

1. ***Coordination.*** Coordinate protection systems and changes in generation, transmission, load, or operating conditions that could require changes in the protection systems of others. This coordination shall take place between the affected facility owners.
2. ***Operational Status.*** Notify the NYISO of changes in the operational status of all Special Protection Systems. This reporting will be to the NYISO Grid Operations Shift Supervisor via the affected Transmission Owner's control center. NYISO will notify neighboring Balancing Authorities as noted in the New York Protection Memos.
3. ***Failures.*** Notify the NYISO of relay or protective system operational failures which reduce system reliability. Failures should be reported immediately to the NYISO Grid Operations Shift Supervisor via the affected Transmission Owner's control center. NYISO will notify neighboring Balancing Authorities as noted in the New York Protection Memos.

References for this Section 4.2.11:

NPCC Directory D1, "Design and Operation of the BPS," December 15,2009, or latest issue.

NERC Reliability Standard PRC-001-1, "System Protection Coordination," effective January 1, 2007, or latest issue.

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5. SCHEDULING OPERATIONS

This section describes the Dispatch Day scheduling process, covering the following:

- Real-Time Commitment
- Scheduling Operations Requirements
- Scheduling Operations Procedures
- Supplemental Resource Evaluation Procedures

5.1 Real-Time Commitment

Real-Time Commitment (RTC) is a multi-period security constrained unit commitment and dispatch process that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least as-bid production cost basis over a two-hour and fifteen-minute optimization period. The optimization evaluates the next ten points in time separated by fifteen-minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; "RTC_{00}," RTC_{15}," RTC_{30}," and RTC_{45}" post on the hour, and at fifteen, thirty, and forty-five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning at fifteen and thirty minutes after its scheduled posting time, and will produce advisory commitment guidance for the remainder of the optimization period. RTC_{15} will also establish External Transaction schedules for hourly transactions. Figure 5-1 presents the timeline for RTC_{15}.

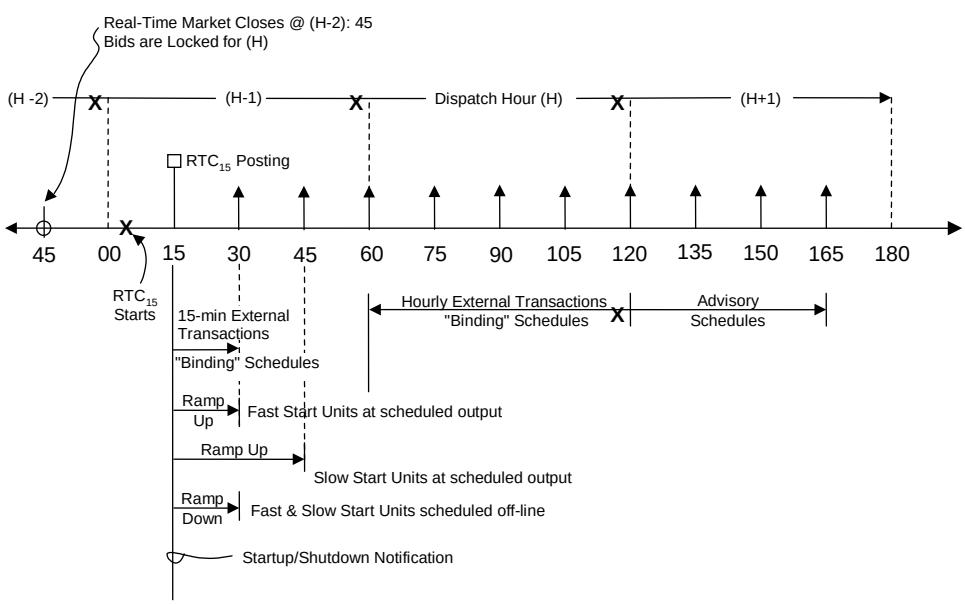

Figure 5-1 RTC15 Time Line

5.1.1 Real-Time Commitment Process

RTC will make binding unit commitment and de-commitment decisions for the periods beginning fifteen minutes (in the case of Resources that can respond in ten minutes) and thirty minutes (in the case of Resources that can respond in thirty minutes) after the scheduled posting time of each RTC run, will provide advisory commitment information for the remainder of the two and a half hour optimization period, and will produce binding schedules for External Transactions to begin at the start of each quarter hour. RTC will co-optimize to solve simultaneously for all Load, Operating Reserves and Regulation Service requirements and to minimize the total as-bid production costs over its optimization timeframe. RTC will consider SCUC's Resource commitment for the day, load forecasts from the load forecasting program and loss forecasts that RTC itself will produce each quarter hour, binding transmission constraints, and all Real-Time Bids and Bid parameters.

Initialization Status

RTC honors all day-ahead commitments of internal generation resulting from SCUC, except for 10 and 30 minute start gas turbines. The unit statuses at the time of initialization are based on the current operating mode at the time of initialization, modified to include projected changes from the previous quarter hour's evaluation.

Startup Time

RTC can commit units with a startup time of 30 minutes or less. For instance, units that submit a 30-minute startup time will receive a binding startup notification from the RTC that posts its results 30 minutes before the scheduled start of the unit. Units that submit a 10 to 15-minute startup time will receive a binding startup notification from the RTC that posts its results 15 minutes before the scheduled start of the unit.

Minimum Down Time

The minimum down time is honored by RTC unless a unit has a Day-Ahead Market commitment included as part of the 2 ½ hour RTC evaluation window. In this situation, RTC will automatically reset the bid minimum down time parameter at the start of its evaluation to honor the Day-Ahead commitment.

Minimum Run Time

The minimum run time values allowed in RTC can be as little as 15 minutes. The longest Minimum Run Time allowed for generators that are economically committed by RTC in the Real-Time Market shall be one hour, unless the generator is a Real-Time Minimum Run Qualified Gas Turbine. For Real-Time Minimum Run Qualified Gas Turbines, the Minimum Run Time assigned by RTC for economic commitment shall be two hours.

In addition, a Real-Time Minimum Run Qualified Gas Turbine HAM bid shall be subject to restricted updates up to 135 minutes prior to the dispatch hour. These restrictions prevent a Real-Time Minimum Run Qualified Gas Turbine from increasing the cost of any *Validation Passed* HAM bid or deleting any *Validation Passed* HAM bid if the update is attempted within 135 minutes of the dispatch hour.

Qualification for a Real-Time Minimum Run Qualified Gas Turbine

Market Participant must first qualify its unit(s) with the NYISO by submitting a completed Real-Time Minimum Run Qualified registration form. This form can be found on the NYISO web-site under Services/NYISO Registration.

The Real-Time Minimum Run qualification is intended to more appropriately represent the physical operating characteristics of a combined cycle unit. Characteristics that qualify combined cycle units for this treatment include using waste heat from the gas turbine exhaust to make steam for the generation of additional electricity via a steam turbine.

All bidding points of a Generator must qualify if that Generator is to qualify for Real-Time Minimum Run treatment. See the definition of Generator in the Market Services Tariff. If the unit is approved, the Real-Time Minimum Run Qualified parameter will be applied by NYISO Customer Relations in the NYISO Market Information System (MIS).

Real-Time Bids to Supply Energy and Ancillary Services

After the Day-Ahead schedule is published and no later than 75 minutes before each hour, Customers may submit Real-Time Bids into RTC for real-time evaluation. Eligible Customers may submit new or revised Bids to supply Energy, Operating Reserves and/or Regulation Service. Customers that submit such Bids may specify different Bid parameters in RTC than they did Day-Ahead. Incremental Energy Bids may be submitted by Suppliers bidding Resources using ISO-Committed Fixed, ISO-Committed Flexible, and Self-Committed Flexible bid modes that exceed the Incremental Energy Bids submitted in the Day-Ahead Market or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited. Minimum Generation Bids and Start-Up Bids for any hour in which such Resources received a Day-Ahead Energy schedule may not exceed the Minimum Generation Bids and Start-up Bids submitted for those Resources in the Day-Ahead Market. Additionally, Real-Time Minimum Run Qualified Gas Turbine Customers shall not increase their previously submitted Real-Time Incremental Energy Bids, Minimum Generation Bids, or Start-Up Bids within 135 minutes of the dispatch hour. Bids to supply Energy or Ancillary Services shall be subject to the rules set forth in the *NYISO Ancillary Services Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

Generators that did not submit a Day-Ahead Bid for a given hour may offer to be NYISO-Committed Flexible, Self-Committed Flexible, or Self-Committed Fixed in real-time or ISO-Committed Fixed (with ISO approval). Generators that submitted a Day-Ahead Bid but did not receive a Day-Ahead schedule for a given hour may change their bidding mode for that hour in real-time without restriction except for ISO-Committed Fixed which requires ISO approval. Generators that received a Day-Ahead schedule for a given hour may change their bidding mode between Day-Ahead and real-time subject to the following restrictions:

1. Generators that were scheduled Day-Ahead in NYISO-Committed Flexible mode may not switch to NYISO-Committed Fixed or Self-Committed Fixed mode unless a real-time physical operating problem makes it impossible for them to bid in any other mode.

2. Generators that were scheduled Day-Ahead in Self-Committed Flexible mode may not switch to NYISO-Committed Fixed or NYISO-Committed Flexible mode and may only switch to Self-Committed Fixed mode if a real-time physical operating problem makes it impossible for them to bid in any other mode.
3. Generators that were scheduled Day-Ahead in NYISO-Committed Fixed mode must be in Self-Committed Fixed mode in real-time unless ISO approves a request to operate in ISO-Committed Fixed mode in real-time.
4. Generators that were scheduled Day-Ahead in Self-Committed Fixed mode may not switch to a different bidding mode in real-time except that they can switch to ISO-Committed Fixed mode in real-time with ISO approval.

Generators may not submit separate Operating Reserves Availability Bids in real-time and will instead automatically be assigned a real-time Operating Reserves Availability Bid of zero for the amount of Operating Reserves they are capable of providing in light of their response rate (as determined under Rate Schedule 4 of the Services Tariff, available from the NYISO Web site at the following URL: http://www.nyiso.com/public/documents/tariffs/market_services.jsp.

Dispatch Options for 10-Minute Start and 30-Minute Start Generators

For units that can only operate at a single fixed point (on or off, historically GTs), special modeling has been done to allow these units to participate in setting the LBMP, when marginal, and included in the idealized dispatch by RTC and RTD/RTD-CAM if the unit can pass the qualifications. Units that desire to operate in this fashion will have their bid options limited to a model that SCUC, RTC, and RTD/RTD-CAM can support.

Any unit that qualifies as a 10-Minute Start Generator can then participate in the idealized dispatch performed in real time by RTC and RTD-CAM. These units will receive forward commitments from SCUC and may be committed by RTC just like any other unit. These units may also be committed by RTD-CAM when needed in real time. When started, they will be ramped to their upper operating limit and will be used in setting the LBMP when they are the marginal unit in the idealized dispatch.

Any unit that can be started within 30 minutes has the option of being qualified as a 30-Minute Start Generator. These units may receive forward commitments from SCUC and may be committed by RTC and scheduled at a fixed operating point in real time just like a unit that can operate over a range of values. These units may also be committed by RTD-CAM operating in maximum gen pickup mode. These units will be used in setting the LBMP when they are the marginal unit in the idealized dispatch.

10-Minute Start Generators

Units utilizing this flexibility to participate in the markets need to be aware of the bidding requirements placed on them when deciding to qualify a unit in this fashion. Because of the special modeling requirements in Real-Time Commitment (RTC) and Real-Time Dispatch (RTD)/Real-Time Dispatch-Corrective Action Mode (RTD-CAM) for 10-minute start units, units that are qualified for this option will need to coordinate with the NYISO if they wish to be treated as a 10-minute start generator.

A unit that is designated as a 10-minute start unit will be considered Flexible in real time, but Off-Line until either RTC or RTD-CAM dispatches the unit. When RTC/RTD-CAM decides the unit should be started, the unit will be turned on and ramped over a nominal 10-minute interval to the upper operating limit. The unit will remain on for as long as needed or for a minimum period. Because RTD-CAM is making an instantaneous decision on starting the unit versus looking at the need for the unit over some longer time period, the NYISO has set and will guarantee the minimum run time for one hour. 10-minute start units will also be allowed to bid a start up and energy price in the Day-Ahead Market.

Requirements:

- Pre-qualified as 10-Minute Generator
- Check Flexible in Real Time
- Start-up time = 0 minutes
- Start-up cost = per bidder in DAM
- Minimum Generation level = 0 MWs
- Minimum Generation cost = $0.00
- Minimum Run Time <= 1 hour

Units have the flexibility to bid start-up costs on an hourly basis, for each hour of the day, or by a curve that relates the start-up cost to the elapsed time since shutdown. Hourly startup costs, if bid, take precedence over the startup cost versus hours off-line curve.

All programs determine if the unit is a marginal unit, where the desired operating point would be between zero and the upper limit, and allow the unit to set the LBMP. The programs then pin the unit to its upper limit and re-dispatch the system. All bids are passed to RTC and RTD/RTD-CAM regardless of whether they are actually scheduled by SCUC.

In addition to energy, 10-minute start generators can bid only 10-minute non-synchronous reserve. 10-minute start units may not bid the other types of reserve or regulation.

30-Minute Generators

Generators utilizing this flexibility to participate in the markets need to be aware of the bidding requirements placed on them when deciding to qualify a unit in this fashion. Because of the special modeling requirements in RTC/RTD-CAM for 30-Minute Generators, units that may qualify for this option will need to coordinate with the NYISO on how they would like to be treated.

A unit that is designated as a 30-Minute Generator will only be scheduled by RTD or RTD-CAM if it has been selected by RTC or RTD-CAM (operating in the max gen pickup mode). The difference between a normal fixed unit bid and a 30-minute generator is the 30-minute generator provides a dispatch bid for RTD or RTD-CAM to determine if the unit is marginal in an idealized dispatch and thus set the LBMP. The unit will remain on for as long as RTC or RTD-CAM (operating in the max gen pickup mode) has committed the unit.

Requirements:

- Pre-qualified as 30-Minute Generator

- Check ISO-Committed Flexible in Real Time
- Start-up time <= 30 minutes
- Start-up cost = per bidder
- Minimum Generation level = 0 MWs
- Minimum Generation cost = $0.00

As with 10-minute start units, these units will be evaluated based on the bid curve between zero and upper operating limit. SCUC, RTC, RTD and RTD-CAM determine if the unit is a marginal unit in the idealized dispatch, where its operating point would be between zero and the upper limit, and, if so, allow the unit to set the LBMP. They then pin the unit to its upper limit, re-dispatch the system, and send the unit a base point equal to its upper limit. Only RTC-scheduled units are passed to RTD.

15 Minute Scheduling of Internal Generation

NYISO qualified non-flexible generators have an option in the Real-Time Market to bid economically using the *ISO-Committed Fixed* mode. Market Participants using this option must convert to *ISO-Committed Fixed* their Day-Ahead Market bids (if any), that have rolled into the Real-time Market in the default *Self-Committed Fixed* mode. These bids will be evaluated by RTC so its schedule will better follow Real-Time energy prices. If these bids are accepted they will receive a market-based schedule that is fixed for each 15-minute segment of the hour and will be honored in RTD.

Generator Qualification

A Market Participant must first qualify its unit(s) with the NYISO via its Customer Representative.

15-minute scheduling is intended to provide economic scheduling opportunities for units that are currently operating at pre-specified fixed output schedules. Qualification for 15-minute scheduling includes, but is not limited to, having submitted 100% of available bid opportunities as either Self- Committed-Fixed, or ISO Committed-Fixed, in the Day-Ahead Market (which converts to Self-Committed Fixed in real-time) for a period of at least six (6) contiguous months.

Generators that do not have the communications systems, operational control mechanisms or hardware to be able to respond to five-minute dispatch basepoints may also be eligible for 15 minute scheduling.

Temporary equipment problems affecting Generators that do not meet the above standards do not make them eligible for 15-minute scheduling.

If the unit is approved, its 15-minute scheduling parameter, also known as a “qualified-to-bid” flag, will be set to Y (Yes) by the Customer Representative in the NYISO Market Information System (MIS). The term used for such approved and flagged units are “15-minute generators/units.”

Bidding and Scheduling Rules

It follows from the qualification constraints mentioned above that for **both** the Day-Ahead (DAM) and Real-Time (RT) Markets, 15-minute generators must submit **either** *ISO-*

Committed Fixed or *Self-Committed Fixed* bids. In the RT Market these units may still self-schedule in 15-minute blocks using the *Self-Committed Fixed* mode, but to be scheduled economically by the NYISO they must bid in, and be accepted, as *ISO-Committed Fixed*. Again, *ISO-Committed Flexible* and *Self-Committed Flexible* bids will **not** pass MIS bid validation in either market for 15-minute units. No DAM schedule is necessary to bid in the RT Market for 15-minute generators. The table below summarizes the allowed combinations of DAM and subsequent RT bids:

Day-Ahead Mkt 15m gens.	**Real-Time Market - 15-minute generators**			
	ISO-Committed Flexible	Self-Committed Flexible	Self-Committed Fixed	ISO-Committed Fixed (15 minute qualified)
ISO-Committed Fixed	No	No	Yes	Yes - see Note below
Self-Committed Fixed	No	No	Yes	Yes - see Note below
15m units with No Day-Ahead Schedule	No	No	Yes	Yes

Note:
Upon posting of the Day-Ahead market, the Day-Ahead schedule for each 15-minute generator (like other fixed generators) is used to pre-populate (initialize) its Real-Time bids in the *Self-Committed Fixed* mode, no matter which of the two *fixed* modes is used in the DAM.
Therefore:
If a 15-minute generator with a DAM schedule intends to bid in RT as *ISO-Committed Fixed*, it **must**, for each hour desired, convert its *Self-Committed Fixed* RT bids in the MIS using the radio buttons in the "Unit Operations" box on the Generator Bid screen. Initial bids and bid modifications may be entered in the MIS through the upload process.

Consistent with all RT bidding rules, this may be done from when the DAM schedule has posted until 75 minutes before the operating hour.

This conversion option is available only to 15-minute generators and will be subject to the standard RT Market validation rules for adjusting DAM bids that have rolled into the RT market:

1. The Minimum Generation MW must be equal to bid Min Gen MW from the accepted DAM bid.
2. The Upper Operating Limit-Normal (UOLn) must be greater than or equal to the UOLn from the accepted DAM bid.
3. The UOLn must be greater than or equal to the sum of DAM accepted energy, reserves,and regulation schedules.
4. The Upper Operating Limit-Emergency (UOLe) must be greater than or equal to the sum of the DAM accepted energy, reserves, and regulation schedules.
5. Incremental Energy Bids may exceed the Incremental Energy Bids submitted in the Day-Ahead Market, or the mitigated Day-Ahead Incremental Energy Bids where appropriate, for portions of the Capacity of such Resources that were scheduled in the Day-Ahead Market, if not otherwise prohibited.
6. Real-Time Minimum Run Qualified Gas Turbine Customers must submit increased bids at least 135 minutes before the dispatch hour.
7. The RT Startup Cost must be less than or equal to the accepted DAM bid startup cost.

8. The RT bid Minimum Generation Dollars must be less than or equal to the accepted DAM bid minimum generation cost.
9. RT bids must not have any dollar value, including $0, in the reserve or regulation fields. Only null dollar amounts are acceptable. In other words, no reserve or regulation will be awarded to 15-minute scheduled units.

> ***Note:*** Please see the Market Participant User's Guide, Section 6, for bid rules on generator operating modes for those units **not** qualified to bid 15-minute scheduling.

Bids Associated with Internal and External Transactions

Customers may seek to modify Transactions that were previously scheduled Day-Ahead or propose new Transactions, including External Transactions, for economic evaluation by RTC. Bids associated with Internal Bilateral Transactions shall be subject to the rules set forth in this Manual.

Sink Price Cap Bids, Decremental Bids and CTS Interface Bids to schedule External Transactions may be submitted into RTC up to 75 minutes before the hour in which the External Transaction would flow. External Transaction Bids must cover a one-hour period and must start and stop on the hour. Intra-hour modifications to External Transaction Bids will not be accommodated. Schedules associated with External Transactions will be established based on the schedule type indicated on the submitted bid (Hourly vs Intra-hour), as well as on the scheduling frequency supported by the associated Proxy Generator Buses, as outlined in the tariff.

Internal Bilateral Transactions involving Trading Hubs must be part of a balanced set for the Trading Hub Energy Owner by the time the respective market closes. In order for a Trading Hub Energy Owner to have a balanced set, that Trading Hub Energy Owner must source the same amount of megawatts as it sinks at that zonal Trading Hub in a given market and hour. If an Internal Bilateral Transaction involving a Trading Hub is not part of a balanced set, it will not be scheduled.

Self-Commitment Requests

Self-Committed Flexible Resources must provide the NYISO with schedules of their expected minimum operating points in quarter hour increments. Self-Committed Fixed Resources must provide their expected actual operating points in quarter hour increments.

External Transaction Scheduling

RTC will schedule External Transactions based on the schedule type indicated on the submitted bid (Hourly vs Intra-hour), as well as on the scheduling frequency supported by the associated Proxy Generator Buses, as outlined in the tariff. RTC_{15} will establish binding schedules for hourly transactions for the next hour and each RTC run will establish binding schedules for intra-hour transactions for the period beginning fifteen minutes after the scheduled posting time of each RTC run as part of its development of a co-optimized least-bid cost real-time commitment. The RTC evaluation includes a limitation for top-of-the-hour scheduling changes. The change at the top of the hour is limited to 700 MWs for the NYCA interchange to maintain system reliability.

Posting Commitment/De-Commitment and External Transaction Scheduling Decisions

RTC will also produce advisory commitment information and advisory real-time prices. RTC will make decisions and post information in a series of fifteen-minute "runs" which are described below.

RTC_{15}

RTC_{15} will begin at the start of the first hour of the RTC co-optimization period and will post its commitment, de-commitment, and External Transaction scheduling decisions no later than fifteen minutes after the start of that hour. During the RTC_{15} run, RTC will:

1. Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at their minimum generation levels by that time.
2. Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at their minimum generation levels by that time.
3. De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected by that time.
4. Issue advisory commitment and de-commitment guidance for periods more than thirty minutes in the future and advisory dispatch information.
5. Schedule economic hourly External Transactions to run during the entirety of the next hour.
6. Schedule economic 15-minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus.
7. Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at a CTS Enabled Proxy Generator Bus; and
8. Issue real-time schedules for resources in ISO-Committed Fixed mode.

Subsequent RTC Runs

All subsequent RTC runs in the hour, i.e., RTC_{30}, RTC_{45}, and RTC_{00} will begin executing at fifteen minutes before their designated posting times (for example, RTC_{30} will begin in the 15th minute of the hour), and will take the following steps:

1. Commit Resources with 10-minute start-up times that should be synchronized by the time that the results of the next RTC run are posted so that they will be synchronized and running at that time.
2. Commit Resources with 30-minute start-up times that should be synchronized by the time that the results of the RTC run following the next RTC run are posted so that they will be synchronized and running at that time.

3. De-commit Resources that should be disconnected from the network by the time that the results of the next RTC run are posted so that they will be disconnected at that time.
4. Issue advisory commitment, de-commitment, and dispatching guidance for the period from 30 minutes in the future until the end of the RTC co-optimization period.
5. Either reaffirm that the hourly External Transactions scheduled by RTC_{15} to flow in the next hour should flow, or inform the NYISO that hourly External Transactions may need to be reduced.
6. Schedule economic 15-minute External Transactions , for the quarter hour for which the results of the next RTC run are posted, at Variably Scheduled Proxy Generator Buses other than a CTS Enabled Proxy Generator Bus.
7. Schedule economic 15 minute External Transactions, for the quarter hour for which the results of the next RTC run are posted, at CTS Enabled Proxy Generator Buses; and
8. Issue real-time schedules for resources in ISO-Committed Fixed mode.

External Transaction Settlements

RTC will calculate the External Interface Congestion component of the Real-Time LBMP for all External Transactions if constraints at the interface associated with that External Transaction are binding. In addition, RTC will calculate the External Interface Congestion component of the Real-Time LBMPs at Proxy Generator Buses for any hour in which:

1. Proposed economic Transactions over the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed the Available Transfer Capability for that Interface.
2. Proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole.
3. Proposed interchange schedule changes pertaining to the Interface between the NYCA and the External Control Area that the Proxy Generator Bus is associated with would exceed any Ramp Capacity limit imposed by the NYISO for that Interface.

Finally, RTC will also calculate the External Interface Congestion component of the Real-Time LBMPs at certain times at Non-Competitive Proxy Generator Buses.

1. Any External Interface Congestion calculated by RTC will be added to the Marginal Cost of Internal Congestion calculated by RTD to determine the total Marginal Cost of Congestion that will be reflected in the RTD LBMP at a Proxy Generator Bus that is not a Non-Competitive Proxy Generator Bus or a Proxy Generator Buses associated with a designated Scheduled Line. Additional detail regarding the calculation of real-time prices at Proxy Generator Buses appears in Section 17.1.6 of the Services Tariff.

5.1.2 Real-Time Automated Mitigation Process

The real-time automated mitigation process (RT-AMP) incorporates both conduct tests (performed in the MIS) and impact tests (performed in RTC-AMP sequence). The conduct test compares the price of each energy offer, including start-up and minimum generation costs, to references. When reference prices have been exceeded by an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff, available from the NYISO Web site at the following URL: http://www.nyiso.com/public/documents/tariffs/market_services.jsp), the conduct test is said to have "tripped."

The AMP LBMP impact test examines the change in prices that would prevail if conduct-failing offer prices were mitigated. This test "trips" if mitigation of conduct-failing offers would change prices by an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff. A variation of the first impact test applies to designated "Constrained Areas" when the transmission system is congested and "trips" if the change in LBMP exceeds an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff. This first impact test will be performed following a full recommitment and dispatch.

There are many rules, parameters, limits, and thresholds that have been defined associated with the automated mitigation process. These include:

1. Definition of super-zones in the NYCA and load pockets in constrained areas.
2. Definition of a threshold values for each load pocket of a constrained area.
3. Arming the automated mitigation process.
4. Portfolio exclusion that may be applied to super-zones and load pockets.
5. Definition of the specific units subject to the automated mitigation process.

RT-AMP Process

Automated mitigation relies on a second unit commitment evaluation to assess the impact of mitigation. Thus, two unit commitment executions are required at each time step. The first determines the prices and schedules that would occur with the original set (Base-Set) of offers. The second determines the prices and schedules that would occur with a mitigated set (Ref-Set) of offers. The combined execution times of the unit commitments needed to evaluate both Base-Set and Ref-Set is likely longer than the RTC interval (15 minutes). However, each commitment is executed as a separate process so they can be run in parallel as shown in figure Figure 5-2. The advantage is that a full RTC cycle (15 minutes) can be used to evaluate impact; hence, timing concerns are minimized. The possibility of mitigation is tested for the next RTC cycle (15 minutes) in the future. RTC_{15} and $RT\text{-}AMP_{15}$ perform unit commitment evaluations simultaneously. Results of RTC_{15} and $RT\text{-}AMP_{15}$ are then evaluated for impact and, if mitigation is necessary, mitigated offers are sent to RTC_{30}. Mitigation of offers for RTC_{15} (if any) was determined previously by $RT\text{-}AMP_{00}$.

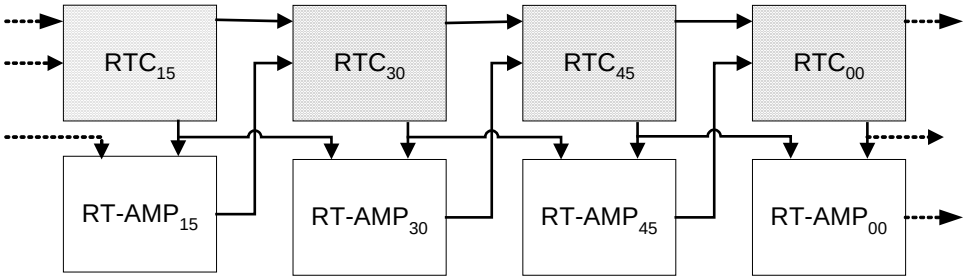

Figure 5-2 RTC_{15} Time Line

A third unit commitment is required to assure that prices and schedules are consistent with the final set of offers, some of which may be mitigated. Because the test is conducted in parallel, only one, instead of two, additional unit commitment is required in each RTC cycle. As shown in Figure 5-3, for the time period 15 to 30, Base-Set and Mit-Set are identical. RTC_{15} provides the base case unit commitment. Simultaneously $RT\text{-}AMP_{15}$ calculates the reference unit commitment, conducts the impact test, and determines the actual set of resources whose offers are to be mitigated (Mit-Set). Finally, RTC_{30} ensures that the commitment is consistent with the set of mitigated offers. Subsequently the Mit-Set is used as the Base-Set and RTC_{30} would provide the base case for RT-AMP30.

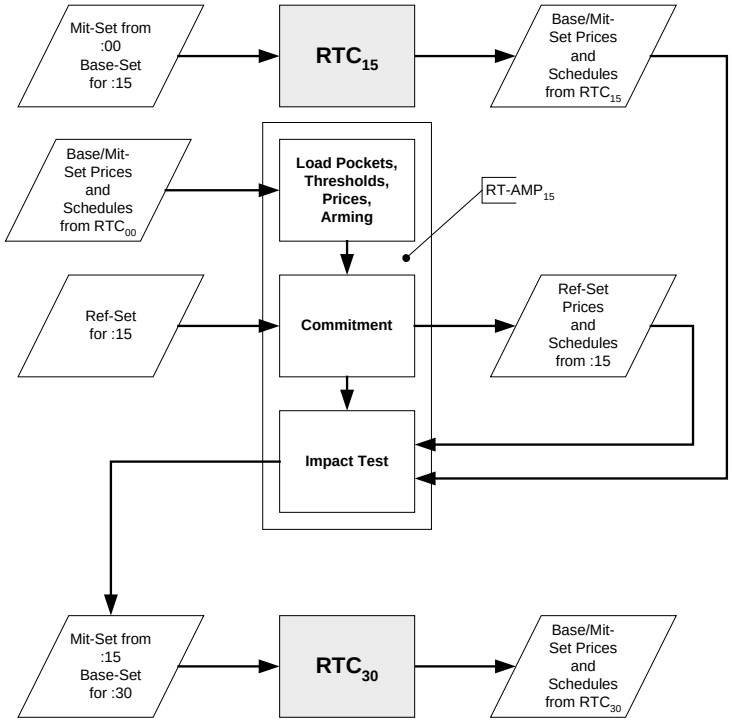

Figure 5-3 Parallel Impact Test 15 to 30 Minutes

Conduct Test

The conduct tests compare offers of suppliers for start-up, minimum generation, and incremental energy with reference levels for each of those bids. Differences are compared to the thresholds set forth in Attachment H of the NYISO Services Tariff to determine whether conduct suggests the possible economic withholding of resources or a possible attempt to exercise market power. A subsequent impact test determines if conduct-failing bids (or bid components) had the requisite market impact, and should be mitigated.

An energy resource may be associated with several load pockets, each of which has a threshold value. In such a case, conduct is tested using the threshold value(s) for all load pockets in which the resource is located. The arming test later selects the appropriate conduct test results to use to determine if mitigation is appropriate.

Arming

The arming test makes an initial determination of whether mitigation is likely to result in a material price impact. Subsequently the impact test verifies a material price impact, whether on LBMP or on a portion of the congestion component of LBMP.

Price Impact

The impact test compares prices (or local congestion) determined with two sets of offers:

1. An original set called the Base-Set and
2. A set resulting from the mitigation of offers tripping the conduct test (subject to the arming criteria), called the Ref-Set.

The price impact test is evaluated at each time interval. The test will trip for an interval if the difference in energy price (or local congestion) exceeds an amount specified by the Market Mitigation Measures (defined in Attachment H of the NYISO Services Tariff.

Mitigation Duration

For purposes of settlement, Mitigation is applied for whole hours, when impact is determined for any interval of that hour. For dispatch purposes, mitigation is applied for the remainder of the current hour and/or all of the next hour, following a determination of impact. For dispatch purposes both RT-AMP_{15} and RT-AMP_{30} are able to mitigate offers for all or part of 2 hours. RT-AMP_{45} is able to mitigate offers for the “next” hour. RT-AMP_{00} is able to mitigate offers for part of an hour. Mitigated offers are used by both RTC and RTD.

5.1.3 Real-Time Commitment Information Posting

The public information and secure Market Participant data to be posted from the execution of RTC is described in this subsection.

Public Information

The following information will be produced and posted by RTC:

1. Updated ATCs and TTCs for each hour.
2. Advisory prices for Zones and Generators.

Secure Data to Market Participant

The following information will be produced by RTC and will be made available to authorized MPs:

1. Economically Evaluated External Transaction MW schedules for the binding interval.
2. Advisory MW commitment schedules for generators for each RTC 15-minute increment beyond the time frame covered by RTD.

5.2 Scheduling Operations Requirements

This subsection describes the requirements for the Dispatch Day scheduling of generation, transactions, load, and Ancillary Services. The principal functions are:

- Dispatch Day Scheduling Changes
- Interchange Scheduling
- Scheduling and Curtailment of Bilateral Transactions
- Scheduling and Dispatching LBMP Suppliers and Loads
- Capacity Limited and Energy Limited Resources
- Inter-Control Area ICAP Energy
- Emergency Demand Response Program and Special Case Resources.

5.2.1 Dispatch Day Scheduling Changes

After the Day-Ahead schedule is published, the NYISO evaluates any events, including but not limited to the loss of significant Generators or transmission facilities that may cause the NYCA dispatch to be inadequate to meet the requirements established in the Reliability Rules. When a supplier on forced outage becomes available for service again, it may submit a new bid in the dispatch day for potential commitment by RTC or SRE or day ahead for potential commitment by SCUC.

The NYISO may augment, as necessary, the Day-Ahead commitment schedules to achieve a reliable next-day schedule by performing a Supplemental Resource Evaluation (SRE). The NYISO may use the following resources:

1. Bids submitted to the NYISO that were not previously accepted but were designated by the bidder as continuing to be available for emergency needs
2. New Bids from all Suppliers, including those in neighboring systems
3. Cancellation of/or rescheduling of transmission facility maintenance outages where RTC/RTD is not expected to solve security constraints.

Actions taken by the NYISO in performing Supplemental Resource Evaluation (SRE) will not change any financial commitments that resulted from the Day-Ahead SCUC. The procedures for supplemental resource evaluation for energy and ancillary services are covered in this Manual.

5.2.2 Interchange Scheduling

The Interchange Scheduling (IS+) function allows NYISO personnel to monitor ongoing energy transactions. These transactions are bids accepted in either the Day-Ahead scheduling process or the RTC scheduling/dispatch process. The IS+ program provides facilities for entering transactions and reviewing existing transaction information. The following basic calculations are performed:

1. ***Desired Net Interchange (DNI):*** This calculation provides the net interchange schedule between the NYCA and each of the External Control Areas.
2. ***Instantaneous ANI:*** This is the metered control area interchange between the NYCA and each of the External Control Areas.

DNIs that reflect scheduled energy interchanges between the NYCA and neighboring Control Areas will need to be coordinated and verified by neighboring Control Areas as specified in interconnection agreements between the NYISO and other Control Areas.

5.2.3 Scheduling and Curtailment of Bilateral Transactions

Bilateral transactions may be requested as Firm or Non-Firm. A Firm transaction is willing to pay congestion, so that an accepted Day-Ahead Firm transaction receives a forward commitment for its schedule and is charged a Transmission Usage Charge (TUC = Congestion Price + Incremental Losses). A Non-Firm transaction is unwilling to pay congestion, so its schedule is advisory only and subject to curtailment if congestion appears.

Firm transactions into or out of the NYCA will be scheduled based on economics and Available Transmission Capacity. A load being supplied by a Firm Import transaction or from an internal generator will have a financial schedule equal to the amount of transmission service scheduled. If the Import is curtailed, or the internal Generator is dispatched below the amount of the transaction, the Load will be supplied with Energy from the LBMP Market. A generator supplying a Firm bilateral transaction, either internally or for export, will have an operational physical schedule based upon its Energy offer. Thus, a load being served by a Firm bilateral transaction will have a financial transaction schedule; but the generator supplying that transaction will have a separate operational physical schedule.

In general, under NYISO/LBMP operation, if a Firm bilateral transaction is physically cut or curtailed, its financial schedule will remain intact. Thus, generation may be dispatched down, and DNI schedules may be reduced (as is currently done to cut transactions), but the financial obligations will remain. Financial schedules that differ in real-time from those scheduled Day-Ahead will balance the differences in the real-time LBMP Market (*i.e.* the balancing market).

If a Non-Firm transaction is physically cut or curtailed, the transaction is eliminated. As a default, except in the case of wheel-throughs, a generator previously supplying a cut Non-Firm transaction will bid into the LBMP Energy Market, and a load previously being supplied by a Non-Firm transaction will be served by the LBMP Energy Market.

Self Cancellation (Withdrawal) of Bilateral Transactions

A supplier and load may agree to reduce or eliminate a bilateral transaction previously scheduled in the Day-Ahead Market. In this case, they must submit a revised schedule through RTC. The full Day-Ahead Transmission Usage Charge (TUC) will still accrue. The change in schedule will be settled with Real-Time LBMP Energy and/or the Real-Time TUC.

The following tables will describe the conditions listed below:

- Table 5.1: Scheduling and Physically Curtailing Firm Bilateral Transactions
- Table 5.2: NYISO Curtailment Steps
- Table 5.3: Re-Instatement of Curtailed Bilateral Transactions
- Table 5.4: Transaction Conversion and Curtailment Notifications Required by NYISO
- Table 5.5: Scheduling and Dispatching LBMP Suppliers and Loads

Table 5.1 Scheduling and Physically Curtailing Firm Bilateral Transactions

Summary Table Scheduling and Physically Curtailing Firm Bilateral Transactions								
	Internal Source				External Source			
	Internal Load		External Load (Export)		Internal Load (Import)		External Load (Wheel-Through)	
	(1) Transmission Service: Financial Transaction Schedule	(2) Transaction Source: Operational Physical Schedule	(3) Transmission Service: Financial Transaction Schedule	(4) Transaction Source: Operational Physical Schedule	(5) Transmission Service: Financial Transaction Schedule	(6) Transaction Source: Operational Physical Schedule	(7) Transmission Service: Financial Transaction Schedule	(8) Transaction Source: Operational Physical Schedule
A. Day-Ahead	Set to full Requested MW Amount submitted in transaction bid	Source Scheduled economically based on submitted energy offer Supplier buys in LBMP market for shortfall	Up to Full Requested Amount Based on Day-Ahead transaction bids Limited to Applicable ATC*. *	Source Scheduled economically based on submitted energy offer Supplier buys in LBMP market for shortfall Total Exports Limited to ATC	Full Requested MW Amount submitted on transaction bid	Up to Day-Ahead Financial Schedule based on the economics of the transaction bid. Total Imports Limited to ATC un-economic Suppliers not scheduled; Transmission Customer buys LBMP	Up to Full Requested MW based upon Source's Day-Ahead Wheel-Through Dec. Bid with Total Imports and Exports Limited to Applicable ATC*.	Same as Financial Transaction Schedule
B. Hour-Ahead	Same as above for comparable Day-Ahead case ***except*** using Hour-Ahead bilateral schedule requests ***and*** no Forward Commitment is issued*.							
C. Day-Ahead or Hour-Ahead Schedule Supplier is Un-economic in Real-Time	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Supplier Dispatched Down in Real-Time. Supplier buys in LBMP market for shortfall	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule is Fixed	Supplier Dispatched Down in Real-Time. No change in DNI takes place. Supplier buys in LBMP market for shortfall	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule is Fixed.	External Suppliers re-evaluated in Real-Time; change in DNI may take place. Real-Timeun-economic Suppliers not scheduled; Transmission Customer buys LBMP	Day-Ahead Schedule and TUC are Fixed; Real-Time Schedule and TUC are also Fixed.	No Re-Dispatch of Supplier and no change in DNI takes place Real-Time, un-economic Suppliers not scheduled; Transmission Customer balances any day-ahead TUC charges at real-time LBMP prices

						market for shortfall		
D. Security Violation Occurs in Real-Time	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed	Supplier Dispatched Down and/or decommitted in Real-Time if Needed. No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed.	Supplier Dispatched Down and/or decommitted in Real-Time if Needed. No Change takes place in Load Schedule and DNI in Real-Time unless Energy Transaction is curtailed under Emergency Procedures	Day-Ahead Schedule and TUC are Fixed; Hour-Ahead Schedule is Fixed.	Supplier Re-Scheduled Down (“Curtailed”) in Real-Time if Needed; DNI also changed. No Change in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures	Day-Ahead TUC balanced at RT TUC prices if curtailed	Supplier Re-Scheduled Down (“Curtailed”) and Energy Transaction is curtailed in Real-Time if Needed; DNI changed to reflect both curtailments.
E. A scheduled Day-Ahead Transaction is Self Canceled (Withdrawn) by Supplier (Source) or LSE (Sink) Prior to HAM evaluation	Day-Ahead Schedule and TUC are Fixed; transaction cannot be withdrawn	Economic bid of source may be modified and the source will be scheduled based on the economics of the revised bid	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set to 0 .	Source and Sink update schedule in RTC. DNI is changed (in Real-Time).	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set = 0.	Source and Sink update schedule in RTC. DNI is changed.	Day-Ahead Schedule and Price are Fixed; Real-Time Schedule is set = 0	Source and Sink update schedule in RTC. DNI is changed. to reflect both curtailments

* Financial Transaction Schedule must result in a physically feasible flow-based solution in SCUC or RTC; determination of Firm transactions that cannot be scheduled will be based on the Sources' Decremental Bids.

ATC = Available Transfer Capability of applicable transmission flow-gate.

In general, Day-Ahead supplier scheduled for less than its scheduled transactions buys replacement energy at its bus at Day-Ahead LBMP (transaction pays Day-Ahead TUC).

Day-Ahead supplier that is off-schedule in supporting a scheduled transaction settles up with Real-Time Energy LBMP.

Day-Ahead Transmission Customer load that is off-schedule in its scheduled transaction settles up with Real-Time TUC.

Both SCUC and RTC perform a screening function by looking ahead and not "scheduling" a Non-Firm Bilateral Transaction if it is anticipated to contribute to positive congestion.

Table 5.2 NYISO Curtailment Steps

Corresponding TLR Level	Minimum NERC Required Action
TLR 1	Notify Reliability Coordinators of potential SOL or IROL Violations
TLR 2	Hold transfers at present level to prevent SOL or IROL Violations
TLR 3a	Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
TLR 3b	Curtail Interchange Transactions using Non-firm Transmission Service Arrangements to mitigate a SOL or IROL Violation
TLR 4	Reconfigure Transmission
TLR 5a	Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
TLR 5b	Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation
TLR 6	Emergency Procedures
TLR 0	TLR concluded

Table 5.3 Re-Instatement of Curtailed Bilateral Transactions

Re-Instatement of Physically Curtailed Transactions	
Type of Curtailment	**Re-Instatement**
Non-Firm transaction previously "scheduled" (on advisory basis) by SCUC or RTC that is curtailed in Real-Time	Must Re-Submit Schedule Request thru RTC (may already be in queue)
Firm Inter-Control Area transaction previously scheduled by ***SCUC*** that is physically curtailed (DNI schedule change) by RTC or in Real-Time to solve a security violation	May Re-Submit Schedule Request thru RTC (may already be in queue)
Firm Inter-Control Area transaction previously scheduled by ***RTC*** that is physically curtailed (DNI schedule change) in Real-Time to solve a security violation	May Re-Submit Schedule Request thru RTC (may already be in queue)
Transaction previously scheduled by SCUC or RTC is ***self canceled*** by Supplier or LSE	May Re-Submit Schedule Request thru RTC (may already be in queue)

Table 5.4 Transaction Conversion Curtailment Notifications Used by NYISO

Transaction Conversion and Curtailment Notifications Used by NYISO	
Action	**Notification**
Conversion of generators and loads associated with Internal, Import and/or Export Non-Firms to LBMP Energy market participants (TLR).	Automatic E-Mail to financially responsible party
Physical curtailment (through DNI schedule change) of Inter-Control Area Non-Firm transactions (TLR 2c)	Automatic E-Mail to financially responsible party; Phone call to the affected Control Areas (which in turn should notify the Source and Sink); Phone call to affected Transmission Provider(s) for exports; otherwise E-Mail to affected Transmission Providers
Physical curtailment (through DNI schedule change) of unscheduled loop-flow Non-Firm transactions (TLR 3)	Phone call to the affected Control Areas (which in turn should notify the Source and Sink)
Physical curtailment (through DNI schedule change) of Firm External Source to Internal Sink Transaction (Import)	Automatic E-Mail to financially responsible party. Phone call to affected Control Area (which in turn should notify the Source), and E-Mail to affected Transmission Provider(s) and the Sink
Physical curtailment (through DNI schedule change) of Firm Internal Source to External Sink Transaction (Export)	Automatic E-Mail to financially responsible party. Phone call to affected Control Area (which in turn should notify the Sink), and phone call to affected Transmission Provider (which in turn should notify the Source)
Physical curtailment (through DNI schedule change) of Firm External Source to External Sink Transaction (Wheel-Through)	Automatic E-Mail to financially responsible party. Phone call to the affected Control Areas (which in turn should notify the Source and Sink), and E-Mail to affected Transmission Provider(s)
Source = Supplier at Point of Injection (POI) Sink = Load at Point of Withdrawal (POW)	

Table 5.5 Scheduling and Dispatching LBMP Suppliers and Loads

Scheduling and Dispatching LBMP Suppliers and Loads								
	Internal Suppliers		Internal Loads		External Suppliers (Import with Marcy as Point-of-Withdrawal – POW)		External Loads (Export with Marcy as Point-of-Injection – POI)	
	(1) Financial Schedule	(2) Operational Schedule	(3) Financial Schedule	(4) Operational Schedule	(5) Financial Schedule	(6) Operational Schedule	(7) Financial Schedule	(8) Operational Schedule
A. Day-Ahead	Based on Day-Ahead Bids	Same as Day-Ahead Financial Schedule	Full Requested Amount for Fixed MW Loads; or Based on Day-Ahead Bids for Price Capped Loads	Same as Day-Ahead Financial Schedule	Based on Day-Ahead Incremental Bid with Total Imports Limited to ATC	Same as Day-Ahead Financial Schedule	Full Requested Amount or Based on Day-Ahead Bids for Price Capped Loads*. Total Exports Limited to ATC.	Same as Day-Ahead Financial Schedule
B. Hour-Ahead	Based on Hour-Ahead Incremental Bids	Dispatched in Real-Time	Not Available		Based on Hour-Ahead Incremental Bids with Total Imports Limited to ATC	Same as Financial Schedule	Full Requested Amount Based on Hour-Ahead Bids for Price Capped Loads* with Total Exports Limited to ATC	Same as Financial Schedule
C. Day-Ahead or Hour-Ahead Supplier is Uneconomic in Real-Time	Day-Ahead Schedule and Price are Fixed; differences settled in real-time	Supplier Dispatched Down in Real-Time; settled in Real-Time	Day-Ahead Schedule and Price are Fixed		Day-Ahead DNI Schedule and Price are Fixed	No Re-Dispatch of Supplier and no change in DNI takes place.	Day-Ahead DNI Schedule and Price are Fixed; Hour-Ahead DNI schedule are Fixed for hourly transactions.	
D. Security Violation Occurs in Real-Time	Day-Ahead Schedule and Price are Fixed	Supplier Dispatched Down and/or de-committed in Real-Time if Needed	Day-Ahead Schedule and Price are Fixed	No Change takes place in Load Schedule in Real-Time unless Load Curtailment is invoked under Emergency Procedures	Day-Ahead Schedule and Price are Fixed; Hour-Ahead and Intra-hour Schedule is Fixed.	Supplier Re-Scheduled Down ("Curtailed") in Real-Time if Needed; Also DNI is changed	Day-Ahead Schedule and Price are Fixed; Hour-Ahead and Intra-hour Schedule is Fixed.	No Change in Load Schedule in Real-Time unless Energy Export is Curtailed under Emergency Procedures; then DNI is also changed

Scheduling and Dispatching LBMP Suppliers and Loads								
	Internal Suppliers		Internal Loads		External Suppliers (Import with Marcy as Point-of-Withdrawal – POW)		External Loads (Export with Marcy as Point-of-Injection – POI)	
	(1) Financial Schedule	(2) Operational Schedule	(3) Financial Schedule	(4) Operational Schedule	(5) Financial Schedule	(6) Operational Schedule	(7) Financial Schedule	(8) Operational Schedule
E. Day-Ahead or Hour-Ahead Schedule is Self Canceled by Supplier or LSE	Day-Ahead Schedule and Price are Fixed	Supplier updates schedule in RTC; NYISO updates RTD or Outage Scheduler	Day-Ahead Schedule and Price are Fixed		Day-Ahead Schedule and Price are Fixed	Supplier updates schedule in RTC; NYISO updates DNI and RTD or Outage Scheduler	Day-Ahead Schedule and Price are Fixed	LSE updates schedule in RTC; NYISO updates DNI

* Financial Schedule must result in a physically feasible flow-based solution in SCUC or RTC.
ATC = Available Transfer Capability of applicable transmission flow-gate.
Internal Suppliers are dispatchable in Real-Time.
External Suppliers are pre-schedulable Day-Ahead or Hour-Ahead, but not dispatchable in Real-Time.
Marcy is used as a reference bus where noted.

5.2.4 Dispatch Day Scheduling Priority for Day-Ahead External Transactions

For Real-Time Import and Wheel-Through transactions, not using a CTS Interface Bid, a "Decremental Bid" (Dec Bid) amount is used in the RTC. The highest economic scheduling priority that can be supplied by Market Participants is -$1000.00 for RT Dec Bids. A Dec Bid reflects the minimum the MP is willing to accept to import energy into the NYCA.

For Real-Time Export transactions, not using a CTS Interface Bid, Market Participants supply a "Sink Price Cap" amount up to $1000.00. A Sink Price Cap Bid reflects the maximum the MP is willing to pay to get its energy export scheduled.

For Import or Export transactions using a CTS Interface Bid, Market Participants supply a Bid Price which indicates the bidder's willingness to be scheduled so long as the forecasted CTS Sink Price minus the forecasted CTS Source Price is greater than or equal to the dollar value specified in the Bid. The highest economic scheduling priority than can be supplied by Market Participant using a CTS Interface Bid is -$1000.00.

Decremental Bids (Imports)

An accepted, Day-Ahead Import that is not designated as a CTS Interface Bid for the Real-Time Market will be converted to a Real-Time Market bid using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of - $0.01 will be used when the DAM bid is converted to a bid for the Real-Time Market.

Decremental Bids (Wheels)

A Wheel-Through that is accepted in the DAM will be converted to a bid for the Real-Time Market using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of - $1000.00 will be used when the DAM bid is converted to a bid for the Real-Time Market.

Sink Price Cap Bids (Exports)

An accepted, Day-Ahead Export that is not designated as a CTS Interface Bid for the Real-Time Market will be converted to a Real-Time Market bid using the "RTM Bid Price" provided in the Market Participant's DAM bid. If the Market Participant does not provide a "RTM Bid Price" when submitting its DAM bid, a default economic scheduling priority of + $1000.00 will be used when the DAM bid is converted to a bid for the Real-Time Market.

CTS Interface Bids (Imports and Exports)

An accepted, Day-Ahead Import or Export that is designated as a CTS Interface Bid for the Real-Time Market will be converted to a bid for the Real-Time Market using the "RTM Bid Price" provided in the Market Participant's DAM bid. Market Participants must specify a "RTM Bid Price" when submitting an Import or Export designated as a CTS Interface Bid for the Real-Time Market, whereas this field is optional for Decremental bids and Sink Price Cap Bids.

A Market Participant also has the option of modifying its Real-Time Market Bid, regardless of whether the Bid has an MP-specified "RTM Bid Price," or the Bid was adjusted by the MIS to the applicable default economic scheduling priority, as outlined above. After the Day-Ahead checkout process with neighboring Control Areas, the Real-Time Market Bid can be adjusted for megawatts and/or price by the MP before the close of each hourly RT Market. In this instance the entire megawatt amount of the transaction will be evaluated by the RTC with this new price.

5.3 Capacity Limited and Energy Limited Resources

Many generating units have limitations on their ability to operate for a period of time over all, or a portion, of their operating range. Classification as a Capacity Limited Resource (CLR) or the sub-classification of Energy Limited Resource (ELR) may qualify such generating units for special balancing energy and Installed Capacity (ICAP) consideration while making energy and/or capacity limited MWs available to the Day-Ahead, In-Day, and Real-Time Markets. Additional information on CLR and ELR usage can be found in Attachment M of the *NYISO Installed Capacity Manual (*available from the NYISO Web site at the following URL:
http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp)

5.4 Normal and Emergency Upper Operating Limits (UOLN and UOLE)

All energy Suppliers are required to specify both a Normal Upper Operating Limit (UOL_N) and an Emergency Upper Operating Limit (UOL_E) in their Day-Ahead ("DA") and Real-Time ("RT") offers. The UOL_N defines the unit's operating limit under normal system conditions; the UOL_E defines the unit's operating limit achievable at the request of the NYISO during extraordinary conditions. Both limits should reflect the unit's achievable capacity. The specified value of UOL_E in the DA and RT offers must be greater than or equal to value specified for UOL_N. Additional information on Upper Operating Limits for CLR and ELR resources can be found in Attachment M of the *NYISO Installed Capacity Manual* (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

5.5 Inter-Control Area ICAP Energy

With few exceptions, all NYISO ICAP providers have an obligation to submit bids into the NYISO Day-Ahead Market on a daily basis. This obligation applies to ICAP providers located both within and external to the NYCA. Rules governing the obligations associated with NYISO ICAP contracts are defined in the *NYISO Installed Capacity Manual (*available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

PJM, ISO-NE, and the NYISO have agreed to a number of "General Principles" to facilitate access to the energy associated with ICAP contracts with suppliers located in external control areas in the event of a capacity shortage within a control area.

NYISO ICAP Suppliers Located in PJM or New England

In the event that energy from a NYISO ICAP resource located in PJM or New England is required to resolve a capacity deficiency in the NYCA, the NYISO dispatcher will contact the ICAP resource's designated contact. The NYISO dispatcher will instruct the designated contact to ensure that all necessary measures are taken to facilitate delivery of the ICAP backed energy to the NYCA in response to a Supplemental Resource Evaluation (SRE) request, or through the next Real-Time Commitment (RTC).

Resources from Quebec

In the event that NYISO ICAP backed energy is required from Quebec, the NYISO Dispatcher will contact the designated resource contact and instruct the contact to take the actions necessary to facilitate the delivery of the ICAP backed energy in response to an SRE request, or through the next RTC.

Resources from NYISO

The NYISO is committed to a high level of deliverability for energy from the NYCA that supports an ICAP contract in an external control area. In the event that a neighboring control area has an in-day forecasted or actual reserve shortage (e.g. a PJM Maximum Generation Emergency), the affected control area dispatcher will contact their ICAP

resource(s) located within the NYCA to request their ICAP contract energy. They will also notify the NYISO dispatcher of the situation. The ICAP resource is expected to follow the NYISO bidding rules required to get the ICAP backed energy scheduled for export. In the event that the export transaction(s) is not accepted by RTC due to a NYISO reserve shortage, the NYISO dispatcher will input the transaction using IS+.

Interface Limit Reductions

System transmission conditions at times may require a reduction in the external interface limits for a specific control area. In the event that the ICAP entitlement associated with a specific external control area is less than or equal to the reduced interface limit, then the external control area will be entitled to the contracted ICAP amount. In the event that the ICAP entitlement for an external control area is greater than the reduced interface limit, then the NYISO will schedule the deliverable quantity based on the RTC where time permits. In real time, the external control area dispatcher may contact the NYISO dispatcher and identify the specific external ICAP transactions that they wish to curtail. If the external control area dispatcher does not specify the ICAP transactions to be curtailed, then the NYISO dispatcher will perform curtailments based upon existing operational procedures for locational curtailment. In either event, the export transactions will be scheduled or curtailed to a level consistent with the reduced interface limits.

5.6 Emergency Demand Response Program and Special Case Resources

The Emergency Demand Response Program (EDRP) provides a mechanism for load reduction during emergency conditions, thereby facilitating the reliability of the New York State bulk power system. Forecast reserve shortages may be shortages for the NYCA statewide region, locational shortages within the NYCA region due to transmission constraints, or inter-regional locational shortages between NYCA and neighboring Control Areas due to transmission constraints. A complete description can be found in the *NYISO Emergency Demand Response Manual* (available from the NYISO Web site at the following URL:
http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp) .

Retail end users who agree to participate in the EDRP can be accommodated through one of four types of Curtailment Service Providers (CSPs):

1. Load Serving Entities (LSEs), either that currently serving the load or another LSE
2. Through NYISO-approved Curtailment Customer Aggregators
3. As a Direct Customer of the NYISO
4. As a NYISO-approved Curtailment Program End Use Customer.
5. Curtailment Customer Aggregators and Curtailment Program End Use Customers must register with the NYISO as Limited Customers.

Voluntary Participation

Participation in the EDRP is voluntary and no penalties are applied if a CSP fails to respond to a NYISO notice to reduce load.

Retail end users participating in the EDRP cannot participate in the NYISO's Special Case Resources (SCR) Program. SCRs that have registered with the NYISO but not sold their capacity will be added to the list of EDRP participants for that period of time when their capacity is unsold, and will be called with EDRP participants if an EDRP event is activated.

The NYISO will allow participation by aggregations of smaller customers, the curtailed usage of which will be determined by using an alternative to the basic provisions regarding the metering and measurement of performance. Distributed Generation (DG) and self-generation resources are not eligible. Direct serve customers are also prohibited from operating under alternative performance measures.

NYISO Notification

It is the NYISO's intention to provide CSPs notice no less than two hours in advance of the time specified to reduce load, pursuant to NYISO emergency operations procedures. However, instructions may be issued requesting an immediate start.

Special Case Resources

Special Case Resources are Loads capable of being interrupted upon demand, and distributed generators that are not visible to the NYISO's Market Information System. The Unforced Capacity of a Special Case Resource corresponds to its pledged amount of Load reduction as adjusted by historical performance factors and as increased by the Transmission District loss factor. For details, refer to the *NYISO Installed Capacity Manual*, available from the NYISO Web site at the following URL:

http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp

5.7 Scheduling Operations Procedures

The following procedures are intended for the scheduling operations that occur during the Dispatch Day, but prior to operations, which occur during the Dispatch Hour:

- Interaction with Real-Time Commitment
- Interaction with Real-Time Automated Mitigation Process
- Interaction with Fast Start Management
- Anticipated Operating Reserve Shortages
- Out-of-Merit Generation
- Supplemental Commitment Process

5.7.1 Interaction with Real-Time Commitment

Hour-ahead scheduling is performed on a periodic basis and is completed at least 45 minutes prior to the beginning of the dispatch hour.

NYISO Actions

The NYISO performs the following:

1. Updates the power system grid model based on the latest transmission outage schedules, including forced outages.
2. Updates the load forecast based on the latest load information.
3. Accepts any updated reserve requirements.
4. Accepts the day-ahead schedules and firm transaction schedules.
5. Accepts the hour-ahead generation bids and firm transaction bids.
6. Accepts the telemetered phase shifter and tap settings from SCADA with adjustments made for known schedule changes.
7. Executes the Real-Time Commitment (RTC) using SCUC with a 2½ hour horizon.

Posts the following results:

1. Revised generator schedules for the next hour.
2. Revised firm transaction schedules for the next hour.
3. Market Participant Actions.
4. Market Participants shall request the NYISO for any changes in generation, load, and transactions schedules.

5.7.2 Interaction with Fast Start Management

The fast start management (FSM) function allows NYISO operations staff to start or stop, or delay the turning on or turning off of specified "fast start" generators (typically, gas turbines). The FSM function will normally operate in a mode where all first time fast start unit basepoints are held back until the system operators give an explicit approval for the basepoints to be sent to the unit.

Additionally, all fast start units' startups and shutdowns must be first approved by system operators. There will be messages to the operators indicating when a fast start unit has met its minimum run time and is not economic to run.

In the Reserve Pickup and Maximum Generation Pickup (RTD-CAM) modes, the default will be for fast start units' schedules to be sent out without system operator approval.

Table 5.6 summarizes the startup characteristics for real-time commitment.

Table 5.6 Unit Startup Characteristics

Unit Classification	Startup Characteristics
Fast Start Units*	10-15 minute startup notice starts by RTC on the quarter hour On-Demand starts by RTD-CAM
Slow Start Units	30-minute startup notice starts by RTC on the quarter hour
* Also known as Quick Start Units	

5.7.3 Anticipated Operating Reserve Shortages

The NYISO prepares the NYISO daily status report twice daily, in anticipation of the morning peak and the evening peak. Forecasted loads and operating capacity, including maximum generation capability and all firm transactions for the hours of the expected peak are provided by the Eligible Customers of the NYISO. The NYISO also provides a forecasted peak load based on NYISO data for comparison to that supplied by the TOs.

Resource Categories

There are ten Resource Categories as shown by

Table 5.7

Table 5.7 Resource Categories

Resource Categories									
(R1) Energy	(R2) AGC Regulation Reserve	(R3) 10 Min Spin Reserve	(R4) 10 Min Non-Synch Reserve	(R5) 30 Min Reserve (Internal or External Reserve Activation)	(R6) FRED*	(R7) Simultaneous Active of Reserves and/or External Emergency Purchases	(R8) Unexpired Un-accepted Day-Ahead Bids	(R9) Unexpired Un-accepted Hour-Ahead Bids	(R10) Involuntary Load Curtailment
Regulating resources or Dispatchable or Non-Dispatchable	Regulating resources	Dispatchable or Non-Dispatchable	Dispatchable or Non-Dispatchable and Off-Line but Available	Dispatchable or Non-Dispatchable and Off-Line but Available	Dispatchable or Non-Dispatchable and Off-Line but Available	Invoked Manually	Non-Dispatchable or Off-Line but Available	Non-Dispatchable or Off-Line but Available	Invoked Manually
FRED = **F**orecast **R**equired **E**nergy for **D**ispatch; the capacity to supply energy to meet NYISO forecasted load that is in excess of the sum total of Day-Ahead load bids.									

Existing Real-Time Non-SRE Resource Adjustments are listed as follows:

1. AGC moves regulating resources from (R2) to (R1) and from (R1) to (R2) to maintain regulation.
2. RTD moves "Dispatchable" (On-Line or Off-Line) resources between (R1), (R2), (R3), (R4), (R5) and (R6) to balance load with generation and maintain reserves.
3. If RTD can't solve rapidly enough for an energy deficiency, Reserve Pickup is invoked to move some "Dispatchable" and "Non-Dispatchable" resources from (R2), (R3), and (R4) at emergency response rates (and from Internal (R5) and (R6) at normal response rates or faster) into (R1) to rapidly eliminate the deficiency.

> ***Note:*** LESRs will not respond to reserve pickups except to either maintain any injection or terminate any consumption of energy.

4. During a Reserve Pickup – RTD-CAM is used to convert 10-Minute Operating Reserve to energy using emergency response rates for some or all suppliers

providing operating reserve and normal response rates for some or all other suppliers if needed. Reserve Pickup, which only dispatches suppliers upwards, looks at control error and load trending approximately 10 minutes ahead, and allows approximately 10 minutes for the reserve pickup to occur.

Reserve pickup may occur if energy becomes deficient due to the loss of a large generator; to return schedules if the ACE exceeds 100 MWs; or if a faster ramp rate is required to solve a transmission security violation.

During Reserve Pickup, no regulation penalty is invoked for generators that exceed their RTD basepoint (i.e., over-generation is encouraged and rewarded). Reserve Pickup will be terminated by the Operator when a sufficient level of energy has been replaced. Upon this termination, generator basepoints will be initialized at their ending actual levels.

Locational Reserve Pickup may be invoked to solve a specific locational energy deficiency or transmission violation.

5. For losses of large generators, Simultaneous Activation of Reserves may be invoked to move resources from (R7) into (R1) to rapidly eliminate the energy deficiency.

Simultaneous Activation of Reserves is utilized for a condition in which a number of neighboring control areas performs a Reserve Pickup to replace energy on a regional basis. The control area that required the replacement of energy will ultimately pay back the energy to neighboring control areas as an inadvertent energy payback.

6. If steps 2, 3, and/or 4 are insufficient, External Reserve Activation may be invoked to move resources from External (R5) and (R6) into (R1) to rapidly eliminate the energy deficiency.

Upon an External Reserve Activation, Interchange Scheduler Plus (IS+) is used to perform an evaluation to change DNIs with neighboring control areas to allow interruptible exports to be cut, and to allow externally procured operating reserves to be converted to energy and imported.

7. If Reserve Pickup is (or is expected to be) insufficient, Max Gen Pickup may be invoked manually through phone notifications to TOs to move "Dispatchable" and "Non-Dispatchable" resources (R2), (R3), and (R4) at emergency response rates (and Internal (R5) and (R6) at normal response rates or faster) into (R1) to rapidly eliminate the energy deficiency.

> ***Note:*** LESRs will not respond to reserve pickups except to either maintain any injection or terminate any consumption of energy.

A Maximum Generation Pickup is an emergency energy pickup as directed by the NYISO outside a normal RTD run. At the NYISO's judgment, generators will be instructed via voice communication to increase output to their upper operating limits as soon as possible until directed otherwise. This is typically invoked to relieve a transmission violation rapidly.

8. If a reliability violation continues to occur, prescribed corrective actions should be taken which may include postponement or cancellation of scheduled transmission outages according to procedures defined in the *NYISO Outage*

Scheduling Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp). This may also include curtailment of external transactions.

9. If a reliability violation continues, External Emergency Purchases may be invoked to move resources from (R7) to (R1).
10. If other steps are insufficient in quantity and/or speed, Involuntary Load Curtailment (including possibly Load Shedding) may be invoked according to prescribed procedures to move (R10) into (R1) to rapidly eliminate the energy deficiency.
11. As a follow-up to the above steps, subsequent RTD runs will move Internal "Dispatchable" resources (R5) and (R6) into (R1) to replenish diminished regulation and 10 minute reserves.

If the data indicates that the NYCA will be short of Operating Reserve, the NYISO shall perform the actions described for supplemental commitment and scheduling.

5.7.4 Out-of-Merit Generation

From time to time, generators must be operated out of economic order or at levels that are inconsistent with the calculated schedules. Any NYISO-authorized deviation from the schedule is considered Out-of-Merit (OOM) Generation and is not subject to regulation penalties. A unit that is out-of-merit is balanced at actual output and may be eligible for a supplemental payment if its bid production cost is not met.

NYISO Requests for Out-of-Merit Generation

Out-of-Merit Generation, either up or down, can be requested by the NYISO for security of the bulk power system, during communication failures, or because the Real-Time Commitment does not successfully run. The energy provided during the out-of-merit condition will be paid at the Real-Time Market Locational Based Marginal Pricing (LBMP) rates, but out-of-merit units may not set LBMP rates. The unit will be provided a supplemental payment, if required to recover its bid cost, consistent with the rules for bid production cost guarantees.

Any supplemental payments will be charged to all NYISO Loads through the Schedule 1 Ancillary Service. The generator will be put back in merit by the NYISO when conditions warrant.

Transmission Owner Requests for Out-of-Merit Generation

Transmission Owners in the NYISO system can request that a generator be run out-of-merit, either up or down, for local reliability. The specific generator and reason for the request must be identified by the TO at the time of the request. The energy provided by the generator will be paid at the Real-Time Market LBMP rates, but OOM units may not set LBMP rates. The unit will be provided a supplemental payment, if required to recover its bid cost, consistent with the rules for bid production cost guarantees. Any supplemental payments will be charged to the Loads within the TO's area. The generator will remain out-of-merit until the TO requests that the NYISO put it back in merit.

Generator Operator Requests for Out-of-Merit Generation

Generator operator requests for OOM Generation must be made through the TO. The specific reason for the request is required at the time the request is relayed by the TO to the NYISO. The generator will remain out-of-merit until the generator operator requests, via the TO, that the NYISO put it back in merit.

A generator operator may request out-of-merit operation to perform a Dependable Maximum Net Capability (DMNC) test. The process for this test is described in Section 5.7.5. During a DMNC test, energy that is scheduled in the Day-Ahead Market (DAM) is covered by a bid production cost guarantee. Energy that is not scheduled in the DAM will be paid for at the Real-Time Market LBMP rate, and it will not receive an in-day bid production cost guarantee. Out-of-Merit Generation will not set LBMP rates.

Derated generation can also be requested by a generator operator for extenuating circumstances that require reduced operation or shutdown. This includes equipment failure or pollution episodes. The generator remains responsible for balancing energy.

5.7.5 Generator DMNC Test Scheduling Requirements

Test Scheduling Notification Rules

For Generators 100 MW and greater; the Generator notifies the NYISO Scheduling Department (see immediately above) and the Transmission Owner (TO) at least five (5) business days in advance of the proposed test date that the Generator is requesting a DMNC test.

For Generators 25 to 99 MW, (including multiple units under a single owner totaling more than 25 MW), the Generator notifies the NYISO Scheduling Department and the TO at least two (2) business days in advance of the proposed test date that the Generator is requesting a DMNC test. Generators under 25 MW testing separately have no notification requirements.

The NYISO will conduct a system reliability review and notify the Generator through the TO if, and only if, the request is denied.

Day-Ahead Bidding

Generators 100 MW and greater must bid into the Day-Ahead energy market such that the Generator is scheduled for the hours requested for the DMNC test. If the Generator is not scheduled, the DMNC test is cancelled and notification must be made to NYISO Scheduling (at the number/email address above in red) and the TO by hour 1400 of the business day prior to when the DMNC test is scheduled.

For Generators 25 to 99 MW, a Day-Ahead bid is not required if the Generator is a unit that can be committed through Real-Time Commitment (RTC). In the event of a test cancellation the Generator must notify NYISO Scheduling and the TO by hour 1400 of the business day prior to when it is requesting a DMNC test.

Test Day Procedures

On the day of the scheduled DMNC test, at least three (3) hours prior to the scheduled test, the Generator, through the Transmission Owner, must request permission from the NYISO to perform the test. Also, the Generator, regardless of size, (i.e., with or without a DAM schedule), must ensure that in the Real-Time Market the unit is scheduled for the hours requested for the DMNC test, including ramping up to the test level. The NYISO will approve or deny the request at least two (2) hours prior to the scheduled test, notifying the Generator through the Transmission Owner, allowing time for Real-Time Market energy market bid adjustments.

On the day of the test, the Generator is required to adjust its (price-taking) Real-Time Market bid to allow Real-Time Dispatch (RTD) to schedule the Generator up to its current DMNC rating.

The Generator must notify the NYISO through the Transmission Owner that the DMNC test has started.

The NYISO will log that the Generator is performing a DMNC test and that the Generator is dispatched out-of-merit.

The Generator must notify the NYISO through the Transmission Owner that the test is complete. The NYISO will log the completion time and the Generator will resume following normal base points.

Accounting for and Submitting DMNC Test Results

During the Generator's DMNC test period, the Generator will not set the LBMP.

For the energy that is not subject to Day Ahead LBMP, the NYISO will pay the Generator the LBMP in the Real-Time Market at its location for the energy it produced during the Generator's DMNC test.

The NYISO will not charge the Generator for any performance and regulation penalties that may apply during the Generator's DMNC test period.

The Generator must submit DMNC test results data online, (including weather-adjusted data), as defined in the ICAP Automated Market User's Guide, Section 11, and section 4.2 of the NYISO Installed Capacity Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

5.7.6 Supplemental Commitment Process

The NYISO may use the SRE process to commit additional resources outside of the SCUC and RTC processes to meet NYISO reliability or local reliability requirements. Transmission Owners (TOs) may request the commitment of additional generators to ensure local reliability in accordance with the local reliability rules. The NYISO will use SREs to fill these requests by TOs. In addition, Generator Owners may request the operation of a specific steam unit if certain combustion turbines have an energy or a non-synchronous reserve schedule that necessitates operation of the steam unit due to 24-hour NO_X Averaging Period requirements.

When the NYISO requests that generators submit bids in response to an SRE, ICAP suppliers must offer their available capacity unless an offer is pending in the Real Time market when the SRE request is made or the unit is unable to run due to an outage, operational issues or temperature derates. Special Case Resources are not required to respond to SRE requests by section 5.12.1 of the Market Services Tariff. However, the NYISO may request SCR and EDRP resources to respond to SRE requests on a voluntary basis.

Since SREs are only performed to address reliability concerns, it is intended that units committed by the SRE process fulfill their obligation by physically operating.

NYISO Requests for SREs

The NYISO may perform SREs in response to the following three conditions:

1. When Day-Ahead reliability criteria violations are forecast after SCUC has begun or completed its Day-Ahead evaluation (i.e.: too late for additional day-ahead commitments).
2. When In-Day reliability criteria violations are anticipated more than 75 minutes ahead (i.e.: too early for RTC commit additional resources)..

Transmission Owner Requests for SREs

TOs may request the NYISO to issue an SRE to commit additional resources for reliability purposes in a local area. TO requests for SREs are subject to the same conditions and the same time frame as the NYISO's use of the SRE process – after SCUC has run. Any requests by TOs to commit generators not otherwise committed by the NYISO in the Day-Ahead Market will be posted to the OASIS.

When requesting an SRE, TOs must give the NYISO the reliability reason for the request, the expected duration of the SRE, and the specific facility or constraint affected. NYISO dispatchers will log all such TO requests for SREs. Within 5 business days the TO requesting the SRE commitment shall provide detailed written justification for the SRE to SREinfo@nyiso.com. The NYISO will review all SRE requests to ensure that practices being followed are consistent with NYISO tariffs and NYS Reliability Rules.

The TOs written justification must detail the system conditions that resulted in the need for the SRE commitment such that the NYISO can independently verify the request. The following system conditions should be identified when applicable: TO local area or regional load levels; identification of thermal transmission facility or substation voltage constraint, identification of whether the constraint represents a predicted actual or post-contingency violation; identification of significant transmission or generating unit outages affecting such constraint; and identification of special local reliability criteria. Other local area system conditions that resulted in the need for the SRE commitment should also be identified.

Generator Owner Requests for SREs

If certain combustion turbines have an energy or a non-synchronous reserve schedule that necessitates the operation of a specific steam unit operated by the turbine owner due to 24-hour NO_X Averaging Period requirements, the NYISO may commit the steam unit if the generator owner takes the the following actions:

- The generator owner shall notify the NYISO and the TO of this operational requirement. The generator owner must notify the NYISO via the TO after the DAM posts, but no later than Hour Beginning (HB) 14 of the day prior to the operating day. In addition, throughout the operating day, the generator owner must communicate to the NYISO via the TO any changes in run-time limitations that may result from the combustion turbine's actual energy schedule or availability.
- The generator owner may request of the NYISO and inform the TO that a specific steam unit be operated, as required, to satisfy the NOx averaging requirements for the selected combustion turbine's energy or non-synchronous reserve DAM schedule given the 24-hour NO_X Averaging Period requirements for the operating day. The generator owner request should identify the steam unit, the required additional hours of operation, and the specific generation levels necessary to meet the 24-hour NOx Averaging Period requirement.

If the combustion turbines are not required for either NYISO or local TO reliability, and the associated steam units are not committed in the DAM, then the NYISO will mark the combustion turbines as unavailable in the generation outage scheduler, such that they are not committed in real-time operation. The combustion turbines will be identified as Energy Limited Resources (ELR), since the generator owner will be unable to fulfill the DAM energy or non-synchronous reserve schedule as determined by the NYISO. Combustion turbines subject to the 24-hour NOx Averaging Period requirement must be registered as Energy Limited Resources.

5.7.7 Supplemental Resource Evaluation Procedures

SRE commitment refers to the NYISO scheduling a generator to start-up to run at, or above, its minimum generation level. SCUC commits resources for the next day, and RTC can commit resources in the Dispatch Day. RTC begins with SCUC Day-Ahead generator and load schedules, non-expired/non-accepted/non-updated (but not SCUC) bids, updated or new bids, updated transaction requests, updated load forecasts, updated outage schedules, and updated status changes. It then evaluates conditions for the next 2 ½ hours, performs a supplemental commitment (if needed) optimized for the next dispatch hour, and schedules newly requested transactions for the next dispatch hour.

The objective function of SCUC is not intended to evaluate energy costs and/or start-up/min gen costs for Day-Ahead capacity forward commitments for non-synchronized reserves. However, RTC will consider start-up costs. A generator started by RTC will be assumed to run at least one hour, so that its start-up bid price will be spread over one hour and added it to its bid energy price in RTC. For the purposes of setting LBMP, only the generator's energy price bid will be used. As with other start-ups, these generators will be eligible for supplemental payments to insure their start-up and minimum generation (for the remainder of the dispatch day) price bids are recovered.

Resource Monitoring Procedures

1. ***Monitor Regulation/Reserve Levels*** – The NYISO shall monitor the level of regulation and reserve resources available to meet anticipated NYCA requirements.

2. ***Monitor Adequacy of Bids*** – The NYISO shall also track the level of unexpired/unaccepted resource bids (R8 and R9) by location as potential replacements for Resources (R1), (R2), (R3), (R4), (R5), and (R6). If certain bid categories are deemed insufficient, the NYISO shall post an announcement to market participants to solicit additional bids.

5.7.8 General SRE Commitment

SRE shall only be used to address resource deficiencies; it shall not be used to reduce costs. The general SRE commitment procedure is as follows:

1. ***Initiate SRE*** – The NYISO shall proceed with an SRE:
   - ✧ If a resource deficiency occurs (or is anticipated to occur), and
   - ✧ If the Existing Real-Time Non-SRE Resource Adjustments steps 1 through 7 are (or are anticipated to be) inadequate, and
   - ✧ If the problem is outside the windows of evaluation for both SCUC and RTC.
2. ***Resource Deficiency*** – The resource deficiency may be a result of:
   - ✧ The subsequent loss of an energy, regulation, or reserve resource;
   - ✧ The loss of a transmission facility;
   - ✧ A load forecasting anomaly; and/or
   - ✧ A resource deficiency forecast but not evaluated by RTC.

More detailed steps are subsequently listed below to specifically describe Day-Ahead and Dispatch Day SRE procedures.

3. ***Define Replacement Required*** – Based on the deficiency, the NYISO will determine:
   - ✧ Type of replacement required (i.e., regulation capability, operating reserve capability, or energy resource). In general, as shown in Table 5.8, the replacement to be selected should match the resource lost.
   - ✧ Location that the replacement is needed
   - ✧ How soon the replacement is required
   - ✧ Amount in MW needed by hour
   - ✧ How long the replacement will be required.

Table 5.8 SRE Replacement Decision

SRE Replacement Decision	
Type of Resource Deficiency	**Type of Replacement Required (To be Selected from Resources R8 or R9)**
(R1) Energy Resource Deficiency	(R1) Energy in Acceptable Location
(R2) Regulation Resource Deficiency	(R2) Regulation in Acceptable Location
(R3)/(R4)/(R5) Operating Reserve Deficiency	(R3)/(R4)/(R5) Same Kind Replacement of Operating Reserves in Acceptable Location
(R6) FRED Deficiency	(R6) FRED – Acceptable Location

4. ***Select Replacement Resources*** – Based on the requirements determined above, the NYISO will select replacement resources from the pre-calculated SRE charts for available unexpired/unaccepted resources (see example chart further below).

Note Exceptions **–** If the NYISO's selection for supplemental resources diverges from the merit order indicated on the applicable chart, the NYISO will need to formally justify and log the exception.

5. ***Solve Dispatch Day (First) and Day-Ahead Deficiencies (Second)*** – In the case in which SCUC has begun or already completed its execution, and a combination of Dispatch Day and/or Day-Ahead resource deficiencies are subsequently anticipated, SRE shall be used to solve any Dispatch Day problems independently first. This shall be followed, if necessary, by another re-evaluation and a second SRE to solve any remaining Day-Ahead problems.
6. ***Allow, but Do not Guarantee "Self"-Replacement by Resource Suppliers*** – A resource that is financially obligated to serve a bilateral transaction or the LBMP spot market may wish to procure its own replacement if possible. In this case, it would need to arrange a Contract-For-Differences (CFD) contract with another resource that would agree to bid into the LBMP market. If that replacement resource were selected through SRE, the original resource would reach a side settlement with it. While the NYISO will not interfere with this type of arrangement, it will also be under no obligation to help facilitate this arrangement by delaying the implementation of an SRE. Alternately, the SRE may select another source for the replacement, presumably, because it is a more economical and/or more effective replacement choice.

5.7.9 Two- to Seven-Day Ahead SRE

A two- to seven-day ahead SRE shall be performed if operating capacity deficiencies are anticipated two to seven days ahead which will require long lead time generators to start-up in advance, i.e., too early for SCUC.

1. ***Post Announcement*** – If a Pre-SCUC SRE is anticipated, and if time permits, the NYISO shall post an announcement to market participants that a Supplemental Resource Evaluation is planned, and that additional resource bids are being solicited.
2. ***Two to Seven Day-Ahead Operating Capacity*** – If any deficiencies in Operating Capacity Resources are expected to exist that require long lead-time start-ups (longer than Day-Ahead):
   - ✧ Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   - ✧ Determine how soon the Supplemental Resource will be needed.
   - ✧ Determine how long, i.e., the Supplemental Commitment Period (SCP) in hours up to the end of the Dispatch Day the Supplemental Resource is likely to be needed.

   Select and schedule the move of Supplemental Resources from available Resource Category (R8) to Category (R6) on a least cost basis where least cost

equals lowest composite start-up and minimum generation costs (if start-up will be required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie-breaker.

5.7.10 Post-SCUC Day-Ahead SRE

A SRE to address a Day-Ahead deficiency would be performed after SCUC has begun its Day-Ahead evaluation.

1. ***Post Announcement*** – If a SRE to address a Day-Ahead deficiency is anticipated, and if time permits, the NYISO shall post an announcement to market participants that a Supplemental Resource Evaluation is planned, and that additional resource bids are being solicited.
2. ***Day-Ahead Regulation or Reserve Deficiency*** – If any deficiencies in Resources (R2), (R3), (R4), (R5), and/or (R6) are expected to exist Day-Ahead after SCUC execution begins and after allowing for Regular Real-Time Non-SRE Resource Adjustment steps 2 through 7:
   - ✧ Determine the amount, location and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.
   - ✧ Determine how soon the Supplemental Resource will be needed.
   - ✧ Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource is likely to be needed.

   Select and schedule the move of Supplemental Resources from Resource Category (R8) to Categories (R2), (R3), (R4), (R5) and/or (R6) on a least cost basis where least cost equals lowest composite availability, and start-up costs and minimum generation costs (if start-up will be required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie breaker.
3. ***Day-Ahead Energy Deficiency –*** If an energy deficiency (R1) is expected to exist Day-Ahead (after SCUC executes) which would result in a reserve deficiency after allowing for Existing Real-Time Non-SRE Resource Adjustments:
   - ✧ Determine the amount and location of Supplemental Resource(s) required to eliminate the energy deficiency.
   - ✧ Determine how soon the Supplemental Resource(s) will be needed.
   - ✧ Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource(s) are likely to be needed.

   Select and schedule the move of Supplemental Resource(s) from Resource Category (R8) to (R1) on a least cost basis where least cost equals lowest composite energy and start-up costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need.
4. ***RTC Re-Adjustment*** – Following steps 2 and/or 3 above, subsequent RTC runs may re-adjust resources.

5.7.11 Dispatch Day SRE

A Dispatch Day SRE would be performed as follows:

1. ***Post Announcement*** – If a Dispatch Day SRE is anticipated, and if time permits, the NYISO shall post an announcement to market participants that a SRE is planned, and that additional resource bids are being solicited.
2. ***Dispatch-Day Regulation or Reserve Deficiency*** – If any deficiencies in Resources (R2), (R3), (R4), (R5), and/or (R6) are expected to exist in the Dispatch Day after allowing for Regular Real-Time Non-SRE Resource Adjustments:

Determine the amount, location and type of Supplemental Resource(s) required. Type should be the same kind of resource that is deficient.

Determine how soon the Supplemental Resource(s) will be needed.

Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day, the Supplemental Resource(s) are likely to be needed.

Select and schedule the move of Supplemental Resources from Resource Category (R8) to Categories (R2), (R3), (R4), (R5) and/or (R6) on a least cost basis where least cost equals lowest composite availability, and start-up costs and minimum generation costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need. In cases in which all other factors are equal, the bid energy price will be used as a tie-breaker.

3. ***Dispatch Day Energy Deficiency*** – If an energy deficiency (R1) is expected to exist in the Dispatch Day, which would result in a reserve deficiency after allowing for Regular Real-Time Resource Adjustments:
   - ✧ Determine the amount and location of Supplemental Resource(s) required to eliminate the energy deficiency.
   - ✧ Determine how soon the Supplemental Resource(s) will be needed.
   - ✧ Determine how long, i.e., the SCP in hours up to the end of the Dispatch Day the Supplemental Resource(s) are likely to be needed.

   Select and schedule the move of Supplemental Resource(s) from Resource Category (R8) to (R1) on a least cost basis where least cost equals lowest composite energy and start-up costs (if start-up is required) spread over the SCP for resources that will be available soon enough to meet the need.
4. ***RTC Re-Adjustment*** – Following steps 2 and/or 3 above, subsequent RTC runs may re-adjust resources.

5.7.12 Real-Time SRE

A Real-Time SRE would be performed as follows:

1. ***Post Announcement*** – If a Real-Time SRE is needed, and time permits, the NYISO shall post, an announcement to market participants that a SRE is being invoked.

2. ***Real-Time Regulation or Reserve Deficiency*** – If any deficiencies in Resources (R2), (R3), (R4), and/or (R6) are expected to exist in Real-Time after Non-SRE Resource adjustments steps 1 through 7 have been invoked:

Determine the amount, location, and type of Supplemental Resources required. Type should be the same kind of resource that is deficient.

Select and move Supplemental Resources from Category (R9) to Categories (R2), (R3), (R4), (R5), and/or (R6) or a least cost basis where least cost equals lowest composite availability, and start-up and minimum generation costs (if start-up is required) are spread over one hour (in cases in which all other factors are equal, the bid energy price will be used as a tie breaker) as follows:

- 1st – Least cost Supplemental Resources available in 10 minutes
- 2nd – Least cost Supplemental Resources available in 30 minutes if additional Supplemental Resources are still needed.
- 3rd – Least cost Supplemental Resources available in greater than 30 minutes if additional Supplemental Resources are still needed.

3. ***Real-Time Energy Deficiency*** – If an energy deficiency (R1) continues (or is expected to continue) to exist in Real-Time even with RTC Resource Adjustments:
   - Determine the amount and location of Supplemental Resources required.
   - Select and move Supplemental Resources from category (R9) to (R1) on a least cost basis where start-up costs (if start-up is required) are spread over one hour as follows:
   - 1st – Least cost Supplemental Resources available in 10 minutes
   - 2nd – Least cost Supplemental Resources available in 30 minutes if additional Supplemental Resources are still needed.
   - 3rd – Least cost Supplemental Resources available in greater than 30 minutes if additional Supplemental Resources are still needed.
4. ***RTC Re-Adjustment*** – Following steps 2 and/or 3 above, subsequent RTC runs may re-adjust resources.

5.7.13 SRE Pricing and Cost Allocations

Energy Payments

Resources committed by SRE will be paid the real time LBMP for Energy and may be guaranteed recovery of start up and minimum generation bid costs ([*]) pursuant to Sections 4.1.7 and 4.10 and Attachment C of the Services Tariff. As previously stated, a resource committed by SRE cannot raise (but may lower) its price bid for the duration of time it was committed.

[*] Bids submitted by generators are subject to conduct and impact testing, and may be mitigated pursuant to the provisions of Attachment H to the Services Tariff. If the Bid has been mitigated, the Bids used to evaluate BPCG eligibility will reflect the mitigation.

Cost Allocation

Assignment of replacement costs that result from a SRE will be as given as shown in Table 5.9.

Table 5.9 Assignment of SRE Replacement Costs

Assignment of SRE Replacement Costs		
Cause for SRE	**Impact of ReplacingEnergy, Operating Reserves and/or Regulation**	**Cost Assignment for Supplemental Payments for Start-Up and Minimum Generation (if any)**
Loss of SCUC Day-Ahead Committed Resource	Charged to Lost Resource	Schedule 1 Uplift
Loss of RTC, RTD-CAM, and/or SRE Committed Resource	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift
Loss of Transmission that Results in Locational Resource Deficiency	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift
Unexpected Load Increase	Affects Real-Time Energy LBMP and/or Marginal Clearing Prices for Ancillary Services	Schedule 1 Uplift

If combustion turbines have an energy or a non-synchronous reserve schedule in the DAM that necessitates the SRE operation of a specific steam unit operated by the turbine owner due to 24-hour NO_X Averaging Period requirements, then the following cost allocation applies:

If the combustion turbines are required for NYISO reliability purposes, the NYISO shall operate the selected steam unit as required via the Supplemental Resource Evaluation (SRE) process. Any real-time uplift costs associated with the operation of the steam unit will be allocated on a statewide basis.

If the combustion turbines are required only for local TO reliability purposes, then the TO shall notify the NYISO of this requirement and the NYISO shall operate the required company steam unit via the SRE process for local TO reliability. Any real-time uplift costs associated with the required steam unit will be allocated to the LSEs in the LBMP zone that had the reliability requirement.

6. DISPATCHING OPERATIONS

This section describes the real-time dispatching operations and covers the following:

- Real-Time Dispatch
- Real-Time Dispatch – Corrective Action
- Dispatching Operations Requirements
- Dispatching Operations Procedures.

6.1 Real-Time Dispatch

Real-Time Dispatch (RTD) is a multi-period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least-as-bid production cost basis. Real-Time Dispatch runs will normally occur every five minutes.

Figure 6-1 presents the RTD time line for a period of one hour.

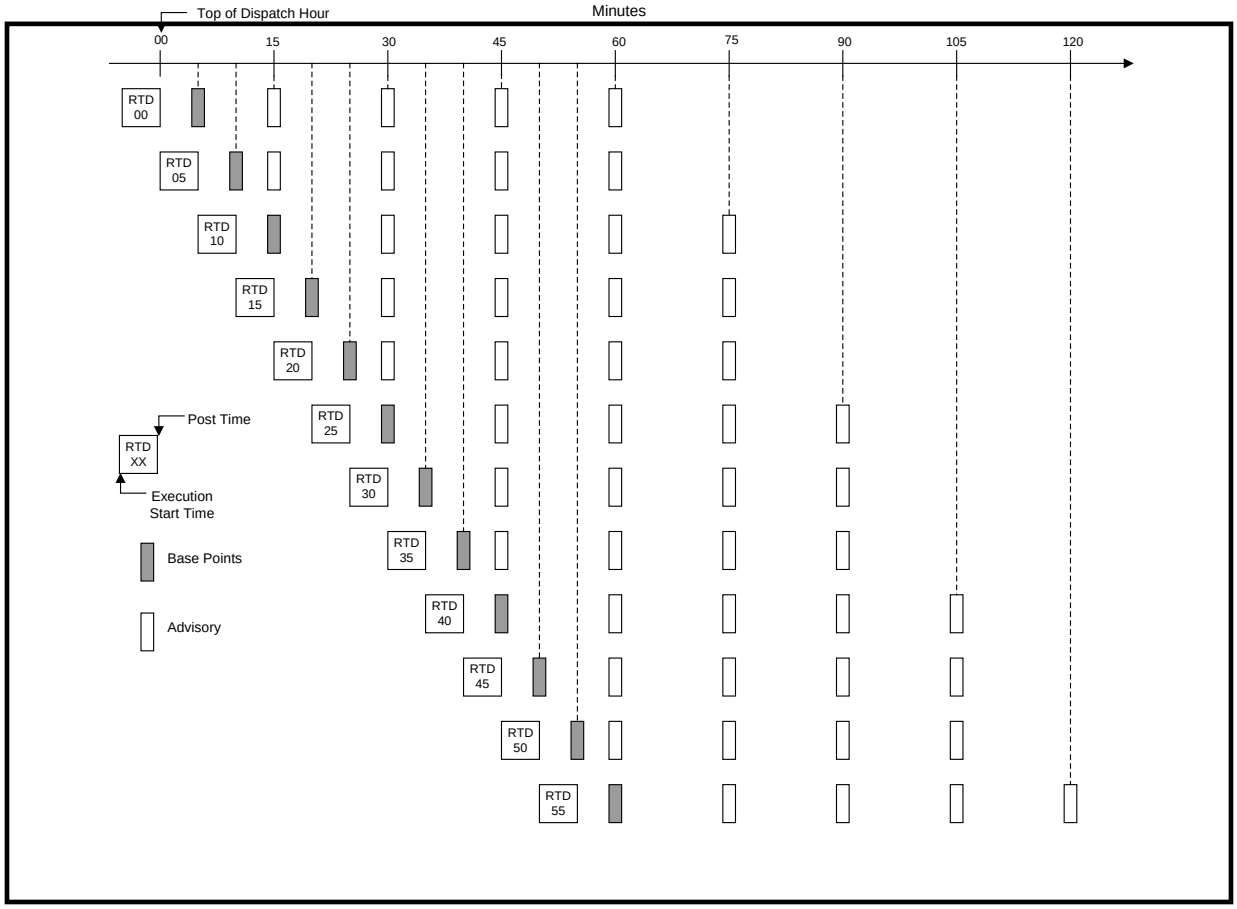

Figure 6-1 Real-Time Dispatch Time Line

6.1.1 Real-Time Dispatch Process

The Real-Time Dispatch will make dispatching decisions, send Base Point Signals to Internal Generators and, to the extent that the NYISO's software can support their participation, Demand Side Resources, calculate Real-Time Market clearing prices for Energy, Operating Reserves, and Real-Time Market Prices for Regulation Service, and establish real-time schedules for those products on a five-minute basis, starting at the beginning of each hour. The Real-Time Dispatch will not make commitment decisions and will not consider start-up costs in any of its dispatching or pricing decisions. Each Real-Time Dispatch run will co-optimize to solve simultaneously for Load, Operating Reserves, and Regulation Service and to minimize the total cost of production over its bid optimization horizon. In addition to producing a binding schedule for the next five minutes, each Real-Time Dispatch run will produce advisory schedules for the remaining four time steps of its bid-optimization horizon. RTD will use the most recent system information and the same set of Bids and constraints that are considered by RTC.

6.1.2 Real-Time Dispatch Information Posting

The public information and secure Market Participant data to be posted from the execution of RTD is described in this subsection.

Public Information

The following information will be produced by RTD and is posted:

1. 5-minute look ahead zonal and generator prices from the first increment of RTD.
2. Ancillary Services prices for the 5-min look-ahead interval of RTD. The following incremental prices are posted:
   - ✧ 10-min Spinning Reserve (West and East)
   - ✧ 10-min Non-Spinning Reserve (West and East)
   - ✧ 30-min Spin/Non-Spin Reserve (West and East)
   - ✧ Regulation Capacity (West and East)
   - ✧ Regulation Movement (NYCA only)
3. The following additional information will be posted as required:
   - ✧ Phase Angle Regulator (PAR) schedules for all PARs
   - ✧ Limiting Constraints on transmission network MW flows (Constraint Type [Base/Contingency] and Shadow Price).
   - ✧ Transmission Interface Flows
4. A set of real-time prices produced by RTD and RTC will also be posted periodically at a NYISO specified time. These prices may be corrected and reposted as required.
5. Zonal and Generator Time Weighted/Integrated LBMP information will be produced by the MIS, using the 5-minute real-time prices, also from the MIS. The time weighted/integrated LBMPs will be posted on an hourly basis within 10-minutes after top-of-hour.

Secure Data to Market Participant

The following information will be produced by RTD and will need to be made available to authorized MPs:

- MW base points for each look-ahead interval of RTD. The first base point from RTD is a 5-minute look-ahead and is immediately passed on to the Automatic Generation Control (AGC) program. The remaining base points are considered to be advisory, and are given at 15-minute intervals.

Market Participants must examine the RTD 15-minute advisory base points to get advance notice of upcoming Unit Startups and Shut Downs. The beginning and end of a Startup period or Shutdown period always occurs at the 15-minute clock times as established by RTC.

> ***Note:*** This does not apply for RTD-CAM functions such as Reserve Pickup Max Gen Pickup and Base Points ASAP- Commit as Necessary.

Startup of quick start units is also communicated via Inter-Control Center Communications Protocol (ICCP) telemetered signals, when scheduled on by RTC, by setting a "startup flag" approximately 15 or 30 minutes ahead, depending on the unit's startup time.

6.2 Real-Time Dispatch – Corrective Action Modes

When the NYISO needs to respond to system conditions that were not anticipated by RTC or the regular Real-Time Dispatch, e.g., the unexpected loss of a major Generator or Transmission line, it will activate the specialized RTD-CAM program. RTD-CAM runs will be nominally either five or ten minutes long, as is described below. Unlike the Real-Time Dispatch, RTD-CAM will have the ability to commit certain Resources. When RTD-CAM is activated, the NYISO will have discretion to implement various measures to restore normal operating conditions. These RTD-CAM measures are described below.

- The NYISO shall have discretion to determine which specific RTD-CAM mode should be activated in particular situations. In addition, RTD-CAM may require all Resources to run above their normal UOLs, up to the level of their emergency UOLs. Self-Scheduled Fixed Resources will not be expected to move in response to RTD-CAM Base Point Signals except when a maximum generation pickup is activated.
- Except as expressly noted in this Section, RTD-CAM will dispatch the system in the same manner as the normal Real-Time Dispatch.
- LESRs will not respond to either reserve or max gen pickups. If it is in the supply mode they will maintain its current output level subject to available energy. If consuming, AGC will set the LESR to zero. RTD-CAM modes will solve assuming a net zero position for LESRs.

6.2.1 Reserve Pickup Mode

The NYISO may enter this RTD-CAM mode when necessary to re-establish schedules if the ACE is greater than 100 MW. When in this mode, RTD-CAM will send 10-minute Base Point Signals and produce schedules for the next ten minutes. RTD-CAM may also commit, or if necessary de-commit, Resources capable of starting or stopping within 10-minutes. The NYISO will continue to optimize for Energy and Operating Reserves, and will recognize locational Operating Reserve requirements, but will set all Regulation Service schedules to zero. If Resources are committed or de-committed in this RTD-CAM mode, the schedules for them will be passed to RTC and the Real-Time Dispatch for their next execution.

The NYISO will have discretion to classify a reserve pickup as a “large event” or a “small event.” In a small event, RTD-CAM may reduce Base Point Signals to reduce transmission line loadings. In a large event, RTD-CAM will not reduce Base Point Signals.

6.2.2 Maximum Generation Pickup

The NYISO will enter this RTD-CAM mode when an Emergency makes it necessary to maximize Energy production in one or more location(s), i.e., Long Island, New York City, East of Total East, and/or NYCA-wide. RTD-CAM will produce schedules directing all

Generators located in a targeted location to increase production at their emergency response rate up to their emergency UOL level and to stay at that level until instructed otherwise. Security constraints will be obeyed to the extent possible. The NYISO will continue to optimize for Energy and Operating Reserves, will recognize locational Operating Reserve requirements, but will set all its Regulation Service schedules to zero.

6.2.3 Base Points ASAP – No Commitments

The NYISO will enter this RTD-CAM mode when changed circumstances make it necessary to issue an updated set of Base Point Signals. Examples of changed circumstances that could necessitate taking this step include correcting line, contingency, or transfer overloads and/or voltage problems caused by unexpected system events. When operating in this mode, RTD-CAM will produce schedules and Base Point Signals for the next five minutes but will only redispatch Generators that are capable of responding within five minutes. RTD-CAM will not commit or de-commit Resources in this mode.

6.2.4 Base Points ASAP – Commit As Needed

This operating mode is identical to Base Points ASAP – No Commitments, except that it also allows the NYISO to commit Generators that are capable of starting within 10 minutes when doing so is necessary to respond to changed system conditions.

6.2.5 Re-Sequencing Mode

When the NYISO is ready to de-activate RTD-CAM, it will often need to transition back to normal Real-Time Dispatch operation. In this mode, RTD-CAM will calculate normal five-minute Base Point Signals and establish five minute schedules. Unlike the normal RTD-Dispatch, however, RTD-CAM will only look ahead 10-minutes. Basepoints issued in the RTD-CAM re-sequencing mode are updated as soon as a normal Real-Time Dispatch run has executed and produced Base Point signals thus completing the transition back to normal RTD execution intervals and optimization horizons.

6.3 RTC/RTD Solution Process

RTC/RTD calculates a short-term generation schedule, referred to as a “base point,” for each of the generating units designated as flexible or “on-dispatch.” RTC/RTD retrieves the information it needs to perform the calculation from data maintained in the NYCA databases. This information includes incremental bid cost curves of the generating units, telemetry data, and other data needed to model each of the constraints.

RTC/RTD determines the initial conditions to begin the commitment and dispatch process. These initial conditions include:

a. Real-time telemetry values for generation output, which represents the initial generation MW values.
b. Forecasted values of zonal, load, and the last RTD powerflow transmission zonal losses.

c. Real-time telemetry values for phase angle regulator flows, which represent their initial power schedule if optimized; otherwise the real-time telemetry represents their final power schedule.
d. Real-Time telemetry values to model unscheduled transmission system powerflows such as Lake Erie Circulation.
e. Current facility outage schedules, including forced and scheduled outages and any outages that affect system transfer limits.
f. For LESRs real-time telemetry of energy storage levels.

RTC/RTD performs a unit commitment and dispatch and a corresponding powerflow solution to ensure that all actual and contingency transmission constraints are secured to applicable limits. Generation delivery factors are calculated from the RTD powerflow solution and are used to approximate the effects of changes in generation on system transmission losses.

If there are unsecured transmission constraints, then RTC/RTD performs additional network constrained unit commitment and dispatch solutions and corresponding powerflow solutions until all actual and contingency transmission constraints are secured.

The allowable dispatch range (maximum and minimum limits) of the dispatchable generating units for the five-minute period are determined considering maximum and minimum limits specified by the Market Participants, regulation constraints, and the response rates of the units.

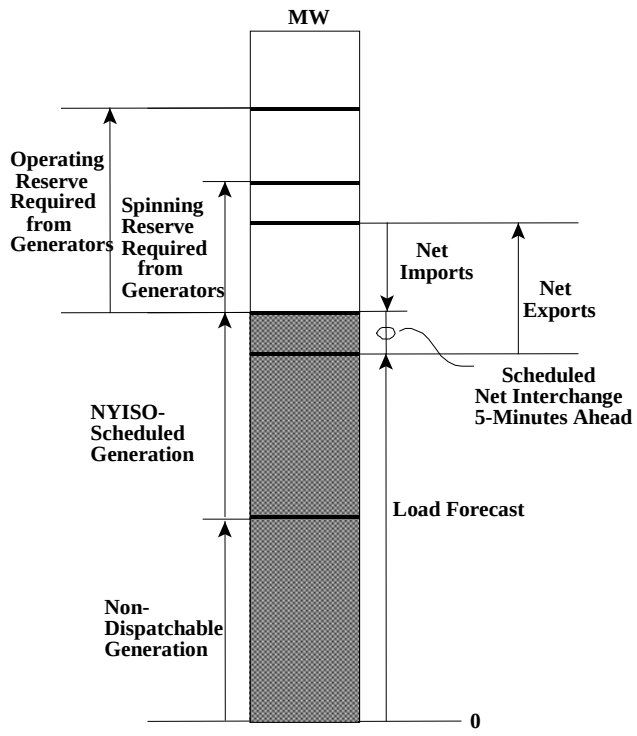

Figure 6-2 Control Area Constraints

6.3.1 Limit Updates

All generator-operating limits are taken from generator bid information. The only changes that are made to unit operating limits are via the OOM package. This is done by a NYISO operator using information received from the TO or the Generator.

At the top of each hour, the real-time upper operating limit will be compared with the projected upper operating limit, which is based on the accepted bid parameters. The OOM limit will be used by RTD. A text alarm will be sent to the TO and to the NYISO alarm screen. Any discrepancy will be resolved with the appropriate generator.

If the unit requires a modification to real-time limits which results in a derating of the unit due to operational problems, the NYISO can lower the upper operating limit. The corresponding RTD high limit will be adjusted.

6.3.2 Status Updates

At the top of each hour, the real-time unit status will be compared with the projected status, which is based on the accepted bid parameters. The unit status will be set from existing real time or projected status, which will be used by RTD and AGC. Additionally:

1. A unit that has not bid for regulation cannot be placed ‘On Control’
2. If a supplier can provide 10-minute non-synchronized reserve but is not scheduled to do so in the DAM and wishes not to be dispatched or started in

real-time by RTD-CAM to provide energy then the supplier must update the real time status to 'unavailable'

3. Suppliers that do not update the limits and or status to equal the projected status or limits as bid and accepted are subject to reserve and regulation balancing payments.

6.3.3 NYISO-TO-Power Supplier Communications

Units that bid such that they will be scheduled at fixed ¼ hour points can obtain their schedules from the MIS posting in addition to the base points that will be transmitted to the TO by the NYISO.

Units that are dispatchable and non-synchronous units that can be committed by RTD-CAM must be prepared to receive real-time schedule changes. The unit schedules (base points) that are sent to the TOs as a result of a reserve pick up or locational reserve pick up will be tagged to indicate that the base points were calculated based on the higher of normal or emergency response criteria. This is an indication that the dispatchable and Non-synchronous units may be receiving a RTD-CAM schedule change and that the base points may reflect emergency response rate criteria.

6.3.4 Transmission loss treatment

The day-ahead and real-time scheduling programs each employ the same treatment of physical transmission losses. The day-ahead software is the Security-Constrained Unit Commitment (SCUC) program, and the real-time software is the Real-Time Commitment (RTC) and Real-time Dispatch (RTD) programs. Transmission losses are calculated as part of the power flow solution for each time interval simulated by these programs for each of the eleven load zones in the NYCA.

The short-term real-time load forecast provides a forecast of the eleven zonal loads for each interval. The load forecast does not include an estimate of zonal transmission losses. The loss estimates for the load zones are determined from the network power flow solutions of the corresponding RTC/RTD intervals. The load forecast for the real-time market operation is determined for demand only and the calculation of losses within RTC and RTD are added to the forecast for total scheduling or dispatching requirements. Generating resources and external import transactions are scheduled in RTC/RTD to meet (i) the forecast of the zonal loads and (ii) the RTC/RTD zonal loss determinations and external export transactions.

6.3.5 Phase Shifter Models

The RTC/RTD programs assume that the pre-contingency active power flows on phase shifter controlled transmission lines are fixed at their telemetered values observed at the start of the dispatch interval except for those PARs listed below, i.e., phase shifter controlled lines are said to be "block loaded". However, for contingency case security constraints, the post-contingency flows on phase shifter controlled lines varies as a function of the pre-contingency values of the facilities described in the contingency and forecast system topology. For contingency analysis, phase shifter controlled lines are said to be allowed to "free-flow."

The desired flows will be established for the ABC, JK, 5018 and 1385 interconnections based on the following

- the ABC interconnection will be the current level of ABC power flows (based on PAR MW telemetry values) plus 0% (13% prior to May 1,2012) of the expected schedule changes to the PJM-NYISO interchange
- the JK interconnection will be the current level of JK power flows (based on PAR MW telemetry values) plus 0% (-13% prior to May 1,2012) of the expected schedule changes to the PJM-NYISO interchange
- the Hopatcong-Ramapo interconnection will be the current level of 5018 power flows (based on PAR MW telemetry values) plus 40% of the expected schedule changes to the PJM-NYISO interchange. The Hopatcong-Ramapo 500kV Operating agreement allows for the assumption that up to 61% of PJM-NY transaction schedules at the Keystone Proxy Bus flow over the 5018 interconnection. However, flows over the 5018 interconnection will be conservatively modeled at 40% to ensure feasible operating schedules.
- the 1385 Northport-Norwalk Harbor interconnection will be determined by transaction bid evaluation on the NPX 1385 proxy bus.

6.3.6 Demand curves

The unit commitment and dispatch module used in both the SCUC and RTS systems was given additional functionality of demand curves. The demand curve allows the program to relax the requirements if the shadow cost needed to supply the requirement exceeds a preset value. The demand curve functionality is used for the reserve and regulation requirements and for transmission constraints. The demand curves shown in Table 6.1 are implemented:

Table 6.1 Demand Curves

Type	NY Region	Demand Curve (MW)	Demand Curve Price ($)
Regulation*	NYCA	25.0 80.0 remainder	$80.00 $180.00 $400.00
Spinning Reserve	NYCA	All	$500.00
10 Minute Reserve	NYCA	All	$450.00
30 Minute Reserve	NYCA	200.0 400.0 remainder	$50.00 $100.00 $200.00

Type	NY Region	Demand Curve (MW)	Demand Curve Price ($)
Spinning Reserve	Eastern NY	All	$25.00
10 Minute Reserve	Eastern NY	All	$500.00
30 Minute Reserve	Eastern NY	All	$25.00
Spinning Reserve	Long Island	All	$25.00
10 Minute Reserve	Long Island	All	$25.00
30 Minute Reserve	Long Island	All	$25.00
Transmission	All	All	$4000.00

* If the Regulation Demand Curve is active, RTD will not set basepoints for LESR energy management.

6.3.7 Locational Reserves

Operating reserves will be locationally priced and the locational reserve requirements will be determined by the NYISO. There are locational reserve requirements for the NYCA, the Eastern New York area, and the Long Island area.

Reserves are scheduled as part of each RTD run and are co-optimized, nominally every five minutes, along with energy and regulation schedules. These reserves may be converted to energy in any normal dispatch or during a Reserve Pickup and replacement reserves scheduled on other available resources. During a reserve pickup event, dispatchable suppliers will be dispatched upward at the higher of their normal response rate curve or their emergency response rates. During a Reserve Pickup, the NYISO will notify the TOs, who in turn will notify dispatchable resources that a Reserve Pickup is taking place. A RPU “flag” will be sent with the basepoints via ICCP.

With respect to 30-minute Reserves, Reserve Pickup will dispatch 30-minute Spinning Reserve Upward but not 30-minute non-synchronized Reserve. This would be done at the next RTC execution or through a Supplemental Resource Evaluation (SRE).

6.3.8 Reserve Comparator

The Reserve Comparator (RC) function executes nominally every five minutes and resides on the on-line EMS to track actual system reserves and system reserve requirements. The purpose of the RC program is to monitor the locational reserves and capability in the real time system and for interchange evaluation in the NYCA. RC monitors NYCA reserves in

three categories: 10-minute synchronous reserve, total 10-minute reserve, and total 30-minute reserve. Currently it also calculates the reserves and capability from units and transactions for each Zone and the NYCA.

6.3.9 Reserve Calculations

The following reserve calculations are implemented for the LBMP Market:

1. Reserves are calculated on a locational basis.
2. There are reserve requirements for each of the locational reserve areas with the appropriate alarming.
3. Non-synchronous reserve can only be counted on units that have an accepted bid and have been committed for non-synchronous reserve. This applies for both 10-minute and Operating Reserve.

All dispatchable (on-line) units are counted towards 10-minute synchronous reserve, whether or not they have an accepted reserve availability bid.

6.3.10 Simultaneous Activation of Reserves

The Simultaneous Activation of Reserves (SAR) is a mutual agreement among the following participating areas to provide 10-minute reserve assistance:

- Ontario
- New England/New Brunswick
- NYISO
- PJM

The NYISO acts as the central coordinator for the SAR procedure and will ensure that SAR allocations assigned to the participating areas are within their response capabilities. The SAR allocation for an area is the additional amount of energy it is assigned to provide in response to a SAR request.

Procedure

The following is a summary of the SAR procedure, which is described in greater detail in the the NPCC Regional Reliability Directory#5 Section 5.8 and Appendix#4 (December 2, 2010).

1. ***Preliminary Reserve Assignment:*** On a continuing basis, Maritimes, ISO-NE, Ontario, and PJM dispatchers shall keep the NYISO informed of the largest, single generation or energy purchase contingency on their respective system and changes thereof.

   Information pertaining to an Area's inability to participate, reserve limitations (such as "bottled" reserve or reserves used to deliver economy energy sales) and transmission limitations shall be reported to Maritimes, ISO-NE, Ontario, and PJM by the NYISO Shift Supervisor as those conditions arise.
2. ***Notification of Contingency:*** Immediately following a sudden loss of generation or energy purchase in the Maritimes, ISO-NE, NYISO, Ontario, or

PJM, the Area experiencing the loss (Contingency Area) shall indicate whether SAR is being requested and report the following information to the NYISO via the interregional direct telephone lines:

- ✧ Name of generation or purchase lost.
- ✧ Total number of megawatts lost.
- ✧ Time that contingency occurred (time zero T+0).
- ✧ Any transmission or security problems within the Contingency Area that affect SAR allocations to Assisting Areas.

3. ***Activation of Reserve:*** After receiving notification of the SAR request and the specific contingency, the NYISO Shift Supervisor shall:
   - ✧ Determine each Area's SAR allocation in accordance with NPCC Procedure C-12.
   - ✧ By the direct inter-Area telephone lines, immediately inform each Area of its SAR allocation, the time that the schedule change is effective, and the time that the contingency occurred.

The SAR allocation shall become part of the interchange schedule and shall be implemented immediately following notification.

4. ***Provision of Reserve Assistance:*** Assisting Areas shall respond as quickly as possible, assuming the same obligation as if the contingency occurred within its Area. Assisting Areas shall complete a report that documents the Reserve Assistance provided.

The Contingency Area shall initiate immediate action to provide its share of reserve to recover from the generation or energy purchase loss, prepare for the replacement of the reserve assistance assigned to assisting Areas, and proceed to re-establish 10-minute reserve at least equal to its next largest contingency.

5. ***Termination of Simultaneous Reserve:*** As soon as the Contingency Area has provided its SAR allocation, it will notify the NYISO. The NYISO shall establish a conference call between all participating Areas and confirm the time that the assistance shall be terminated. Revised interchange schedules will be mutually established as required to ensure that the Assisting Areas properly recall assistance. The Contingency Area shall replace the reserve assistance assigned to assisting Areas in a manner consistent with mutually established interchange schedules.

In the event that a Contingency Area is not prepared to replace the remaining portion of its reserve obligation within time zero + 30 minutes, the Contingency Area shall arrange for additional assistance in accordance with applicable policies and agreements covering interchange and emergency assistance.

In the event that the security of an Assisting Area becomes jeopardized, that Area may cancel all or part of its allocation by notifying the NYISO, which will then request the Contingency Area to pick up the required additional amounts of reserve. The Contingency Area shall complete a report that documents the recovery provided for the contingency.

6. ***Subsequent Contingencies:*** In the event that a subsequent loss of generation or energy purchase, regardless of the size of the contingency, occurs during the

period when a reserve pick-up is in progress, the second Contingency Area may, at its discretion, withdraw assistance and request the NYISO to reallocate the assistance in accordance with the provisions of this simultaneous activation of reserve procedure.

Upon such notification, the NYISO will notify the first Contingency Area of the amount of withdrawal. Both Contingency Areas will immediately enter new interchange schedules that reflect the loss of the assistance, using a zero time ramp.

In the event that the second Contingency Area experiences a contingency that qualifies for simultaneous activation of reserve, the NYISO will allocate assistance from the remaining Assisting Areas in accordance with this procedure, upon the request of that Area.

If the second contingency occurs in the Area that has incurred the first contingency, that Area may request assistance, in accordance with this procedure, regardless of the size of the contingency.

7. ***Disturbance Control Standard (DCS) Reporting of Simultaneous Activation Reserve Events:*** The evaluation of DCS compliance for an Area shall utilize the NERC Disturbance Recovery Period applicable at the time of the reportable event (15 minutes). The evaluation of compliance for the purpose of determining Area synchronized reserve requirements shall utilize a recovery period established by the NPCC (15 minutes).

NYISO Operator Action

The NYISO Operator interacts with SAR as follows:

1. The NYISO Operator calls up the SAR display and enters the following information:
   - ✧ Neighboring SAR area
   - ✧ MW amount of SAR
   - ✧ Activation (Immediate) or Termination (Immediate or Scheduled Time)
2. When a SAR is activated, the SAR MW value shall immediately take on the Operator entered SAR MW amount, regardless of any existing SAR value or if termination was already in progress,
3. When a SAR is terminated, the current (or scheduled) SAR value shall be ramped to zero over a 10-minute period, even if termination was already in progress.
4. SAR MW values are automatically converted to 1-minute values for input to the RTD/RTD-CAM and AGC programs.
   - ✧ RTC will not have a direct SAR MW input.
   - ✧ AGC will record the application of the SAR MW inputs.

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Attachment A. Transmission Facilities

- Table A.1 lists NYISO Facilities Requiring Coordination and Notification.
- Table A.2 lists Bus Voltage Limits for NYISO Secured Transmission System.
- Table A.3 lists Bus Voltage Limits for HQ-NYISO transfers.

Table A.1 NYISO Facilities Requiring Coordination and Notification

The NYISO Facilities Requiring Coordination and Notification can be found in the Outage Scheduling Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

Table A.2 Bus Voltage Limits for NYISO Secured Transmission System

The Bus Voltage Limits for NYISO Secured Transmission system can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp)

Table A.3 Bus Voltage Limits for HQ-NYISO Transfers

The Bus Voltage Limits for HQ-NYISO Transfers can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp)

Attachment B. Operating Criteria

- Table B.1 lists exceptions to operating criteria for pre-contingency and post-contingency transmission facility flows and voltages.
- Table B.2 lists multiple circuit tower lines in the NYCA [MP 29-1, A].
- Table B.3 lists the NYISO thunderstorm multiple contingencies [MP 29-1, B].
- Table B.4 lists the local reliability rules of the New York Transmission Owners.
- Table B.5 displays the applications of reliability rules and cost allocation responsibility.

Table B.1 Exceptions to the NYSRC Reliability Rules

The exceptions to the NYSRC Reliability Rules are approved by the NYSRC. The current set of exception can be found at:

http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.html

Table B.2 Multiple Circuit Tower Lines in NY Control Area

The Multiple Circuit Tower Lines in the NY Control Area can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp).

Table B.3 Thunderstorm Multiple Contingencies Cases

The Thunderstorm Multiple Contingencies Cases can be found in the Emergency Operations Manual (available from the NYISO Web site at the following URL: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp)

Table B.4 Local Reliability Rules of the New York Transmission Owners

The Local Reliability Rules are more stringent than the other NYSRC Reliability Rules because of the need to protect delivery in certain zones. The current set of Local Reliability Rules can be found in Section I of the NYSRC Reliability Rules Manual at:

http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.html

Table B.5 Applications of Reliability Rules and Cost Allocation Responsibility

The current version of the ARR Table is posted at:

http://www.nyiso.com/public/webdocs/market_data/reports_info/TO_Application_of_Reliability_Rules.pdf

Attachment C. [This Attachment intentionally left blank]

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Attachment D. Generating Unit AVR / PSS Status Log

This form is used by the NYISO to record the status of Automatic Voltage Regulators and Power System Stabilizers in the New York Control Area.

Unit Name & Identification	Out-of-Service Date Time	Return-to-Service Date Time

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Rochester Gas and Electric Corporation

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant
Case 14-E-0270

INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.2)

Request No.: GNP-15-207

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

RG&E Historical Peak Loads

1) For each of the years 2010 through 2015, provide historical RG&E summer and winter non-coincident peak loads – both actual and weather normalized.

Response:

RGE Non-Coincident Summer Peaks						
	2010	2011	2012	2013	2014	2015
RGE Actual Peak (Summer)	1,649	1,752	1,666	1,685	1,508	1,535
RGE Peak - Weather Normalized - (Median THI)	1,607	1,597	1,639	1,575	1,614	1,549
RGE Peak - Weather Normalized - (10th percentile THI)	1,520	1,484	1,491	1,412	1,465	1,405
RGE Peak - Weather Normalized - (90th percentile THI)	1,673	1,693	1,768	1,719	1,775	1,684
THI= Temperature-Humidity Index						
Losses are included						

RGE Non-Coincident Winter Peaks						
	2010	2011	2012	2013	2014	2015
RGE Actual Peak (Winter)	1,186	1,208	1,152	1,177	1,231	1,192
RGE Peak - Weather Normalized - (Median HDD)	1,231	1,243	1,152	1,176	1,201	1,188
RGE Peak - Weather Normalized - (10th percentile HDD)	1,183	1,200	1,111	1,137	1,157	1,147
RGE Peak - Weather Normalized - (90th percentile HDD)	1,262	1,270	1,178	1,200	1,229	1,220
HDD= Heating Degree Day Index						
Losses are included						

Rochester Gas and Electric Corporation

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant
Case 14-E-0270

INFORMATION REQUEST

2) Provide an estimate of the RG&E non-coincident summer and winter peak loads as a percentage of the NYISO Load Zone B non-coincident summer and winter peak loads respectively.

Response:

RGE Share of Zone B Non-Coincident Peak Load						
	2010	2011	2012	2013	2014	2015
Summer	79.5%	79.7%	78.8%	80.1%	79.5%	N/A
Winter	74.9%	75.2%	74.7%	73.8%	74.4%	73.2%
2015 NYISO Summer Non-Coincident Peak Demand by Zone not yet published.						

3) Provide an estimate of the Rochester Area non-coincident summer and winter peak loads as a percentage of the NYISO Load Zone B non-coincident summer and winter peak loads respectively.

Response:

Rochester Area Share of Zone B Non-Coincident Peak Load						
	2010	2011	2012	2013	2014	2015
Summer	66.78%	66.95%	66.19%	67.28%	66.78%	N/A
Winter	62.92%	63.17%	62.75%	61.99%	62.50%	61.49%

Rochester Gas and Electric Corporation

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant
Case 14-E-0270

INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.3)

Request No.: GNP-15-208

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

RG&E Powers Factors

1) Provide RG&E historical summer and winter peak load power factors (net system power factors after correction using reactive resources); also specifying the year associated with each.

2) To the extent RG&E power factors are anticipated to change materially in the future, provide an estimate of future expected RG&E summer and winter peak load power factors (net system power factors after correction using reactive resources); also specifying the year associated with each.

Response:

RG&E does not have load power factor or reactive power data sufficient to reflect an overall system power factor, either current or historical.

Rochester Gas and Electric Corporation

Petition for Initiation of a Proceeding to Examine a Proposal for Continued Operation of the R.E. Ginna Nuclear Power Plant
Case 14-E-0270

INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.4)

Request No.: GNP-15-209

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

RG&E Hourly Load Tabulation

For all hours in the year 2013, provide a tabulated chart of actual hourly RG&E MW loads including associated dates and times.

Response:

See the Attachment 1.

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	1	1	740.828
2013	1	1	2	703.728
2013	1	1	3	680.161
2013	1	1	4	664.143
2013	1	1	5	668.778
2013	1	1	6	684.009
2013	1	1	7	708.436
2013	1	1	8	728.926
2013	1	1	9	741.792
2013	1	1	10	784.108
2013	1	1	11	818.504
2013	1	1	12	840.339
2013	1	1	13	852.073
2013	1	1	14	840.015
2013	1	1	15	840.772
2013	1	1	16	846.860
2013	1	1	17	893.395
2013	1	1	18	1,006.408
2013	1	1	19	1,010.198
2013	1	1	20	993.375
2013	1	1	21	967.082
2013	1	1	22	913.838
2013	1	1	23	852.771
2013	1	1	24	792.534
2013	1	2	1	756.590
2013	1	2	2	733.992
2013	1	2	3	728.225
2013	1	2	4	725.762
2013	1	2	5	747.550
2013	1	2	6	802.128
2013	1	2	7	913.229
2013	1	2	8	979.284
2013	1	2	9	982.915
2013	1	2	10	998.132
2013	1	2	11	1,001.416
2013	1	2	12	1,022.694
2013	1	2	13	1,020.644
2013	1	2	14	1,019.123
2013	1	2	15	1,015.825
2013	1	2	16	1,014.827
2013	1	2	17	1,057.117
2013	1	2	18	1,129.662
2013	1	2	19	1,132.994
2013	1	2	20	1,108.460
2013	1	2	21	1,072.572
2013	1	2	22	1,010.971
2013	1	2	23	920.422
2013	1	2	24	853.776
2013	1	3	1	807.725
2013	1	3	2	781.850

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	3	3	766.290
2013	1	3	4	769.285
2013	1	3	5	785.256
2013	1	3	6	838.929
2013	1	3	7	934.470
2013	1	3	8	1,002.201
2013	1	3	9	1,004.867
2013	1	3	10	1,008.654
2013	1	3	11	1,018.347
2013	1	3	12	1,018.488
2013	1	3	13	1,014.643
2013	1	3	14	1,008.060
2013	1	3	15	1,003.141
2013	1	3	16	999.035
2013	1	3	17	1,036.039
2013	1	3	18	1,116.006
2013	1	3	19	1,106.608
2013	1	3	20	1,080.092
2013	1	3	21	1,050.368
2013	1	3	22	987.332
2013	1	3	23	906.672
2013	1	3	24	837.483
2013	1	4	1	793.105
2013	1	4	2	769.873
2013	1	4	3	758.896
2013	1	4	4	753.843
2013	1	4	5	770.316
2013	1	4	6	821.223
2013	1	4	7	917.165
2013	1	4	8	977.409
2013	1	4	9	981.644
2013	1	4	10	991.640
2013	1	4	11	1,005.887
2013	1	4	12	1,002.873
2013	1	4	13	999.081
2013	1	4	14	989.962
2013	1	4	15	965.887
2013	1	4	16	966.967
2013	1	4	17	997.180
2013	1	4	18	1,066.290
2013	1	4	19	1,058.395
2013	1	4	20	1,034.463
2013	1	4	21	1,013.769
2013	1	4	22	964.142
2013	1	4	23	893.436
2013	1	4	24	828.072
2013	1	5	1	765.998
2013	1	5	2	740.558
2013	1	5	3	724.200
2013	1	5	4	720.281

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	5	5	722.283
2013	1	5	6	737.718
2013	1	5	7	780.213
2013	1	5	8	807.655
2013	1	5	9	836.530
2013	1	5	10	868.092
2013	1	5	11	885.058
2013	1	5	12	889.390
2013	1	5	13	874.855
2013	1	5	14	868.658
2013	1	5	15	860.536
2013	1	5	16	865.325
2013	1	5	17	907.989
2013	1	5	18	985.944
2013	1	5	19	989.264
2013	1	5	20	962.452
2013	1	5	21	939.667
2013	1	5	22	897.791
2013	1	5	23	847.831
2013	1	5	24	788.461
2013	1	6	1	739.706
2013	1	6	2	710.236
2013	1	6	3	686.408
2013	1	6	4	682.623
2013	1	6	5	684.262
2013	1	6	6	693.191
2013	1	6	7	719.683
2013	1	6	8	745.127
2013	1	6	9	767.452
2013	1	6	10	793.692
2013	1	6	11	820.235
2013	1	6	12	842.290
2013	1	6	13	846.957
2013	1	6	14	854.747
2013	1	6	15	853.370
2013	1	6	16	863.393
2013	1	6	17	910.795
2013	1	6	18	996.286
2013	1	6	19	989.398
2013	1	6	20	962.577
2013	1	6	21	935.495
2013	1	6	22	882.504
2013	1	6	23	823.399
2013	1	6	24	764.984
2013	1	7	1	726.527
2013	1	7	2	704.490
2013	1	7	3	697.612
2013	1	7	4	704.787
2013	1	7	5	723.555
2013	1	7	6	790.289

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	7	7	887.580
2013	1	7	8	963.149
2013	1	7	9	971.476
2013	1	7	10	974.937
2013	1	7	11	991.381
2013	1	7	12	992.980
2013	1	7	13	985.445
2013	1	7	14	972.319
2013	1	7	15	975.830
2013	1	7	16	970.778
2013	1	7	17	994.237
2013	1	7	18	1,078.777
2013	1	7	19	1,080.928
2013	1	7	20	1,053.057
2013	1	7	21	1,020.324
2013	1	7	22	965.127
2013	1	7	23	894.403
2013	1	7	24	826.034
2013	1	8	1	777.870
2013	1	8	2	756.052
2013	1	8	3	740.333
2013	1	8	4	737.477
2013	1	8	5	753.486
2013	1	8	6	811.574
2013	1	8	7	909.000
2013	1	8	8	967.143
2013	1	8	9	960.992
2013	1	8	10	967.705
2013	1	8	11	968.198
2013	1	8	12	969.353
2013	1	8	13	954.500
2013	1	8	14	951.307
2013	1	8	15	936.294
2013	1	8	16	939.251
2013	1	8	17	970.763
2013	1	8	18	1,058.569
2013	1	8	19	1,063.480
2013	1	8	20	1,045.057
2013	1	8	21	1,008.227
2013	1	8	22	953.647
2013	1	8	23	870.556
2013	1	8	24	809.099
2013	1	9	1	762.974
2013	1	9	2	741.858
2013	1	9	3	729.656
2013	1	9	4	728.577
2013	1	9	5	743.474
2013	1	9	6	801.967
2013	1	9	7	899.740
2013	1	9	8	961.278

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	9	9	961.535
2013	1	9	10	977.013
2013	1	9	11	988.154
2013	1	9	12	980.178
2013	1	9	13	951.733
2013	1	9	14	942.038
2013	1	9	15	937.474
2013	1	9	16	930.057
2013	1	9	17	958.230
2013	1	9	18	1,050.419
2013	1	9	19	1,054.077
2013	1	9	20	1,031.348
2013	1	9	21	995.931
2013	1	9	22	940.952
2013	1	9	23	861.813
2013	1	9	24	799.082
2013	1	10	1	748.592
2013	1	10	2	727.943
2013	1	10	3	717.884
2013	1	10	4	712.770
2013	1	10	5	727.452
2013	1	10	6	785.381
2013	1	10	7	888.429
2013	1	10	8	947.486
2013	1	10	9	942.096
2013	1	10	10	947.029
2013	1	10	11	956.011
2013	1	10	12	942.811
2013	1	10	13	931.653
2013	1	10	14	925.752
2013	1	10	15	921.905
2013	1	10	16	915.408
2013	1	10	17	943.613
2013	1	10	18	1,038.983
2013	1	10	19	1,043.668
2013	1	10	20	1,019.785
2013	1	10	21	985.771
2013	1	10	22	928.696
2013	1	10	23	857.122
2013	1	10	24	790.566
2013	1	11	1	749.311
2013	1	11	2	725.960
2013	1	11	3	706.721
2013	1	11	4	705.583
2013	1	11	5	719.257
2013	1	11	6	779.004
2013	1	11	7	868.271
2013	1	11	8	933.134
2013	1	11	9	943.204
2013	1	11	10	955.047

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	11	11	962.011
2013	1	11	12	957.036
2013	1	11	13	951.370
2013	1	11	14	945.688
2013	1	11	15	939.627
2013	1	11	16	944.679
2013	1	11	17	959.631
2013	1	11	18	1,009.758
2013	1	11	19	996.135
2013	1	11	20	965.651
2013	1	11	21	930.875
2013	1	11	22	888.864
2013	1	11	23	820.376
2013	1	11	24	766.857
2013	1	12	1	711.371
2013	1	12	2	681.229
2013	1	12	3	664.037
2013	1	12	4	657.055
2013	1	12	5	661.939
2013	1	12	6	677.891
2013	1	12	7	717.828
2013	1	12	8	763.120
2013	1	12	9	785.441
2013	1	12	10	812.322
2013	1	12	11	826.669
2013	1	12	12	833.893
2013	1	12	13	822.317
2013	1	12	14	815.719
2013	1	12	15	804.654
2013	1	12	16	799.288
2013	1	12	17	833.650
2013	1	12	18	909.764
2013	1	12	19	915.843
2013	1	12	20	889.375
2013	1	12	21	863.493
2013	1	12	22	827.227
2013	1	12	23	775.669
2013	1	12	24	721.075
2013	1	13	1	674.913
2013	1	13	2	643.081
2013	1	13	3	620.975
2013	1	13	4	619.953
2013	1	13	5	613.258
2013	1	13	6	630.963
2013	1	13	7	653.323
2013	1	13	8	687.635
2013	1	13	9	710.228
2013	1	13	10	737.893
2013	1	13	11	766.075
2013	1	13	12	783.282

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	13	13	786.705
2013	1	13	14	790.894
2013	1	13	15	787.176
2013	1	13	16	803.049
2013	1	13	17	845.406
2013	1	13	18	921.226
2013	1	13	19	916.399
2013	1	13	20	886.790
2013	1	13	21	858.173
2013	1	13	22	807.550
2013	1	13	23	751.375
2013	1	13	24	699.372
2013	1	14	1	656.496
2013	1	14	2	634.965
2013	1	14	3	633.752
2013	1	14	4	635.342
2013	1	14	5	650.966
2013	1	14	6	711.807
2013	1	14	7	826.158
2013	1	14	8	900.040
2013	1	14	9	912.451
2013	1	14	10	927.161
2013	1	14	11	951.984
2013	1	14	12	959.955
2013	1	14	13	962.374
2013	1	14	14	962.274
2013	1	14	15	958.987
2013	1	14	16	962.495
2013	1	14	17	999.506
2013	1	14	18	1,066.605
2013	1	14	19	1,063.653
2013	1	14	20	1,036.030
2013	1	14	21	1,001.120
2013	1	14	22	941.114
2013	1	14	23	863.378
2013	1	14	24	798.016
2013	1	15	1	758.648
2013	1	15	2	734.337
2013	1	15	3	725.063
2013	1	15	4	722.327
2013	1	15	5	738.595
2013	1	15	6	799.591
2013	1	15	7	900.928
2013	1	15	8	970.094
2013	1	15	9	976.658
2013	1	15	10	975.981
2013	1	15	11	990.875
2013	1	15	12	985.332
2013	1	15	13	980.032
2013	1	15	14	967.157

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	15	15	958.727
2013	1	15	16	949.801
2013	1	15	17	982.862
2013	1	15	18	1,065.345
2013	1	15	19	1,071.032
2013	1	15	20	1,044.364
2013	1	15	21	1,009.947
2013	1	15	22	949.606
2013	1	15	23	867.381
2013	1	15	24	807.481
2013	1	16	1	763.365
2013	1	16	2	738.753
2013	1	16	3	725.517
2013	1	16	4	722.144
2013	1	16	5	736.739
2013	1	16	6	797.587
2013	1	16	7	895.820
2013	1	16	8	971.663
2013	1	16	9	978.581
2013	1	16	10	987.481
2013	1	16	11	1,000.734
2013	1	16	12	993.572
2013	1	16	13	993.918
2013	1	16	14	976.588
2013	1	16	15	958.084
2013	1	16	16	947.305
2013	1	16	17	971.477
2013	1	16	18	1,049.304
2013	1	16	19	1,058.668
2013	1	16	20	1,030.889
2013	1	16	21	1,004.407
2013	1	16	22	943.055
2013	1	16	23	862.988
2013	1	16	24	803.391
2013	1	17	1	755.363
2013	1	17	2	734.090
2013	1	17	3	722.444
2013	1	17	4	714.736
2013	1	17	5	733.397
2013	1	17	6	793.190
2013	1	17	7	885.993
2013	1	17	8	970.772
2013	1	17	9	984.703
2013	1	17	10	998.129
2013	1	17	11	1,010.826
2013	1	17	12	1,017.950
2013	1	17	13	1,020.204
2013	1	17	14	1,020.144
2013	1	17	15	1,014.187
2013	1	17	16	1,013.279

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	17	17	1,044.711
2013	1	17	18	1,099.730
2013	1	17	19	1,098.900
2013	1	17	20	1,068.978
2013	1	17	21	1,037.447
2013	1	17	22	982.845
2013	1	17	23	903.376
2013	1	17	24	840.554
2013	1	18	1	796.569
2013	1	18	2	768.844
2013	1	18	3	758.785
2013	1	18	4	755.659
2013	1	18	5	771.905
2013	1	18	6	830.269
2013	1	18	7	931.974
2013	1	18	8	990.027
2013	1	18	9	995.258
2013	1	18	10	999.849
2013	1	18	11	1,000.886
2013	1	18	12	998.477
2013	1	18	13	989.032
2013	1	18	14	982.251
2013	1	18	15	969.322
2013	1	18	16	963.542
2013	1	18	17	986.352
2013	1	18	18	1,046.730
2013	1	18	19	1,042.853
2013	1	18	20	1,015.113
2013	1	18	21	990.162
2013	1	18	22	945.767
2013	1	18	23	880.189
2013	1	18	24	810.862
2013	1	19	1	758.507
2013	1	19	2	732.040
2013	1	19	3	712.845
2013	1	19	4	705.299
2013	1	19	5	701.003
2013	1	19	6	720.013
2013	1	19	7	759.173
2013	1	19	8	799.678
2013	1	19	9	817.255
2013	1	19	10	847.614
2013	1	19	11	868.967
2013	1	19	12	868.629
2013	1	19	13	846.981
2013	1	19	14	842.502
2013	1	19	15	833.607
2013	1	19	16	832.713
2013	1	19	17	855.348
2013	1	19	18	930.179

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	19	19	931.479
2013	1	19	20	903.674
2013	1	19	21	885.135
2013	1	19	22	841.586
2013	1	19	23	792.269
2013	1	19	24	737.173
2013	1	20	1	693.231
2013	1	20	2	667.417
2013	1	20	3	648.627
2013	1	20	4	641.672
2013	1	20	5	643.414
2013	1	20	6	662.597
2013	1	20	7	691.973
2013	1	20	8	730.631
2013	1	20	9	755.171
2013	1	20	10	808.873
2013	1	20	11	828.256
2013	1	20	12	843.185
2013	1	20	13	869.312
2013	1	20	14	874.518
2013	1	20	15	884.510
2013	1	20	16	896.832
2013	1	20	17	922.177
2013	1	20	18	1,000.521
2013	1	20	19	1,004.479
2013	1	20	20	984.548
2013	1	20	21	959.900
2013	1	20	22	920.686
2013	1	20	23	865.236
2013	1	20	24	814.637
2013	1	21	1	774.570
2013	1	21	2	754.842
2013	1	21	3	744.650
2013	1	21	4	740.542
2013	1	21	5	756.867
2013	1	21	6	807.275
2013	1	21	7	873.511
2013	1	21	8	942.285
2013	1	21	9	970.449
2013	1	21	10	999.926
2013	1	21	11	1,025.113
2013	1	21	12	1,027.030
2013	1	21	13	1,026.765
2013	1	21	14	1,020.327
2013	1	21	15	1,020.162
2013	1	21	16	1,012.046
2013	1	21	17	1,018.007
2013	1	21	18	1,091.258
2013	1	21	19	1,100.315
2013	1	21	20	1,079.326

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	21	21	1,047.968
2013	1	21	22	990.309
2013	1	21	23	922.362
2013	1	21	24	857.182
2013	1	22	1	818.597
2013	1	22	2	795.143
2013	1	22	3	785.116
2013	1	22	4	787.890
2013	1	22	5	807.729
2013	1	22	6	868.143
2013	1	22	7	978.539
2013	1	22	8	1,044.100
2013	1	22	9	1,049.444
2013	1	22	10	1,059.636
2013	1	22	11	1,071.800
2013	1	22	12	1,080.747
2013	1	22	13	1,071.262
2013	1	22	14	1,069.105
2013	1	22	15	1,053.933
2013	1	22	16	1,056.471
2013	1	22	17	1,084.553
2013	1	22	18	1,160.920
2013	1	22	19	1,171.920
2013	1	22	20	1,146.059
2013	1	22	21	1,105.545
2013	1	22	22	1,042.468
2013	1	22	23	962.648
2013	1	22	24	895.720
2013	1	23	1	850.054
2013	1	23	2	827.098
2013	1	23	3	812.139
2013	1	23	4	815.049
2013	1	23	5	826.769
2013	1	23	6	888.429
2013	1	23	7	983.742
2013	1	23	8	1,054.663
2013	1	23	9	1,050.387
2013	1	23	10	1,063.978
2013	1	23	11	1,072.260
2013	1	23	12	1,065.627
2013	1	23	13	1,065.326
2013	1	23	14	1,065.503
2013	1	23	15	1,053.991
2013	1	23	16	1,052.916
2013	1	23	17	1,069.236
2013	1	23	18	1,133.309
2013	1	23	19	1,158.185
2013	1	23	20	1,129.118
2013	1	23	21	1,096.778
2013	1	23	22	1,032.068

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	23	23	954.696
2013	1	23	24	887.742
2013	1	24	1	835.805
2013	1	24	2	812.173
2013	1	24	3	798.179
2013	1	24	4	800.065
2013	1	24	5	814.433
2013	1	24	6	874.228
2013	1	24	7	974.436
2013	1	24	8	1,037.530
2013	1	24	9	1,045.653
2013	1	24	10	1,051.345
2013	1	24	11	1,070.412
2013	1	24	12	1,065.792
2013	1	24	13	1,058.155
2013	1	24	14	1,061.016
2013	1	24	15	1,043.964
2013	1	24	16	1,039.155
2013	1	24	17	1,052.469
2013	1	24	18	1,127.489
2013	1	24	19	1,151.810
2013	1	24	20	1,131.852
2013	1	24	21	1,097.950
2013	1	24	22	1,033.643
2013	1	24	23	957.716
2013	1	24	24	885.746
2013	1	25	1	844.701
2013	1	25	2	818.661
2013	1	25	3	803.676
2013	1	25	4	804.358
2013	1	25	5	816.960
2013	1	25	6	867.184
2013	1	25	7	960.882
2013	1	25	8	1,027.853
2013	1	25	9	1,033.875
2013	1	25	10	1,048.366
2013	1	25	11	1,055.755
2013	1	25	12	1,058.029
2013	1	25	13	1,047.679
2013	1	25	14	1,039.343
2013	1	25	15	1,028.834
2013	1	25	16	1,025.836
2013	1	25	17	1,032.794
2013	1	25	18	1,077.207
2013	1	25	19	1,083.061
2013	1	25	20	1,055.373
2013	1	25	21	1,029.132
2013	1	25	22	982.600
2013	1	25	23	918.760
2013	1	25	24	859.152

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	26	1	809.775
2013	1	26	2	791.432
2013	1	26	3	777.828
2013	1	26	4	774.916
2013	1	26	5	774.883
2013	1	26	6	793.430
2013	1	26	7	834.942
2013	1	26	8	861.150
2013	1	26	9	894.630
2013	1	26	10	923.903
2013	1	26	11	927.827
2013	1	26	12	919.771
2013	1	26	13	914.723
2013	1	26	14	904.248
2013	1	26	15	896.543
2013	1	26	16	896.645
2013	1	26	17	912.944
2013	1	26	18	984.276
2013	1	26	19	1,014.547
2013	1	26	20	994.802
2013	1	26	21	973.417
2013	1	26	22	931.711
2013	1	26	23	877.656
2013	1	26	24	819.976
2013	1	27	1	780.602
2013	1	27	2	750.051
2013	1	27	3	740.685
2013	1	27	4	727.077
2013	1	27	5	731.880
2013	1	27	6	735.247
2013	1	27	7	766.651
2013	1	27	8	791.729
2013	1	27	9	823.892
2013	1	27	10	845.638
2013	1	27	11	857.238
2013	1	27	12	866.825
2013	1	27	13	865.588
2013	1	27	14	854.147
2013	1	27	15	855.493
2013	1	27	16	862.203
2013	1	27	17	891.239
2013	1	27	18	983.238
2013	1	27	19	1,016.183
2013	1	27	20	994.131
2013	1	27	21	967.466
2013	1	27	22	912.945
2013	1	27	23	856.313
2013	1	27	24	806.856
2013	1	28	1	767.476
2013	1	28	2	747.807

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	28	3	732.771
2013	1	28	4	734.280
2013	1	28	5	746.699
2013	1	28	6	807.289
2013	1	28	7	904.888
2013	1	28	8	974.128
2013	1	28	9	977.853
2013	1	28	10	994.101
2013	1	28	11	1,010.518
2013	1	28	12	1,018.419
2013	1	28	13	1,010.295
2013	1	28	14	998.855
2013	1	28	15	987.819
2013	1	28	16	982.196
2013	1	28	17	1,002.795
2013	1	28	18	1,056.680
2013	1	28	19	1,051.290
2013	1	28	20	1,025.745
2013	1	28	21	989.062
2013	1	28	22	928.755
2013	1	28	23	850.861
2013	1	28	24	782.151
2013	1	29	1	745.786
2013	1	29	2	719.794
2013	1	29	3	711.607
2013	1	29	4	707.021
2013	1	29	5	726.707
2013	1	29	6	783.968
2013	1	29	7	877.284
2013	1	29	8	937.491
2013	1	29	9	948.414
2013	1	29	10	959.011
2013	1	29	11	970.211
2013	1	29	12	971.557
2013	1	29	13	972.660
2013	1	29	14	971.292
2013	1	29	15	955.885
2013	1	29	16	959.781
2013	1	29	17	988.079
2013	1	29	18	1,024.926
2013	1	29	19	1,024.039
2013	1	29	20	1,000.704
2013	1	29	21	961.012
2013	1	29	22	898.709
2013	1	29	23	818.477
2013	1	29	24	764.083
2013	1	30	1	719.507
2013	1	30	2	687.656
2013	1	30	3	674.757
2013	1	30	4	667.758

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	1	30	5	685.922
2013	1	30	6	739.647
2013	1	30	7	841.450
2013	1	30	8	896.275
2013	1	30	9	903.843
2013	1	30	10	904.614
2013	1	30	11	929.581
2013	1	30	12	929.292
2013	1	30	13	930.623
2013	1	30	14	922.987
2013	1	30	15	914.427
2013	1	30	16	922.598
2013	1	30	17	937.162
2013	1	30	18	991.302
2013	1	30	19	995.652
2013	1	30	20	972.250
2013	1	30	21	931.902
2013	1	30	22	875.551
2013	1	30	23	798.498
2013	1	30	24	737.290
2013	1	31	1	699.668
2013	1	31	2	675.793
2013	1	31	3	665.984
2013	1	31	4	670.752
2013	1	31	5	691.980
2013	1	31	6	744.989
2013	1	31	7	865.490
2013	1	31	8	944.965
2013	1	31	9	961.741
2013	1	31	10	979.708
2013	1	31	11	983.165
2013	1	31	12	987.336
2013	1	31	13	993.063
2013	1	31	14	990.855
2013	1	31	15	994.743
2013	1	31	16	988.638
2013	1	31	17	1,014.826
2013	1	31	18	1,072.762
2013	1	31	19	1,094.109
2013	1	31	20	1,073.039
2013	1	31	21	1,040.400
2013	1	31	22	982.527
2013	1	31	23	903.469
2013	1	31	24	845.348
2013	2	1	1	804.564
2013	2	1	2	784.858
2013	2	1	3	771.485
2013	2	1	4	768.469
2013	2	1	5	786.829
2013	2	1	6	842.585

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	1	7	935.149
2013	2	1	8	994.163
2013	2	1	9	996.374
2013	2	1	10	1,002.763
2013	2	1	11	1,018.136
2013	2	1	12	1,016.464
2013	2	1	13	1,001.247
2013	2	1	14	994.016
2013	2	1	15	989.396
2013	2	1	16	974.872
2013	2	1	17	983.616
2013	2	1	18	1,037.752
2013	2	1	19	1,058.129
2013	2	1	20	1,036.035
2013	2	1	21	1,008.708
2013	2	1	22	966.178
2013	2	1	23	898.066
2013	2	1	24	837.799
2013	2	2	1	787.464
2013	2	2	2	768.032
2013	2	2	3	752.333
2013	2	2	4	747.311
2013	2	2	5	753.804
2013	2	2	6	773.467
2013	2	2	7	815.310
2013	2	2	8	847.505
2013	2	2	9	885.991
2013	2	2	10	915.810
2013	2	2	11	932.668
2013	2	2	12	943.888
2013	2	2	13	931.441
2013	2	2	14	926.518
2013	2	2	15	918.911
2013	2	2	16	917.064
2013	2	2	17	936.594
2013	2	2	18	986.751
2013	2	2	19	1,015.263
2013	2	2	20	1,001.870
2013	2	2	21	971.436
2013	2	2	22	931.667
2013	2	2	23	874.906
2013	2	2	24	825.143
2013	2	3	1	782.175
2013	2	3	2	759.131
2013	2	3	3	738.263
2013	2	3	4	731.496
2013	2	3	5	732.218
2013	2	3	6	749.686
2013	2	3	7	779.275
2013	2	3	8	801.677

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	3	9	833.717
2013	2	3	10	858.773
2013	2	3	11	859.804
2013	2	3	12	875.227
2013	2	3	13	878.528
2013	2	3	14	881.926
2013	2	3	15	879.926
2013	2	3	16	886.431
2013	2	3	17	908.231
2013	2	3	18	976.494
2013	2	3	19	983.541
2013	2	3	20	945.901
2013	2	3	21	931.062
2013	2	3	22	905.093
2013	2	3	23	867.216
2013	2	3	24	819.959
2013	2	4	1	778.392
2013	2	4	2	753.814
2013	2	4	3	744.410
2013	2	4	4	751.081
2013	2	4	5	768.536
2013	2	4	6	824.104
2013	2	4	7	926.758
2013	2	4	8	985.440
2013	2	4	9	996.884
2013	2	4	10	1,003.973
2013	2	4	11	1,014.289
2013	2	4	12	1,022.328
2013	2	4	13	1,014.366
2013	2	4	14	1,010.022
2013	2	4	15	1,005.455
2013	2	4	16	1,006.673
2013	2	4	17	1,024.040
2013	2	4	18	1,070.264
2013	2	4	19	1,103.916
2013	2	4	20	1,080.394
2013	2	4	21	1,048.686
2013	2	4	22	981.414
2013	2	4	23	906.943
2013	2	4	24	842.285
2013	2	5	1	797.131
2013	2	5	2	775.459
2013	2	5	3	765.165
2013	2	5	4	762.368
2013	2	5	5	773.775
2013	2	5	6	828.582
2013	2	5	7	935.397
2013	2	5	8	980.427
2013	2	5	9	990.483
2013	2	5	10	988.599

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	5	11	991.074
2013	2	5	12	988.269
2013	2	5	13	974.952
2013	2	5	14	979.901
2013	2	5	15	970.044
2013	2	5	16	975.069
2013	2	5	17	992.529
2013	2	5	18	1,038.624
2013	2	5	19	1,075.730
2013	2	5	20	1,053.678
2013	2	5	21	1,021.923
2013	2	5	22	964.636
2013	2	5	23	886.152
2013	2	5	24	827.249
2013	2	6	1	785.751
2013	2	6	2	762.667
2013	2	6	3	753.680
2013	2	6	4	744.574
2013	2	6	5	766.268
2013	2	6	6	819.022
2013	2	6	7	923.870
2013	2	6	8	978.000
2013	2	6	9	981.318
2013	2	6	10	990.509
2013	2	6	11	1,006.834
2013	2	6	12	1,002.161
2013	2	6	13	987.968
2013	2	6	14	986.501
2013	2	6	15	971.609
2013	2	6	16	971.271
2013	2	6	17	982.220
2013	2	6	18	1,036.519
2013	2	6	19	1,087.558
2013	2	6	20	1,071.244
2013	2	6	21	1,043.484
2013	2	6	22	985.986
2013	2	6	23	911.425
2013	2	6	24	851.335
2013	2	7	1	812.213
2013	2	7	2	786.224
2013	2	7	3	773.128
2013	2	7	4	771.330
2013	2	7	5	783.651
2013	2	7	6	836.513
2013	2	7	7	947.575
2013	2	7	8	998.580
2013	2	7	9	1,003.443
2013	2	7	10	1,009.431
2013	2	7	11	1,008.416
2013	2	7	12	999.692

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	7	13	990.826
2013	2	7	14	981.817
2013	2	7	15	972.679
2013	2	7	16	973.996
2013	2	7	17	985.893
2013	2	7	18	1,036.442
2013	2	7	19	1,062.286
2013	2	7	20	1,046.340
2013	2	7	21	1,005.916
2013	2	7	22	961.546
2013	2	7	23	881.043
2013	2	7	24	817.793
2013	2	8	1	770.381
2013	2	8	2	748.556
2013	2	8	3	735.897
2013	2	8	4	732.863
2013	2	8	5	739.874
2013	2	8	6	788.030
2013	2	8	7	889.429
2013	2	8	8	952.335
2013	2	8	9	960.012
2013	2	8	10	970.154
2013	2	8	11	977.588
2013	2	8	12	979.348
2013	2	8	13	983.483
2013	2	8	14	975.410
2013	2	8	15	964.446
2013	2	8	16	953.007
2013	2	8	17	951.041
2013	2	8	18	1,001.035
2013	2	8	19	1,025.686
2013	2	8	20	1,005.488
2013	2	8	21	979.040
2013	2	8	22	930.896
2013	2	8	23	861.762
2013	2	8	24	803.416
2013	2	9	1	759.757
2013	2	9	2	738.039
2013	2	9	3	722.789
2013	2	9	4	718.799
2013	2	9	5	723.221
2013	2	9	6	743.114
2013	2	9	7	783.311
2013	2	9	8	820.505
2013	2	9	9	852.004
2013	2	9	10	884.655
2013	2	9	11	906.089
2013	2	9	12	910.366
2013	2	9	13	907.821
2013	2	9	14	900.898

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	9	15	889.141
2013	2	9	16	886.036
2013	2	9	17	901.577
2013	2	9	18	948.039
2013	2	9	19	1,001.393
2013	2	9	20	980.580
2013	2	9	21	961.553
2013	2	9	22	922.279
2013	2	9	23	872.688
2013	2	9	24	823.116
2013	2	10	1	779.960
2013	2	10	2	759.689
2013	2	10	3	741.601
2013	2	10	4	738.493
2013	2	10	5	737.467
2013	2	10	6	753.306
2013	2	10	7	779.375
2013	2	10	8	797.322
2013	2	10	9	826.179
2013	2	10	10	838.067
2013	2	10	11	849.670
2013	2	10	12	844.319
2013	2	10	13	851.694
2013	2	10	14	844.572
2013	2	10	15	832.431
2013	2	10	16	826.910
2013	2	10	17	844.182
2013	2	10	18	919.738
2013	2	10	19	983.466
2013	2	10	20	965.289
2013	2	10	21	932.684
2013	2	10	22	885.612
2013	2	10	23	819.821
2013	2	10	24	768.925
2013	2	11	1	729.422
2013	2	11	2	708.992
2013	2	11	3	698.505
2013	2	11	4	695.350
2013	2	11	5	718.118
2013	2	11	6	780.329
2013	2	11	7	882.211
2013	2	11	8	938.385
2013	2	11	9	948.566
2013	2	11	10	949.880
2013	2	11	11	953.037
2013	2	11	12	939.915
2013	2	11	13	926.562
2013	2	11	14	924.248
2013	2	11	15	931.089
2013	2	11	16	940.935

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	11	17	962.915
2013	2	11	18	1,010.822
2013	2	11	19	1,056.032
2013	2	11	20	1,035.168
2013	2	11	21	1,004.274
2013	2	11	22	946.035
2013	2	11	23	868.600
2013	2	11	24	806.212
2013	2	12	1	764.617
2013	2	12	2	740.777
2013	2	12	3	730.051
2013	2	12	4	723.482
2013	2	12	5	749.849
2013	2	12	6	803.582
2013	2	12	7	904.762
2013	2	12	8	960.688
2013	2	12	9	974.259
2013	2	12	10	982.474
2013	2	12	11	993.277
2013	2	12	12	991.153
2013	2	12	13	987.199
2013	2	12	14	989.422
2013	2	12	15	980.865
2013	2	12	16	983.122
2013	2	12	17	995.408
2013	2	12	18	1,036.290
2013	2	12	19	1,067.181
2013	2	12	20	1,046.897
2013	2	12	21	1,009.744
2013	2	12	22	954.468
2013	2	12	23	874.727
2013	2	12	24	811.822
2013	2	13	1	765.606
2013	2	13	2	737.690
2013	2	13	3	724.680
2013	2	13	4	723.334
2013	2	13	5	736.244
2013	2	13	6	804.006
2013	2	13	7	894.635
2013	2	13	8	944.219
2013	2	13	9	955.863
2013	2	13	10	961.370
2013	2	13	11	968.032
2013	2	13	12	955.755
2013	2	13	13	945.404
2013	2	13	14	939.134
2013	2	13	15	920.726
2013	2	13	16	917.787
2013	2	13	17	923.572
2013	2	13	18	971.439

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	13	19	1,027.617
2013	2	13	20	1,014.603
2013	2	13	21	993.935
2013	2	13	22	935.951
2013	2	13	23	871.343
2013	2	13	24	808.960
2013	2	14	1	760.538
2013	2	14	2	738.992
2013	2	14	3	719.783
2013	2	14	4	720.302
2013	2	14	5	743.029
2013	2	14	6	796.553
2013	2	14	7	901.725
2013	2	14	8	941.343
2013	2	14	9	957.559
2013	2	14	10	966.259
2013	2	14	11	973.861
2013	2	14	12	952.568
2013	2	14	13	934.537
2013	2	14	14	926.469
2013	2	14	15	917.447
2013	2	14	16	913.969
2013	2	14	17	916.360
2013	2	14	18	973.184
2013	2	14	19	1,017.456
2013	2	14	20	995.628
2013	2	14	21	965.881
2013	2	14	22	915.403
2013	2	14	23	847.038
2013	2	14	24	781.405
2013	2	15	1	736.220
2013	2	15	2	714.463
2013	2	15	3	705.352
2013	2	15	4	702.061
2013	2	15	5	717.402
2013	2	15	6	776.328
2013	2	15	7	875.552
2013	2	15	8	920.200
2013	2	15	9	935.652
2013	2	15	10	948.239
2013	2	15	11	949.282
2013	2	15	12	946.888
2013	2	15	13	937.767
2013	2	15	14	928.076
2013	2	15	15	918.873
2013	2	15	16	917.421
2013	2	15	17	924.485
2013	2	15	18	953.242
2013	2	15	19	996.158
2013	2	15	20	981.541

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	15	21	956.588
2013	2	15	22	915.093
2013	2	15	23	846.596
2013	2	15	24	789.527
2013	2	16	1	746.561
2013	2	16	2	720.838
2013	2	16	3	709.390
2013	2	16	4	700.654
2013	2	16	5	711.019
2013	2	16	6	727.632
2013	2	16	7	766.852
2013	2	16	8	800.933
2013	2	16	9	836.244
2013	2	16	10	871.620
2013	2	16	11	878.402
2013	2	16	12	876.026
2013	2	16	13	864.888
2013	2	16	14	859.846
2013	2	16	15	842.655
2013	2	16	16	843.529
2013	2	16	17	863.884
2013	2	16	18	901.964
2013	2	16	19	962.691
2013	2	16	20	942.928
2013	2	16	21	925.994
2013	2	16	22	887.332
2013	2	16	23	833.938
2013	2	16	24	788.590
2013	2	17	1	749.697
2013	2	17	2	724.688
2013	2	17	3	711.347
2013	2	17	4	702.320
2013	2	17	5	707.558
2013	2	17	6	713.386
2013	2	17	7	734.964
2013	2	17	8	739.878
2013	2	17	9	784.589
2013	2	17	10	816.573
2013	2	17	11	834.893
2013	2	17	12	847.357
2013	2	17	13	853.910
2013	2	17	14	857.458
2013	2	17	15	860.850
2013	2	17	16	865.035
2013	2	17	17	886.422
2013	2	17	18	960.849
2013	2	17	19	1,016.079
2013	2	17	20	1,003.144
2013	2	17	21	973.594
2013	2	17	22	933.137

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	17	23	876.884
2013	2	17	24	818.152
2013	2	18	1	789.926
2013	2	18	2	766.713
2013	2	18	3	759.932
2013	2	18	4	756.270
2013	2	18	5	773.021
2013	2	18	6	817.887
2013	2	18	7	898.255
2013	2	18	8	939.987
2013	2	18	9	978.368
2013	2	18	10	985.255
2013	2	18	11	993.146
2013	2	18	12	990.133
2013	2	18	13	978.105
2013	2	18	14	970.524
2013	2	18	15	954.397
2013	2	18	16	951.397
2013	2	18	17	952.354
2013	2	18	18	997.044
2013	2	18	19	1,058.397
2013	2	18	20	1,035.364
2013	2	18	21	1,006.771
2013	2	18	22	950.336
2013	2	18	23	877.647
2013	2	18	24	821.269
2013	2	19	1	777.642
2013	2	19	2	743.905
2013	2	19	3	732.079
2013	2	19	4	727.929
2013	2	19	5	739.441
2013	2	19	6	795.623
2013	2	19	7	867.555
2013	2	19	8	913.300
2013	2	19	9	949.592
2013	2	19	10	971.906
2013	2	19	11	980.852
2013	2	19	12	987.188
2013	2	19	13	978.725
2013	2	19	14	972.185
2013	2	19	15	968.506
2013	2	19	16	971.979
2013	2	19	17	985.977
2013	2	19	18	1,016.663
2013	2	19	19	1,052.323
2013	2	19	20	1,031.854
2013	2	19	21	999.951
2013	2	19	22	954.539
2013	2	19	23	883.579
2013	2	19	24	821.105

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	20	1	777.645
2013	2	20	2	757.585
2013	2	20	3	742.320
2013	2	20	4	744.157
2013	2	20	5	760.434
2013	2	20	6	819.142
2013	2	20	7	896.732
2013	2	20	8	948.993
2013	2	20	9	977.375
2013	2	20	10	998.977
2013	2	20	11	1,007.931
2013	2	20	12	1,020.135
2013	2	20	13	1,018.705
2013	2	20	14	1,018.278
2013	2	20	15	1,015.789
2013	2	20	16	1,009.055
2013	2	20	17	1,016.993
2013	2	20	18	1,049.599
2013	2	20	19	1,093.995
2013	2	20	20	1,084.174
2013	2	20	21	1,047.925
2013	2	20	22	996.566
2013	2	20	23	917.445
2013	2	20	24	856.059
2013	2	21	1	812.265
2013	2	21	2	781.791
2013	2	21	3	775.211
2013	2	21	4	767.454
2013	2	21	5	790.001
2013	2	21	6	839.943
2013	2	21	7	924.710
2013	2	21	8	963.038
2013	2	21	9	1,003.720
2013	2	21	10	1,025.404
2013	2	21	11	1,045.182
2013	2	21	12	1,045.180
2013	2	21	13	1,038.800
2013	2	21	14	1,039.996
2013	2	21	15	1,021.948
2013	2	21	16	1,012.637
2013	2	21	17	1,018.464
2013	2	21	18	1,045.706
2013	2	21	19	1,090.400
2013	2	21	20	1,071.378
2013	2	21	21	1,035.556
2013	2	21	22	983.482
2013	2	21	23	909.890
2013	2	21	24	841.614
2013	2	22	1	804.491
2013	2	22	2	777.245

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	22	3	761.462
2013	2	22	4	752.970
2013	2	22	5	768.721
2013	2	22	6	819.649
2013	2	22	7	896.247
2013	2	22	8	935.752
2013	2	22	9	978.037
2013	2	22	10	1,006.672
2013	2	22	11	1,010.012
2013	2	22	12	1,003.420
2013	2	22	13	990.248
2013	2	22	14	985.680
2013	2	22	15	975.900
2013	2	22	16	970.313
2013	2	22	17	951.055
2013	2	22	18	979.088
2013	2	22	19	1,016.071
2013	2	22	20	995.416
2013	2	22	21	961.481
2013	2	22	22	919.331
2013	2	22	23	856.329
2013	2	22	24	791.081
2013	2	23	1	746.324
2013	2	23	2	725.306
2013	2	23	3	703.487
2013	2	23	4	696.567
2013	2	23	5	699.617
2013	2	23	6	718.486
2013	2	23	7	753.970
2013	2	23	8	785.469
2013	2	23	9	820.840
2013	2	23	10	859.205
2013	2	23	11	868.016
2013	2	23	12	874.434
2013	2	23	13	863.940
2013	2	23	14	854.371
2013	2	23	15	844.818
2013	2	23	16	840.484
2013	2	23	17	862.957
2013	2	23	18	901.433
2013	2	23	19	939.004
2013	2	23	20	919.084
2013	2	23	21	901.540
2013	2	23	22	866.933
2013	2	23	23	813.611
2013	2	23	24	763.336
2013	2	24	1	722.722
2013	2	24	2	695.951
2013	2	24	3	681.005
2013	2	24	4	672.451

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	24	5	676.673
2013	2	24	6	689.486
2013	2	24	7	716.709
2013	2	24	8	734.564
2013	2	24	9	771.506
2013	2	24	10	804.170
2013	2	24	11	826.055
2013	2	24	12	842.431
2013	2	24	13	848.829
2013	2	24	14	841.671
2013	2	24	15	838.545
2013	2	24	16	839.905
2013	2	24	17	870.943
2013	2	24	18	911.441
2013	2	24	19	966.055
2013	2	24	20	960.465
2013	2	24	21	927.873
2013	2	24	22	879.194
2013	2	24	23	827.991
2013	2	24	24	772.594
2013	2	25	1	734.953
2013	2	25	2	712.318
2013	2	25	3	703.110
2013	2	25	4	705.484
2013	2	25	5	722.362
2013	2	25	6	785.109
2013	2	25	7	883.728
2013	2	25	8	919.843
2013	2	25	9	942.506
2013	2	25	10	954.815
2013	2	25	11	964.854
2013	2	25	12	974.465
2013	2	25	13	967.127
2013	2	25	14	968.839
2013	2	25	15	958.781
2013	2	25	16	949.799
2013	2	25	17	960.176
2013	2	25	18	986.930
2013	2	25	19	1,046.565
2013	2	25	20	1,019.578
2013	2	25	21	995.971
2013	2	25	22	927.093
2013	2	25	23	855.943
2013	2	25	24	793.265
2013	2	26	1	752.117
2013	2	26	2	736.463
2013	2	26	3	723.224
2013	2	26	4	723.083
2013	2	26	5	749.154
2013	2	26	6	804.626

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	26	7	897.107
2013	2	26	8	929.811
2013	2	26	9	936.895
2013	2	26	10	937.340
2013	2	26	11	941.233
2013	2	26	12	934.727
2013	2	26	13	929.409
2013	2	26	14	920.676
2013	2	26	15	921.592
2013	2	26	16	927.713
2013	2	26	17	945.111
2013	2	26	18	986.502
2013	2	26	19	1,033.178
2013	2	26	20	1,010.947
2013	2	26	21	987.288
2013	2	26	22	926.063
2013	2	26	23	854.782
2013	2	26	24	789.644
2013	2	27	1	753.205
2013	2	27	2	732.571
2013	2	27	3	721.529
2013	2	27	4	721.286
2013	2	27	5	734.955
2013	2	27	6	792.958
2013	2	27	7	886.501
2013	2	27	8	924.064
2013	2	27	9	942.024
2013	2	27	10	964.355
2013	2	27	11	976.646
2013	2	27	12	975.082
2013	2	27	13	967.984
2013	2	27	14	966.555
2013	2	27	15	960.139
2013	2	27	16	954.020
2013	2	27	17	952.665
2013	2	27	18	981.933
2013	2	27	19	1,028.842
2013	2	27	20	1,019.138
2013	2	27	21	988.070
2013	2	27	22	925.835
2013	2	27	23	849.878
2013	2	27	24	791.814
2013	2	28	1	752.391
2013	2	28	2	732.174
2013	2	28	3	714.220
2013	2	28	4	710.049
2013	2	28	5	730.759
2013	2	28	6	789.576
2013	2	28	7	879.360
2013	2	28	8	912.767

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	2	28	9	929.214
2013	2	28	10	938.067
2013	2	28	11	945.015
2013	2	28	12	943.485
2013	2	28	13	943.465
2013	2	28	14	937.986
2013	2	28	15	930.758
2013	2	28	16	932.570
2013	2	28	17	952.150
2013	2	28	18	975.124
2013	2	28	19	1,021.055
2013	2	28	20	1,007.015
2013	2	28	21	980.311
2013	2	28	22	921.950
2013	2	28	23	847.076
2013	2	28	24	786.893
2013	3	1	1	752.748
2013	3	1	2	722.643
2013	3	1	3	712.523
2013	3	1	4	709.318
2013	3	1	5	725.769
2013	3	1	6	783.479
2013	3	1	7	877.566
2013	3	1	8	920.222
2013	3	1	9	943.525
2013	3	1	10	955.937
2013	3	1	11	964.657
2013	3	1	12	964.482
2013	3	1	13	956.188
2013	3	1	14	954.521
2013	3	1	15	946.924
2013	3	1	16	936.664
2013	3	1	17	937.406
2013	3	1	18	946.504
2013	3	1	19	992.309
2013	3	1	20	982.222
2013	3	1	21	954.465
2013	3	1	22	913.310
2013	3	1	23	844.906
2013	3	1	24	790.624
2013	3	2	1	742.108
2013	3	2	2	724.760
2013	3	2	3	708.672
2013	3	2	4	705.155
2013	3	2	5	708.252
2013	3	2	6	730.349
2013	3	2	7	769.473
2013	3	2	8	795.162
2013	3	2	9	840.490
2013	3	2	10	871.483

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	2	11	887.824
2013	3	2	12	888.787
2013	3	2	13	889.254
2013	3	2	14	882.999
2013	3	2	15	871.640
2013	3	2	16	872.803
2013	3	2	17	884.477
2013	3	2	18	912.110
2013	3	2	19	967.978
2013	3	2	20	960.717
2013	3	2	21	935.417
2013	3	2	22	897.259
2013	3	2	23	844.954
2013	3	2	24	789.455
2013	3	3	1	746.122
2013	3	3	2	723.486
2013	3	3	3	709.504
2013	3	3	4	701.516
2013	3	3	5	704.340
2013	3	3	6	714.889
2013	3	3	7	737.199
2013	3	3	8	753.118
2013	3	3	9	792.923
2013	3	3	10	826.513
2013	3	3	11	847.742
2013	3	3	12	850.771
2013	3	3	13	864.611
2013	3	3	14	861.252
2013	3	3	15	864.514
2013	3	3	16	870.304
2013	3	3	17	888.711
2013	3	3	18	932.219
2013	3	3	19	993.402
2013	3	3	20	983.479
2013	3	3	21	958.813
2013	3	3	22	911.868
2013	3	3	23	850.134
2013	3	3	24	794.008
2013	3	4	1	755.127
2013	3	4	2	732.502
2013	3	4	3	727.270
2013	3	4	4	729.120
2013	3	4	5	750.770
2013	3	4	6	814.822
2013	3	4	7	905.058
2013	3	4	8	949.571
2013	3	4	9	959.159
2013	3	4	10	981.301
2013	3	4	11	994.051
2013	3	4	12	991.841

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	4	13	983.783
2013	3	4	14	976.244
2013	3	4	15	968.015
2013	3	4	16	960.813
2013	3	4	17	970.024
2013	3	4	18	1,004.309
2013	3	4	19	1,058.906
2013	3	4	20	1,045.961
2013	3	4	21	1,014.997
2013	3	4	22	955.864
2013	3	4	23	874.399
2013	3	4	24	813.598
2013	3	5	1	776.543
2013	3	5	2	757.848
2013	3	5	3	744.203
2013	3	5	4	741.974
2013	3	5	5	757.980
2013	3	5	6	814.279
2013	3	5	7	896.530
2013	3	5	8	942.996
2013	3	5	9	958.049
2013	3	5	10	966.290
2013	3	5	11	971.728
2013	3	5	12	971.012
2013	3	5	13	960.345
2013	3	5	14	956.099
2013	3	5	15	944.337
2013	3	5	16	931.396
2013	3	5	17	940.839
2013	3	5	18	960.534
2013	3	5	19	1,031.465
2013	3	5	20	1,031.990
2013	3	5	21	1,003.748
2013	3	5	22	946.722
2013	3	5	23	867.220
2013	3	5	24	807.559
2013	3	6	1	772.465
2013	3	6	2	752.492
2013	3	6	3	742.381
2013	3	6	4	742.317
2013	3	6	5	761.272
2013	3	6	6	822.255
2013	3	6	7	896.905
2013	3	6	8	931.907
2013	3	6	9	951.162
2013	3	6	10	964.049
2013	3	6	11	959.566
2013	3	6	12	944.695
2013	3	6	13	935.178
2013	3	6	14	941.289

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	6	15	934.464
2013	3	6	16	936.366
2013	3	6	17	944.451
2013	3	6	18	970.422
2013	3	6	19	1,018.311
2013	3	6	20	1,009.179
2013	3	6	21	980.645
2013	3	6	22	916.348
2013	3	6	23	843.349
2013	3	6	24	779.521
2013	3	7	1	743.232
2013	3	7	2	719.306
2013	3	7	3	709.206
2013	3	7	4	706.840
2013	3	7	5	726.476
2013	3	7	6	776.428
2013	3	7	7	864.972
2013	3	7	8	900.371
2013	3	7	9	928.528
2013	3	7	10	935.036
2013	3	7	11	943.824
2013	3	7	12	950.480
2013	3	7	13	940.293
2013	3	7	14	944.069
2013	3	7	15	937.997
2013	3	7	16	925.140
2013	3	7	17	928.563
2013	3	7	18	945.556
2013	3	7	19	1,010.026
2013	3	7	20	1,007.409
2013	3	7	21	975.375
2013	3	7	22	921.124
2013	3	7	23	844.282
2013	3	7	24	782.887
2013	3	8	1	749.055
2013	3	8	2	725.796
2013	3	8	3	713.745
2013	3	8	4	710.359
2013	3	8	5	727.125
2013	3	8	6	783.788
2013	3	8	7	862.514
2013	3	8	8	900.581
2013	3	8	9	921.011
2013	3	8	10	920.577
2013	3	8	11	925.378
2013	3	8	12	924.333
2013	3	8	13	907.540
2013	3	8	14	906.937
2013	3	8	15	890.313
2013	3	8	16	878.185

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	8	17	869.732
2013	3	8	18	873.632
2013	3	8	19	931.892
2013	3	8	20	937.988
2013	3	8	21	925.069
2013	3	8	22	880.537
2013	3	8	23	815.073
2013	3	8	24	770.748
2013	3	9	1	722.368
2013	3	9	2	698.680
2013	3	9	3	689.593
2013	3	9	4	683.449
2013	3	9	5	687.863
2013	3	9	6	711.501
2013	3	9	7	738.803
2013	3	9	8	768.409
2013	3	9	9	806.525
2013	3	9	10	833.008
2013	3	9	11	833.705
2013	3	9	12	826.000
2013	3	9	13	810.228
2013	3	9	14	795.301
2013	3	9	15	778.435
2013	3	9	16	772.542
2013	3	9	17	785.454
2013	3	9	18	806.360
2013	3	9	19	872.354
2013	3	9	20	886.926
2013	3	9	21	867.141
2013	3	9	22	837.148
2013	3	9	23	788.995
2013	3	9	24	732.209
2013	3	10	1	698.421
2013	3	10	3	671.064
2013	3	10	4	664.689
2013	3	10	5	653.719
2013	3	10	6	657.679
2013	3	10	7	680.107
2013	3	10	8	703.035
2013	3	10	9	723.325
2013	3	10	10	749.862
2013	3	10	11	762.915
2013	3	10	12	779.851
2013	3	10	13	792.962
2013	3	10	14	787.923
2013	3	10	15	772.092
2013	3	10	16	758.730
2013	3	10	17	763.507
2013	3	10	18	773.051
2013	3	10	19	798.338

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	10	20	852.802
2013	3	10	21	863.911
2013	3	10	22	821.420
2013	3	10	23	767.359
2013	3	10	24	703.403
2013	3	11	1	667.635
2013	3	11	2	644.086
2013	3	11	3	629.256
2013	3	11	4	628.569
2013	3	11	5	642.295
2013	3	11	6	696.210
2013	3	11	7	802.003
2013	3	11	8	877.189
2013	3	11	9	892.422
2013	3	11	10	898.524
2013	3	11	11	913.297
2013	3	11	12	917.853
2013	3	11	13	915.766
2013	3	11	14	911.833
2013	3	11	15	899.120
2013	3	11	16	899.187
2013	3	11	17	900.234
2013	3	11	18	909.088
2013	3	11	19	925.813
2013	3	11	20	957.738
2013	3	11	21	942.277
2013	3	11	22	885.527
2013	3	11	23	810.825
2013	3	11	24	748.200
2013	3	12	1	695.992
2013	3	12	2	670.645
2013	3	12	3	656.746
2013	3	12	4	648.749
2013	3	12	5	666.298
2013	3	12	6	723.619
2013	3	12	7	823.054
2013	3	12	8	899.737
2013	3	12	9	909.236
2013	3	12	10	921.157
2013	3	12	11	931.237
2013	3	12	12	938.412
2013	3	12	13	927.104
2013	3	12	14	930.604
2013	3	12	15	925.470
2013	3	12	16	923.206
2013	3	12	17	923.872
2013	3	12	18	931.307
2013	3	12	19	939.889
2013	3	12	20	975.599
2013	3	12	21	973.132

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	12	22	921.923
2013	3	12	23	841.510
2013	3	12	24	775.511
2013	3	13	1	737.332
2013	3	13	2	711.795
2013	3	13	3	703.025
2013	3	13	4	697.562
2013	3	13	5	713.316
2013	3	13	6	766.597
2013	3	13	7	866.862
2013	3	13	8	926.209
2013	3	13	9	921.557
2013	3	13	10	927.261
2013	3	13	11	934.211
2013	3	13	12	939.476
2013	3	13	13	937.102
2013	3	13	14	938.828
2013	3	13	15	931.229
2013	3	13	16	926.788
2013	3	13	17	933.624
2013	3	13	18	934.752
2013	3	13	19	941.699
2013	3	13	20	998.351
2013	3	13	21	996.350
2013	3	13	22	954.819
2013	3	13	23	875.426
2013	3	13	24	812.750
2013	3	14	1	774.158
2013	3	14	2	749.701
2013	3	14	3	748.539
2013	3	14	4	748.740
2013	3	14	5	770.887
2013	3	14	6	818.550
2013	3	14	7	926.384
2013	3	14	8	978.497
2013	3	14	9	987.400
2013	3	14	10	996.637
2013	3	14	11	996.431
2013	3	14	12	995.115
2013	3	14	13	979.939
2013	3	14	14	981.783
2013	3	14	15	957.128
2013	3	14	16	949.254
2013	3	14	17	940.682
2013	3	14	18	940.757
2013	3	14	19	940.430
2013	3	14	20	999.329
2013	3	14	21	1,010.336
2013	3	14	22	960.830
2013	3	14	23	881.912

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	14	24	817.534
2013	3	15	1	771.173
2013	3	15	2	749.718
2013	3	15	3	736.969
2013	3	15	4	730.508
2013	3	15	5	745.610
2013	3	15	6	802.013
2013	3	15	7	887.710
2013	3	15	8	945.924
2013	3	15	9	949.511
2013	3	15	10	965.212
2013	3	15	11	980.317
2013	3	15	12	979.963
2013	3	15	13	969.624
2013	3	15	14	965.797
2013	3	15	15	950.225
2013	3	15	16	930.610
2013	3	15	17	918.462
2013	3	15	18	911.042
2013	3	15	19	908.912
2013	3	15	20	940.258
2013	3	15	21	944.231
2013	3	15	22	911.079
2013	3	15	23	850.830
2013	3	15	24	784.667
2013	3	16	1	736.334
2013	3	16	2	711.803
2013	3	16	3	687.289
2013	3	16	4	682.885
2013	3	16	5	691.886
2013	3	16	6	708.656
2013	3	16	7	747.890
2013	3	16	8	792.343
2013	3	16	9	825.146
2013	3	16	10	847.478
2013	3	16	11	863.892
2013	3	16	12	866.807
2013	3	16	13	861.558
2013	3	16	14	858.946
2013	3	16	15	846.956
2013	3	16	16	850.408
2013	3	16	17	850.185
2013	3	16	18	848.160
2013	3	16	19	845.955
2013	3	16	20	892.637
2013	3	16	21	908.517
2013	3	16	22	884.499
2013	3	16	23	838.209
2013	3	16	24	785.450
2013	3	17	1	741.448

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	17	2	715.644
2013	3	17	3	701.975
2013	3	17	4	690.638
2013	3	17	5	690.669
2013	3	17	6	702.350
2013	3	17	7	727.281
2013	3	17	8	747.855
2013	3	17	9	782.032
2013	3	17	10	806.134
2013	3	17	11	829.836
2013	3	17	12	842.481
2013	3	17	13	838.275
2013	3	17	14	842.744
2013	3	17	15	832.827
2013	3	17	16	825.521
2013	3	17	17	825.031
2013	3	17	18	831.049
2013	3	17	19	839.017
2013	3	17	20	895.358
2013	3	17	21	926.040
2013	3	17	22	886.193
2013	3	17	23	833.676
2013	3	17	24	782.090
2013	3	18	1	744.615
2013	3	18	2	725.066
2013	3	18	3	725.869
2013	3	18	4	719.378
2013	3	18	5	746.545
2013	3	18	6	798.396
2013	3	18	7	901.342
2013	3	18	8	965.796
2013	3	18	9	972.655
2013	3	18	10	977.264
2013	3	18	11	980.703
2013	3	18	12	983.067
2013	3	18	13	980.666
2013	3	18	14	978.305
2013	3	18	15	975.487
2013	3	18	16	971.926
2013	3	18	17	979.877
2013	3	18	18	989.133
2013	3	18	19	994.427
2013	3	18	20	1,029.758
2013	3	18	21	1,016.988
2013	3	18	22	951.081
2013	3	18	23	873.905
2013	3	18	24	803.027
2013	3	19	1	758.990
2013	3	19	2	729.366
2013	3	19	3	719.663

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	19	4	713.037
2013	3	19	5	725.789
2013	3	19	6	775.724
2013	3	19	7	885.795
2013	3	19	8	933.898
2013	3	19	9	944.008
2013	3	19	10	951.803
2013	3	19	11	961.936
2013	3	19	12	967.855
2013	3	19	13	967.969
2013	3	19	14	964.722
2013	3	19	15	948.016
2013	3	19	16	946.616
2013	3	19	17	937.185
2013	3	19	18	944.371
2013	3	19	19	952.774
2013	3	19	20	993.018
2013	3	19	21	1,005.436
2013	3	19	22	950.242
2013	3	19	23	871.717
2013	3	19	24	808.275
2013	3	20	1	769.532
2013	3	20	2	745.812
2013	3	20	3	736.006
2013	3	20	4	731.629
2013	3	20	5	750.623
2013	3	20	6	810.025
2013	3	20	7	911.544
2013	3	20	8	959.344
2013	3	20	9	967.785
2013	3	20	10	975.215
2013	3	20	11	968.320
2013	3	20	12	972.359
2013	3	20	13	963.383
2013	3	20	14	962.493
2013	3	20	15	954.325
2013	3	20	16	944.165
2013	3	20	17	944.201
2013	3	20	18	941.937
2013	3	20	19	952.511
2013	3	20	20	983.721
2013	3	20	21	995.843
2013	3	20	22	945.268
2013	3	20	23	871.007
2013	3	20	24	815.530
2013	3	21	1	774.145
2013	3	21	2	751.327
2013	3	21	3	740.857
2013	3	21	4	738.989
2013	3	21	5	758.360

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	21	6	813.301
2013	3	21	7	921.965
2013	3	21	8	959.306
2013	3	21	9	968.367
2013	3	21	10	965.410
2013	3	21	11	976.130
2013	3	21	12	982.753
2013	3	21	13	965.031
2013	3	21	14	959.906
2013	3	21	15	946.481
2013	3	21	16	941.807
2013	3	21	17	955.356
2013	3	21	18	953.818
2013	3	21	19	953.137
2013	3	21	20	986.217
2013	3	21	21	1,002.681
2013	3	21	22	948.513
2013	3	21	23	869.346
2013	3	21	24	810.772
2013	3	22	1	767.584
2013	3	22	2	742.312
2013	3	22	3	730.020
2013	3	22	4	728.997
2013	3	22	5	742.571
2013	3	22	6	797.811
2013	3	22	7	894.524
2013	3	22	8	941.570
2013	3	22	9	957.624
2013	3	22	10	972.236
2013	3	22	11	975.144
2013	3	22	12	968.689
2013	3	22	13	962.834
2013	3	22	14	959.311
2013	3	22	15	945.522
2013	3	22	16	936.304
2013	3	22	17	925.359
2013	3	22	18	927.199
2013	3	22	19	916.894
2013	3	22	20	943.894
2013	3	22	21	951.548
2013	3	22	22	914.058
2013	3	22	23	850.511
2013	3	22	24	785.250
2013	3	23	1	746.557
2013	3	23	2	716.126
2013	3	23	3	705.089
2013	3	23	4	699.846
2013	3	23	5	700.916
2013	3	23	6	718.248
2013	3	23	7	762.111

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	23	8	790.211
2013	3	23	9	819.956
2013	3	23	10	847.799
2013	3	23	11	854.697
2013	3	23	12	854.037
2013	3	23	13	838.648
2013	3	23	14	834.566
2013	3	23	15	826.422
2013	3	23	16	822.501
2013	3	23	17	826.327
2013	3	23	18	827.856
2013	3	23	19	834.070
2013	3	23	20	872.707
2013	3	23	21	896.050
2013	3	23	22	869.688
2013	3	23	23	821.738
2013	3	23	24	760.200
2013	3	24	1	720.444
2013	3	24	2	689.962
2013	3	24	3	676.021
2013	3	24	4	668.024
2013	3	24	5	667.772
2013	3	24	6	685.410
2013	3	24	7	717.795
2013	3	24	8	725.035
2013	3	24	9	759.328
2013	3	24	10	781.448
2013	3	24	11	797.908
2013	3	24	12	808.964
2013	3	24	13	811.284
2013	3	24	14	802.146
2013	3	24	15	790.331
2013	3	24	16	786.065
2013	3	24	17	800.558
2013	3	24	18	816.899
2013	3	24	19	833.661
2013	3	24	20	876.311
2013	3	24	21	899.404
2013	3	24	22	858.028
2013	3	24	23	796.207
2013	3	24	24	746.636
2013	3	25	1	707.110
2013	3	25	2	687.350
2013	3	25	3	675.581
2013	3	25	4	680.064
2013	3	25	5	692.465
2013	3	25	6	761.067
2013	3	25	7	869.393
2013	3	25	8	914.091
2013	3	25	9	931.283

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	25	10	937.115
2013	3	25	11	936.348
2013	3	25	12	948.394
2013	3	25	13	936.612
2013	3	25	14	932.505
2013	3	25	15	917.915
2013	3	25	16	907.991
2013	3	25	17	902.471
2013	3	25	18	908.194
2013	3	25	19	910.746
2013	3	25	20	948.493
2013	3	25	21	958.513
2013	3	25	22	905.054
2013	3	25	23	831.463
2013	3	25	24	763.532
2013	3	26	1	729.672
2013	3	26	2	708.585
2013	3	26	3	696.783
2013	3	26	4	695.223
2013	3	26	5	710.644
2013	3	26	6	771.150
2013	3	26	7	877.331
2013	3	26	8	930.276
2013	3	26	9	944.751
2013	3	26	10	952.124
2013	3	26	11	950.523
2013	3	26	12	942.457
2013	3	26	13	930.157
2013	3	26	14	920.167
2013	3	26	15	912.998
2013	3	26	16	890.661
2013	3	26	17	880.563
2013	3	26	18	869.923
2013	3	26	19	873.969
2013	3	26	20	910.649
2013	3	26	21	941.626
2013	3	26	22	891.962
2013	3	26	23	816.700
2013	3	26	24	753.691
2013	3	27	1	721.217
2013	3	27	2	696.413
2013	3	27	3	686.320
2013	3	27	4	687.092
2013	3	27	5	702.558
2013	3	27	6	765.160
2013	3	27	7	864.141
2013	3	27	8	907.213
2013	3	27	9	913.538
2013	3	27	10	917.244
2013	3	27	11	931.587

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	27	12	922.952
2013	3	27	13	915.415
2013	3	27	14	915.044
2013	3	27	15	914.110
2013	3	27	16	904.806
2013	3	27	17	907.125
2013	3	27	18	918.987
2013	3	27	19	925.371
2013	3	27	20	961.477
2013	3	27	21	960.695
2013	3	27	22	913.284
2013	3	27	23	838.481
2013	3	27	24	773.629
2013	3	28	1	732.073
2013	3	28	2	708.846
2013	3	28	3	696.614
2013	3	28	4	692.618
2013	3	28	5	705.593
2013	3	28	6	769.664
2013	3	28	7	861.238
2013	3	28	8	910.127
2013	3	28	9	934.917
2013	3	28	10	939.356
2013	3	28	11	942.088
2013	3	28	12	933.377
2013	3	28	13	919.839
2013	3	28	14	921.983
2013	3	28	15	913.910
2013	3	28	16	902.635
2013	3	28	17	893.408
2013	3	28	18	893.539
2013	3	28	19	896.391
2013	3	28	20	920.893
2013	3	28	21	938.647
2013	3	28	22	886.808
2013	3	28	23	824.158
2013	3	28	24	755.581
2013	3	29	1	705.168
2013	3	29	2	676.744
2013	3	29	3	664.797
2013	3	29	4	653.180
2013	3	29	5	655.760
2013	3	29	6	700.003
2013	3	29	7	759.938
2013	3	29	8	801.578
2013	3	29	9	830.203
2013	3	29	10	856.260
2013	3	29	11	860.444
2013	3	29	12	860.036
2013	3	29	13	841.386

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	29	14	831.825
2013	3	29	15	820.077
2013	3	29	16	806.078
2013	3	29	17	789.195
2013	3	29	18	782.341
2013	3	29	19	775.315
2013	3	29	20	805.517
2013	3	29	21	837.967
2013	3	29	22	812.568
2013	3	29	23	759.276
2013	3	29	24	711.524
2013	3	30	1	669.930
2013	3	30	2	643.358
2013	3	30	3	633.266
2013	3	30	4	627.179
2013	3	30	5	630.602
2013	3	30	6	652.378
2013	3	30	7	684.503
2013	3	30	8	706.416
2013	3	30	9	744.935
2013	3	30	10	762.669
2013	3	30	11	773.486
2013	3	30	12	766.062
2013	3	30	13	757.517
2013	3	30	14	738.071
2013	3	30	15	726.795
2013	3	30	16	718.971
2013	3	30	17	718.478
2013	3	30	18	721.221
2013	3	30	19	731.868
2013	3	30	20	764.416
2013	3	30	21	811.632
2013	3	30	22	784.651
2013	3	30	23	745.130
2013	3	30	24	691.005
2013	3	31	1	653.620
2013	3	31	2	625.315
2013	3	31	3	612.020
2013	3	31	4	601.349
2013	3	31	5	603.850
2013	3	31	6	619.490
2013	3	31	7	646.308
2013	3	31	8	661.551
2013	3	31	9	694.549
2013	3	31	10	717.154
2013	3	31	11	721.985
2013	3	31	12	717.615
2013	3	31	13	713.777
2013	3	31	14	707.012
2013	3	31	15	704.807

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	3	31	16	691.245
2013	3	31	17	699.124
2013	3	31	18	706.222
2013	3	31	19	712.885
2013	3	31	20	748.966
2013	3	31	21	784.952
2013	3	31	22	756.577
2013	3	31	23	715.721
2013	3	31	24	677.388
2013	4	1	1	638.775
2013	4	1	2	618.928
2013	4	1	3	613.898
2013	4	1	4	614.742
2013	4	1	5	623.500
2013	4	1	6	681.725
2013	4	1	7	763.993
2013	4	1	8	825.971
2013	4	1	9	876.710
2013	4	1	10	900.554
2013	4	1	11	920.773
2013	4	1	12	929.995
2013	4	1	13	929.201
2013	4	1	14	928.474
2013	4	1	15	913.835
2013	4	1	16	898.134
2013	4	1	17	893.552
2013	4	1	18	902.064
2013	4	1	19	899.520
2013	4	1	20	928.827
2013	4	1	21	958.715
2013	4	1	22	915.885
2013	4	1	23	846.827
2013	4	1	24	787.518
2013	4	2	1	738.583
2013	4	2	2	726.119
2013	4	2	3	706.247
2013	4	2	4	707.795
2013	4	2	5	721.557
2013	4	2	6	774.092
2013	4	2	7	853.260
2013	4	2	8	899.565
2013	4	2	9	933.340
2013	4	2	10	954.273
2013	4	2	11	971.668
2013	4	2	12	966.678
2013	4	2	13	965.701
2013	4	2	14	965.025
2013	4	2	15	947.338
2013	4	2	16	942.416
2013	4	2	17	932.329

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	2	18	937.095
2013	4	2	19	925.255
2013	4	2	20	949.079
2013	4	2	21	980.966
2013	4	2	22	935.755
2013	4	2	23	861.555
2013	4	2	24	800.370
2013	4	3	1	756.250
2013	4	3	2	733.790
2013	4	3	3	726.145
2013	4	3	4	716.717
2013	4	3	5	730.262
2013	4	3	6	773.353
2013	4	3	7	856.183
2013	4	3	8	895.298
2013	4	3	9	930.641
2013	4	3	10	950.941
2013	4	3	11	965.115
2013	4	3	12	970.670
2013	4	3	13	963.456
2013	4	3	14	957.780
2013	4	3	15	944.064
2013	4	3	16	928.621
2013	4	3	17	914.338
2013	4	3	18	903.639
2013	4	3	19	897.629
2013	4	3	20	919.370
2013	4	3	21	960.336
2013	4	3	22	925.069
2013	4	3	23	859.425
2013	4	3	24	794.638
2013	4	4	1	752.246
2013	4	4	2	730.579
2013	4	4	3	719.015
2013	4	4	4	716.803
2013	4	4	5	734.404
2013	4	4	6	780.121
2013	4	4	7	855.828
2013	4	4	8	891.770
2013	4	4	9	919.202
2013	4	4	10	935.695
2013	4	4	11	936.921
2013	4	4	12	927.356
2013	4	4	13	913.220
2013	4	4	14	904.453
2013	4	4	15	890.184
2013	4	4	16	874.810
2013	4	4	17	857.799
2013	4	4	18	846.301
2013	4	4	19	837.504

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	4	20	854.173
2013	4	4	21	896.693
2013	4	4	22	868.790
2013	4	4	23	812.163
2013	4	4	24	757.041
2013	4	5	1	720.833
2013	4	5	2	691.774
2013	4	5	3	681.962
2013	4	5	4	680.337
2013	4	5	5	690.987
2013	4	5	6	741.904
2013	4	5	7	805.275
2013	4	5	8	842.011
2013	4	5	9	876.569
2013	4	5	10	895.438
2013	4	5	11	900.793
2013	4	5	12	907.462
2013	4	5	13	894.442
2013	4	5	14	896.210
2013	4	5	15	887.193
2013	4	5	16	870.871
2013	4	5	17	859.926
2013	4	5	18	847.050
2013	4	5	19	837.027
2013	4	5	20	853.651
2013	4	5	21	904.053
2013	4	5	22	871.634
2013	4	5	23	813.216
2013	4	5	24	759.581
2013	4	6	1	717.002
2013	4	6	2	692.923
2013	4	6	3	681.858
2013	4	6	4	674.719
2013	4	6	5	676.159
2013	4	6	6	700.665
2013	4	6	7	728.629
2013	4	6	8	746.588
2013	4	6	9	780.595
2013	4	6	10	801.838
2013	4	6	11	813.177
2013	4	6	12	815.915
2013	4	6	13	797.487
2013	4	6	14	789.853
2013	4	6	15	771.218
2013	4	6	16	766.895
2013	4	6	17	758.479
2013	4	6	18	769.869
2013	4	6	19	784.949
2013	4	6	20	806.830
2013	4	6	21	851.355

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	6	22	822.389
2013	4	6	23	772.326
2013	4	6	24	725.725
2013	4	7	1	679.569
2013	4	7	2	649.546
2013	4	7	3	632.840
2013	4	7	4	625.531
2013	4	7	5	622.118
2013	4	7	6	632.876
2013	4	7	7	655.163
2013	4	7	8	664.836
2013	4	7	9	703.144
2013	4	7	10	727.798
2013	4	7	11	751.373
2013	4	7	12	762.789
2013	4	7	13	765.038
2013	4	7	14	758.385
2013	4	7	15	752.456
2013	4	7	16	743.283
2013	4	7	17	750.117
2013	4	7	18	751.787
2013	4	7	19	756.565
2013	4	7	20	776.850
2013	4	7	21	822.647
2013	4	7	22	798.025
2013	4	7	23	740.000
2013	4	7	24	692.207
2013	4	8	1	658.367
2013	4	8	2	638.704
2013	4	8	3	628.572
2013	4	8	4	630.129
2013	4	8	5	650.177
2013	4	8	6	702.592
2013	4	8	7	796.389
2013	4	8	8	852.400
2013	4	8	9	875.316
2013	4	8	10	886.056
2013	4	8	11	893.208
2013	4	8	12	890.619
2013	4	8	13	882.253
2013	4	8	14	879.071
2013	4	8	15	867.575
2013	4	8	16	863.964
2013	4	8	17	865.369
2013	4	8	18	882.501
2013	4	8	19	899.307
2013	4	8	20	922.485
2013	4	8	21	928.129
2013	4	8	22	867.658
2013	4	8	23	793.296

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	8	24	731.002
2013	4	9	1	693.414
2013	4	9	2	667.248
2013	4	9	3	650.380
2013	4	9	4	646.573
2013	4	9	5	656.197
2013	4	9	6	713.045
2013	4	9	7	808.623
2013	4	9	8	868.766
2013	4	9	9	893.205
2013	4	9	10	906.820
2013	4	9	11	918.733
2013	4	9	12	914.814
2013	4	9	13	906.181
2013	4	9	14	907.298
2013	4	9	15	891.810
2013	4	9	16	873.838
2013	4	9	17	858.221
2013	4	9	18	870.186
2013	4	9	19	888.590
2013	4	9	20	913.867
2013	4	9	21	922.522
2013	4	9	22	870.367
2013	4	9	23	792.822
2013	4	9	24	726.932
2013	4	10	1	683.370
2013	4	10	2	661.422
2013	4	10	3	645.138
2013	4	10	4	642.397
2013	4	10	5	651.769
2013	4	10	6	714.627
2013	4	10	7	811.301
2013	4	10	8	855.809
2013	4	10	9	886.366
2013	4	10	10	898.754
2013	4	10	11	917.391
2013	4	10	12	932.088
2013	4	10	13	928.129
2013	4	10	14	919.026
2013	4	10	15	925.607
2013	4	10	16	927.815
2013	4	10	17	948.961
2013	4	10	18	939.365
2013	4	10	19	936.547
2013	4	10	20	948.777
2013	4	10	21	944.792
2013	4	10	22	890.318
2013	4	10	23	812.628
2013	4	10	24	752.038
2013	4	11	1	702.714

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	11	2	681.524
2013	4	11	3	667.158
2013	4	11	4	660.557
2013	4	11	5	679.156
2013	4	11	6	741.703
2013	4	11	7	837.951
2013	4	11	8	887.125
2013	4	11	9	928.092
2013	4	11	10	950.890
2013	4	11	11	968.615
2013	4	11	12	972.166
2013	4	11	13	964.569
2013	4	11	14	972.392
2013	4	11	15	960.729
2013	4	11	16	962.041
2013	4	11	17	965.502
2013	4	11	18	962.921
2013	4	11	19	956.557
2013	4	11	20	969.701
2013	4	11	21	977.722
2013	4	11	22	928.975
2013	4	11	23	846.242
2013	4	11	24	780.023
2013	4	12	1	732.708
2013	4	12	2	706.065
2013	4	12	3	692.772
2013	4	12	4	690.751
2013	4	12	5	699.711
2013	4	12	6	758.361
2013	4	12	7	854.241
2013	4	12	8	913.951
2013	4	12	9	937.691
2013	4	12	10	948.622
2013	4	12	11	958.791
2013	4	12	12	955.422
2013	4	12	13	944.088
2013	4	12	14	930.988
2013	4	12	15	913.152
2013	4	12	16	908.137
2013	4	12	17	885.336
2013	4	12	18	864.929
2013	4	12	19	847.151
2013	4	12	20	873.263
2013	4	12	21	896.737
2013	4	12	22	860.207
2013	4	12	23	801.104
2013	4	12	24	736.378
2013	4	13	1	691.023
2013	4	13	2	663.154
2013	4	13	3	644.019

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	13	4	635.714
2013	4	13	5	636.466
2013	4	13	6	658.605
2013	4	13	7	693.341
2013	4	13	8	724.879
2013	4	13	9	777.188
2013	4	13	10	804.888
2013	4	13	11	821.131
2013	4	13	12	829.904
2013	4	13	13	823.712
2013	4	13	14	816.635
2013	4	13	15	807.137
2013	4	13	16	801.432
2013	4	13	17	811.707
2013	4	13	18	820.750
2013	4	13	19	814.778
2013	4	13	20	831.232
2013	4	13	21	859.695
2013	4	13	22	835.746
2013	4	13	23	782.351
2013	4	13	24	729.746
2013	4	14	1	685.060
2013	4	14	2	656.135
2013	4	14	3	643.380
2013	4	14	4	631.464
2013	4	14	5	634.891
2013	4	14	6	642.673
2013	4	14	7	662.903
2013	4	14	8	675.056
2013	4	14	9	720.235
2013	4	14	10	744.422
2013	4	14	11	763.384
2013	4	14	12	782.318
2013	4	14	13	788.878
2013	4	14	14	791.995
2013	4	14	15	777.997
2013	4	14	16	769.526
2013	4	14	17	767.698
2013	4	14	18	780.599
2013	4	14	19	779.617
2013	4	14	20	797.280
2013	4	14	21	862.790
2013	4	14	22	832.494
2013	4	14	23	773.123
2013	4	14	24	723.907
2013	4	15	1	683.212
2013	4	15	2	666.283
2013	4	15	3	656.747
2013	4	15	4	654.278
2013	4	15	5	669.275

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	15	6	736.867
2013	4	15	7	818.715
2013	4	15	8	875.041
2013	4	15	9	889.303
2013	4	15	10	892.303
2013	4	15	11	899.616
2013	4	15	12	899.657
2013	4	15	13	894.627
2013	4	15	14	896.025
2013	4	15	15	888.864
2013	4	15	16	876.988
2013	4	15	17	860.861
2013	4	15	18	849.367
2013	4	15	19	839.340
2013	4	15	20	849.400
2013	4	15	21	897.724
2013	4	15	22	856.966
2013	4	15	23	780.975
2013	4	15	24	712.575
2013	4	16	1	667.988
2013	4	16	2	644.530
2013	4	16	3	628.375
2013	4	16	4	621.335
2013	4	16	5	637.405
2013	4	16	6	692.467
2013	4	16	7	769.955
2013	4	16	8	824.306
2013	4	16	9	855.996
2013	4	16	10	883.135
2013	4	16	11	901.661
2013	4	16	12	914.393
2013	4	16	13	908.492
2013	4	16	14	910.656
2013	4	16	15	904.883
2013	4	16	16	898.831
2013	4	16	17	908.325
2013	4	16	18	902.253
2013	4	16	19	896.786
2013	4	16	20	894.717
2013	4	16	21	914.604
2013	4	16	22	866.044
2013	4	16	23	787.663
2013	4	16	24	727.519
2013	4	17	1	682.869
2013	4	17	2	659.612
2013	4	17	3	645.563
2013	4	17	4	648.005
2013	4	17	5	659.645
2013	4	17	6	720.301
2013	4	17	7	802.161

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	17	8	853.590
2013	4	17	9	878.970
2013	4	17	10	888.824
2013	4	17	11	898.242
2013	4	17	12	895.582
2013	4	17	13	889.968
2013	4	17	14	884.969
2013	4	17	15	878.939
2013	4	17	16	866.409
2013	4	17	17	852.591
2013	4	17	18	844.484
2013	4	17	19	835.158
2013	4	17	20	844.613
2013	4	17	21	905.267
2013	4	17	22	864.919
2013	4	17	23	791.117
2013	4	17	24	723.039
2013	4	18	1	679.053
2013	4	18	2	658.400
2013	4	18	3	642.675
2013	4	18	4	641.574
2013	4	18	5	648.615
2013	4	18	6	708.417
2013	4	18	7	797.576
2013	4	18	8	840.979
2013	4	18	9	870.321
2013	4	18	10	890.363
2013	4	18	11	900.590
2013	4	18	12	924.625
2013	4	18	13	918.054
2013	4	18	14	922.702
2013	4	18	15	922.742
2013	4	18	16	917.132
2013	4	18	17	901.921
2013	4	18	18	882.773
2013	4	18	19	864.711
2013	4	18	20	859.241
2013	4	18	21	911.801
2013	4	18	22	877.036
2013	4	18	23	801.815
2013	4	18	24	733.446
2013	4	19	1	687.990
2013	4	19	2	655.496
2013	4	19	3	640.307
2013	4	19	4	635.966
2013	4	19	5	645.177
2013	4	19	6	696.106
2013	4	19	7	769.284
2013	4	19	8	836.064
2013	4	19	9	875.282

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	19	10	903.086
2013	4	19	11	917.495
2013	4	19	12	927.626
2013	4	19	13	926.151
2013	4	19	14	924.309
2013	4	19	15	910.958
2013	4	19	16	870.660
2013	4	19	17	846.175
2013	4	19	18	845.147
2013	4	19	19	837.190
2013	4	19	20	832.726
2013	4	19	21	858.698
2013	4	19	22	834.641
2013	4	19	23	773.169
2013	4	19	24	715.089
2013	4	20	1	669.109
2013	4	20	2	645.993
2013	4	20	3	630.220
2013	4	20	4	624.062
2013	4	20	5	630.132
2013	4	20	6	653.723
2013	4	20	7	676.962
2013	4	20	8	709.626
2013	4	20	9	765.654
2013	4	20	10	798.546
2013	4	20	11	830.688
2013	4	20	12	831.854
2013	4	20	13	828.845
2013	4	20	14	818.573
2013	4	20	15	809.445
2013	4	20	16	800.500
2013	4	20	17	805.622
2013	4	20	18	813.913
2013	4	20	19	811.595
2013	4	20	20	815.579
2013	4	20	21	861.891
2013	4	20	22	843.353
2013	4	20	23	795.683
2013	4	20	24	740.713
2013	4	21	1	692.725
2013	4	21	2	670.854
2013	4	21	3	657.664
2013	4	21	4	652.192
2013	4	21	5	650.187
2013	4	21	6	666.840
2013	4	21	7	673.009
2013	4	21	8	698.381
2013	4	21	9	737.091
2013	4	21	10	768.649
2013	4	21	11	790.218

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	21	12	785.669
2013	4	21	13	787.086
2013	4	21	14	778.709
2013	4	21	15	761.370
2013	4	21	16	759.765
2013	4	21	17	763.825
2013	4	21	18	777.650
2013	4	21	19	779.452
2013	4	21	20	788.942
2013	4	21	21	852.924
2013	4	21	22	832.132
2013	4	21	23	782.143
2013	4	21	24	727.000
2013	4	22	1	681.996
2013	4	22	2	667.674
2013	4	22	3	659.351
2013	4	22	4	660.669
2013	4	22	5	680.545
2013	4	22	6	738.157
2013	4	22	7	823.585
2013	4	22	8	871.263
2013	4	22	9	899.956
2013	4	22	10	903.806
2013	4	22	11	913.897
2013	4	22	12	909.554
2013	4	22	13	902.186
2013	4	22	14	900.729
2013	4	22	15	882.882
2013	4	22	16	875.415
2013	4	22	17	859.342
2013	4	22	18	853.290
2013	4	22	19	843.113
2013	4	22	20	845.197
2013	4	22	21	898.718
2013	4	22	22	865.624
2013	4	22	23	792.095
2013	4	22	24	725.300
2013	4	23	1	684.542
2013	4	23	2	662.573
2013	4	23	3	644.487
2013	4	23	4	650.123
2013	4	23	5	663.425
2013	4	23	6	722.272
2013	4	23	7	793.374
2013	4	23	8	846.988
2013	4	23	9	872.295
2013	4	23	10	880.048
2013	4	23	11	890.155
2013	4	23	12	890.654
2013	4	23	13	883.620

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	23	14	885.321
2013	4	23	15	878.298
2013	4	23	16	870.596
2013	4	23	17	862.339
2013	4	23	18	850.199
2013	4	23	19	836.722
2013	4	23	20	844.023
2013	4	23	21	891.396
2013	4	23	22	853.806
2013	4	23	23	781.207
2013	4	23	24	710.982
2013	4	24	1	670.137
2013	4	24	2	647.196
2013	4	24	3	627.209
2013	4	24	4	631.033
2013	4	24	5	638.745
2013	4	24	6	699.451
2013	4	24	7	780.954
2013	4	24	8	842.607
2013	4	24	9	871.411
2013	4	24	10	886.900
2013	4	24	11	895.906
2013	4	24	12	897.697
2013	4	24	13	907.457
2013	4	24	14	911.460
2013	4	24	15	908.570
2013	4	24	16	901.474
2013	4	24	17	892.975
2013	4	24	18	884.936
2013	4	24	19	890.107
2013	4	24	20	890.795
2013	4	24	21	905.465
2013	4	24	22	864.789
2013	4	24	23	789.508
2013	4	24	24	734.384
2013	4	25	1	689.334
2013	4	25	2	666.544
2013	4	25	3	655.476
2013	4	25	4	656.250
2013	4	25	5	667.158
2013	4	25	6	728.008
2013	4	25	7	802.136
2013	4	25	8	857.962
2013	4	25	9	879.313
2013	4	25	10	890.869
2013	4	25	11	900.391
2013	4	25	12	898.547
2013	4	25	13	888.158
2013	4	25	14	881.048
2013	4	25	15	876.612

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	25	16	863.727
2013	4	25	17	847.490
2013	4	25	18	841.998
2013	4	25	19	839.669
2013	4	25	20	865.957
2013	4	25	21	901.525
2013	4	25	22	861.921
2013	4	25	23	786.585
2013	4	25	24	723.662
2013	4	26	1	678.591
2013	4	26	2	655.945
2013	4	26	3	641.858
2013	4	26	4	640.266
2013	4	26	5	654.860
2013	4	26	6	711.383
2013	4	26	7	782.219
2013	4	26	8	837.923
2013	4	26	9	857.205
2013	4	26	10	873.055
2013	4	26	11	876.083
2013	4	26	12	882.334
2013	4	26	13	870.860
2013	4	26	14	866.611
2013	4	26	15	850.645
2013	4	26	16	835.880
2013	4	26	17	815.394
2013	4	26	18	804.047
2013	4	26	19	788.229
2013	4	26	20	788.717
2013	4	26	21	839.322
2013	4	26	22	825.337
2013	4	26	23	770.101
2013	4	26	24	706.675
2013	4	27	1	661.020
2013	4	27	2	640.134
2013	4	27	3	620.022
2013	4	27	4	616.909
2013	4	27	5	623.432
2013	4	27	6	643.270
2013	4	27	7	660.712
2013	4	27	8	699.128
2013	4	27	9	737.089
2013	4	27	10	754.072
2013	4	27	11	764.934
2013	4	27	12	767.543
2013	4	27	13	755.305
2013	4	27	14	747.987
2013	4	27	15	738.022
2013	4	27	16	737.442
2013	4	27	17	732.305

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	27	18	736.554
2013	4	27	19	731.678
2013	4	27	20	731.607
2013	4	27	21	775.714
2013	4	27	22	767.945
2013	4	27	23	722.354
2013	4	27	24	665.813
2013	4	28	1	623.294
2013	4	28	2	595.808
2013	4	28	3	582.053
2013	4	28	4	574.721
2013	4	28	5	577.867
2013	4	28	6	588.323
2013	4	28	7	586.852
2013	4	28	8	617.070
2013	4	28	9	660.021
2013	4	28	10	695.529
2013	4	28	11	712.652
2013	4	28	12	731.665
2013	4	28	13	737.818
2013	4	28	14	736.654
2013	4	28	15	730.967
2013	4	28	16	727.936
2013	4	28	17	731.694
2013	4	28	18	747.549
2013	4	28	19	750.907
2013	4	28	20	777.419
2013	4	28	21	798.310
2013	4	28	22	768.545
2013	4	28	23	711.288
2013	4	28	24	660.692
2013	4	29	1	628.419
2013	4	29	2	604.631
2013	4	29	3	594.604
2013	4	29	4	592.998
2013	4	29	5	609.888
2013	4	29	6	666.261
2013	4	29	7	750.063
2013	4	29	8	810.264
2013	4	29	9	850.361
2013	4	29	10	870.430
2013	4	29	11	893.678
2013	4	29	12	903.496
2013	4	29	13	901.583
2013	4	29	14	901.509
2013	4	29	15	901.467
2013	4	29	16	882.955
2013	4	29	17	872.904
2013	4	29	18	863.244
2013	4	29	19	855.151

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	4	29	20	851.624
2013	4	29	21	896.058
2013	4	29	22	858.640
2013	4	29	23	782.676
2013	4	29	24	717.317
2013	4	30	1	665.841
2013	4	30	2	646.309
2013	4	30	3	624.845
2013	4	30	4	621.837
2013	4	30	5	635.357
2013	4	30	6	688.652
2013	4	30	7	759.375
2013	4	30	8	819.508
2013	4	30	9	865.324
2013	4	30	10	884.242
2013	4	30	11	904.654
2013	4	30	12	916.078
2013	4	30	13	913.715
2013	4	30	14	920.402
2013	4	30	15	919.754
2013	4	30	16	912.825
2013	4	30	17	902.567
2013	4	30	18	885.387
2013	4	30	19	867.312
2013	4	30	20	861.353
2013	4	30	21	900.288
2013	4	30	22	872.896
2013	4	30	23	791.660
2013	4	30	24	719.560
2013	5	1	1	680.136
2013	5	1	2	654.325
2013	5	1	3	633.082
2013	5	1	4	626.099
2013	5	1	5	639.881
2013	5	1	6	684.082
2013	5	1	7	755.755
2013	5	1	8	822.990
2013	5	1	9	857.020
2013	5	1	10	884.409
2013	5	1	11	900.179
2013	5	1	12	917.870
2013	5	1	13	920.848
2013	5	1	14	933.729
2013	5	1	15	935.038
2013	5	1	16	930.856
2013	5	1	17	919.263
2013	5	1	18	904.186
2013	5	1	19	881.339
2013	5	1	20	861.678
2013	5	1	21	901.294

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	1	22	876.867
2013	5	1	23	799.945
2013	5	1	24	727.219
2013	5	2	1	676.815
2013	5	2	2	645.879
2013	5	2	3	629.866
2013	5	2	4	620.990
2013	5	2	5	630.607
2013	5	2	6	674.461
2013	5	2	7	701.938
2013	5	2	8	806.563
2013	5	2	9	849.077
2013	5	2	10	886.738
2013	5	2	11	915.725
2013	5	2	12	930.767
2013	5	2	13	936.484
2013	5	2	14	944.930
2013	5	2	15	945.773
2013	5	2	16	935.619
2013	5	2	17	916.880
2013	5	2	18	897.394
2013	5	2	19	891.446
2013	5	2	20	880.242
2013	5	2	21	912.496
2013	5	2	22	891.406
2013	5	2	23	805.580
2013	5	2	24	730.640
2013	5	3	1	676.880
2013	5	3	2	647.443
2013	5	3	3	633.909
2013	5	3	4	619.877
2013	5	3	5	632.002
2013	5	3	6	676.856
2013	5	3	7	742.419
2013	5	3	8	816.329
2013	5	3	9	871.531
2013	5	3	10	905.548
2013	5	3	11	934.878
2013	5	3	12	955.564
2013	5	3	13	953.568
2013	5	3	14	969.516
2013	5	3	15	964.587
2013	5	3	16	957.481
2013	5	3	17	935.163
2013	5	3	18	911.878
2013	5	3	19	880.784
2013	5	3	20	855.050
2013	5	3	21	873.599
2013	5	3	22	860.643
2013	5	3	23	791.668

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	3	24	713.798
2013	5	4	1	662.421
2013	5	4	2	626.438
2013	5	4	3	606.876
2013	5	4	4	596.545
2013	5	4	5	596.521
2013	5	4	6	609.069
2013	5	4	7	613.909
2013	5	4	8	660.095
2013	5	4	9	712.652
2013	5	4	10	748.603
2013	5	4	11	770.300
2013	5	4	12	776.139
2013	5	4	13	778.639
2013	5	4	14	775.530
2013	5	4	15	775.552
2013	5	4	16	769.499
2013	5	4	17	779.307
2013	5	4	18	784.014
2013	5	4	19	776.717
2013	5	4	20	762.516
2013	5	4	21	783.557
2013	5	4	22	783.231
2013	5	4	23	731.585
2013	5	4	24	668.384
2013	5	5	1	627.440
2013	5	5	2	594.007
2013	5	5	3	574.070
2013	5	5	4	566.078
2013	5	5	5	560.739
2013	5	5	6	567.887
2013	5	5	7	561.991
2013	5	5	8	596.100
2013	5	5	9	650.871
2013	5	5	10	696.742
2013	5	5	11	719.579
2013	5	5	12	749.459
2013	5	5	13	760.881
2013	5	5	14	769.764
2013	5	5	15	765.890
2013	5	5	16	773.667
2013	5	5	17	780.596
2013	5	5	18	790.575
2013	5	5	19	786.161
2013	5	5	20	774.788
2013	5	5	21	812.067
2013	5	5	22	805.242
2013	5	5	23	740.221
2013	5	5	24	680.169
2013	5	6	1	634.648

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	6	2	612.841
2013	5	6	3	598.889
2013	5	6	4	596.520
2013	5	6	5	607.324
2013	5	6	6	658.515
2013	5	6	7	720.613
2013	5	6	8	799.569
2013	5	6	9	850.465
2013	5	6	10	879.337
2013	5	6	11	915.382
2013	5	6	12	932.178
2013	5	6	13	940.181
2013	5	6	14	950.725
2013	5	6	15	947.678
2013	5	6	16	945.286
2013	5	6	17	931.943
2013	5	6	18	914.792
2013	5	6	19	895.400
2013	5	6	20	874.314
2013	5	6	21	902.979
2013	5	6	22	881.546
2013	5	6	23	797.707
2013	5	6	24	722.965
2013	5	7	1	676.792
2013	5	7	2	651.721
2013	5	7	3	635.656
2013	5	7	4	626.605
2013	5	7	5	640.412
2013	5	7	6	681.598
2013	5	7	7	745.856
2013	5	7	8	816.775
2013	5	7	9	871.789
2013	5	7	10	909.503
2013	5	7	11	945.353
2013	5	7	12	964.315
2013	5	7	13	977.032
2013	5	7	14	987.132
2013	5	7	15	982.318
2013	5	7	16	980.996
2013	5	7	17	972.893
2013	5	7	18	946.731
2013	5	7	19	919.530
2013	5	7	20	897.898
2013	5	7	21	919.236
2013	5	7	22	900.458
2013	5	7	23	813.304
2013	5	7	24	736.594
2013	5	8	1	688.212
2013	5	8	2	659.050
2013	5	8	3	637.243

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	8	4	630.911
2013	5	8	5	644.069
2013	5	8	6	685.062
2013	5	8	7	751.285
2013	5	8	8	830.494
2013	5	8	9	874.075
2013	5	8	10	902.271
2013	5	8	11	934.216
2013	5	8	12	949.756
2013	5	8	13	953.941
2013	5	8	14	958.710
2013	5	8	15	944.416
2013	5	8	16	934.493
2013	5	8	17	929.650
2013	5	8	18	911.172
2013	5	8	19	899.361
2013	5	8	20	889.294
2013	5	8	21	916.344
2013	5	8	22	882.749
2013	5	8	23	803.540
2013	5	8	24	738.783
2013	5	9	1	684.342
2013	5	9	2	657.351
2013	5	9	3	644.814
2013	5	9	4	634.258
2013	5	9	5	651.623
2013	5	9	6	695.939
2013	5	9	7	757.492
2013	5	9	8	827.757
2013	5	9	9	880.238
2013	5	9	10	899.577
2013	5	9	11	926.239
2013	5	9	12	944.038
2013	5	9	13	937.093
2013	5	9	14	958.168
2013	5	9	15	955.272
2013	5	9	16	943.491
2013	5	9	17	935.330
2013	5	9	18	918.465
2013	5	9	19	890.524
2013	5	9	20	876.324
2013	5	9	21	907.004
2013	5	9	22	888.158
2013	5	9	23	812.804
2013	5	9	24	733.849
2013	5	10	1	688.439
2013	5	10	2	656.700
2013	5	10	3	640.541
2013	5	10	4	626.565
2013	5	10	5	639.422

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	10	6	679.055
2013	5	10	7	738.644
2013	5	10	8	809.881
2013	5	10	9	861.435
2013	5	10	10	898.032
2013	5	10	11	914.444
2013	5	10	12	920.040
2013	5	10	13	916.062
2013	5	10	14	924.853
2013	5	10	15	920.620
2013	5	10	16	915.962
2013	5	10	17	908.063
2013	5	10	18	889.640
2013	5	10	19	886.759
2013	5	10	20	868.626
2013	5	10	21	875.407
2013	5	10	22	844.428
2013	5	10	23	774.154
2013	5	10	24	711.210
2013	5	11	1	662.468
2013	5	11	2	631.744
2013	5	11	3	613.633
2013	5	11	4	603.298
2013	5	11	5	607.285
2013	5	11	6	619.164
2013	5	11	7	625.729
2013	5	11	8	662.493
2013	5	11	9	710.989
2013	5	11	10	751.873
2013	5	11	11	766.676
2013	5	11	12	772.578
2013	5	11	13	771.490
2013	5	11	14	755.535
2013	5	11	15	746.299
2013	5	11	16	741.774
2013	5	11	17	736.835
2013	5	11	18	739.920
2013	5	11	19	735.582
2013	5	11	20	732.512
2013	5	11	21	763.943
2013	5	11	22	779.692
2013	5	11	23	729.745
2013	5	11	24	672.140
2013	5	12	1	620.888
2013	5	12	2	596.115
2013	5	12	3	576.063
2013	5	12	4	572.981
2013	5	12	5	565.891
2013	5	12	6	573.360
2013	5	12	7	577.391

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	12	8	610.801
2013	5	12	9	657.870
2013	5	12	10	693.206
2013	5	12	11	710.005
2013	5	12	12	720.096
2013	5	12	13	719.185
2013	5	12	14	716.510
2013	5	12	15	711.245
2013	5	12	16	706.417
2013	5	12	17	720.615
2013	5	12	18	737.487
2013	5	12	19	735.304
2013	5	12	20	748.452
2013	5	12	21	798.383
2013	5	12	22	790.846
2013	5	12	23	740.406
2013	5	12	24	689.250
2013	5	13	1	646.368
2013	5	13	2	633.646
2013	5	13	3	616.299
2013	5	13	4	619.670
2013	5	13	5	636.438
2013	5	13	6	695.140
2013	5	13	7	761.218
2013	5	13	8	838.093
2013	5	13	9	877.115
2013	5	13	10	898.630
2013	5	13	11	917.760
2013	5	13	12	918.574
2013	5	13	13	910.935
2013	5	13	14	910.382
2013	5	13	15	892.753
2013	5	13	16	878.644
2013	5	13	17	875.846
2013	5	13	18	857.628
2013	5	13	19	854.457
2013	5	13	20	847.996
2013	5	13	21	884.350
2013	5	13	22	879.214
2013	5	13	23	802.922
2013	5	13	24	733.732
2013	5	14	1	691.050
2013	5	14	2	667.013
2013	5	14	3	652.947
2013	5	14	4	651.655
2013	5	14	5	669.978
2013	5	14	6	715.933
2013	5	14	7	785.692
2013	5	14	8	844.631
2013	5	14	9	872.177

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	14	10	884.009
2013	5	14	11	893.963
2013	5	14	12	900.697
2013	5	14	13	889.764
2013	5	14	14	891.309
2013	5	14	15	887.262
2013	5	14	16	880.838
2013	5	14	17	861.664
2013	5	14	18	850.646
2013	5	14	19	845.580
2013	5	14	20	834.088
2013	5	14	21	872.126
2013	5	14	22	863.388
2013	5	14	23	785.767
2013	5	14	24	717.119
2013	5	15	1	672.904
2013	5	15	2	647.043
2013	5	15	3	630.721
2013	5	15	4	629.681
2013	5	15	5	641.076
2013	5	15	6	689.357
2013	5	15	7	766.898
2013	5	15	8	826.795
2013	5	15	9	877.167
2013	5	15	10	891.582
2013	5	15	11	907.767
2013	5	15	12	925.801
2013	5	15	13	930.329
2013	5	15	14	952.955
2013	5	15	15	960.473
2013	5	15	16	951.943
2013	5	15	17	935.722
2013	5	15	18	913.956
2013	5	15	19	883.022
2013	5	15	20	869.593
2013	5	15	21	884.982
2013	5	15	22	875.389
2013	5	15	23	809.711
2013	5	15	24	728.794
2013	5	16	1	690.077
2013	5	16	2	654.478
2013	5	16	3	636.250
2013	5	16	4	630.338
2013	5	16	5	637.163
2013	5	16	6	674.355
2013	5	16	7	738.250
2013	5	16	8	821.052
2013	5	16	9	875.374
2013	5	16	10	910.860
2013	5	16	11	932.218

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	16	12	949.960
2013	5	16	13	951.617
2013	5	16	14	960.286
2013	5	16	15	959.740
2013	5	16	16	947.102
2013	5	16	17	931.691
2013	5	16	18	903.561
2013	5	16	19	874.345
2013	5	16	20	850.420
2013	5	16	21	865.225
2013	5	16	22	864.290
2013	5	16	23	787.997
2013	5	16	24	719.780
2013	5	17	1	666.976
2013	5	17	2	639.434
2013	5	17	3	619.968
2013	5	17	4	610.943
2013	5	17	5	623.748
2013	5	17	6	659.576
2013	5	17	7	721.413
2013	5	17	8	794.584
2013	5	17	9	835.646
2013	5	17	10	862.985
2013	5	17	11	885.225
2013	5	17	12	890.024
2013	5	17	13	894.055
2013	5	17	14	897.729
2013	5	17	15	890.512
2013	5	17	16	876.493
2013	5	17	17	859.849
2013	5	17	18	840.097
2013	5	17	19	814.217
2013	5	17	20	793.211
2013	5	17	21	812.749
2013	5	17	22	822.661
2013	5	17	23	756.173
2013	5	17	24	695.626
2013	5	18	1	640.101
2013	5	18	2	614.405
2013	5	18	3	592.448
2013	5	18	4	586.073
2013	5	18	5	592.264
2013	5	18	6	596.274
2013	5	18	7	615.652
2013	5	18	8	659.100
2013	5	18	9	708.085
2013	5	18	10	749.867
2013	5	18	11	764.031
2013	5	18	12	768.967
2013	5	18	13	771.210

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	18	14	762.396
2013	5	18	15	762.168
2013	5	18	16	759.026
2013	5	18	17	758.289
2013	5	18	18	764.647
2013	5	18	19	758.958
2013	5	18	20	747.328
2013	5	18	21	763.499
2013	5	18	22	783.347
2013	5	18	23	733.204
2013	5	18	24	681.085
2013	5	19	1	635.588
2013	5	19	2	600.619
2013	5	19	3	586.761
2013	5	19	4	574.866
2013	5	19	5	572.886
2013	5	19	6	577.791
2013	5	19	7	582.236
2013	5	19	8	609.231
2013	5	19	9	667.765
2013	5	19	10	708.032
2013	5	19	11	736.779
2013	5	19	12	765.502
2013	5	19	13	782.488
2013	5	19	14	799.226
2013	5	19	15	809.981
2013	5	19	16	822.027
2013	5	19	17	839.416
2013	5	19	18	850.154
2013	5	19	19	842.783
2013	5	19	20	834.405
2013	5	19	21	854.392
2013	5	19	22	864.507
2013	5	19	23	801.493
2013	5	19	24	734.579
2013	5	20	1	683.085
2013	5	20	2	657.009
2013	5	20	3	635.142
2013	5	20	4	633.218
2013	5	20	5	647.082
2013	5	20	6	697.129
2013	5	20	7	769.790
2013	5	20	8	863.784
2013	5	20	9	924.847
2013	5	20	10	982.637
2013	5	20	11	1,030.172
2013	5	20	12	1,065.758
2013	5	20	13	1,088.583
2013	5	20	14	1,096.293
2013	5	20	15	1,106.630

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	20	16	1,118.878
2013	5	20	17	1,111.884
2013	5	20	18	1,103.420
2013	5	20	19	1,086.549
2013	5	20	20	1,060.832
2013	5	20	21	1,067.469
2013	5	20	22	1,043.532
2013	5	20	23	948.757
2013	5	20	24	860.282
2013	5	21	1	797.899
2013	5	21	2	748.283
2013	5	21	3	713.263
2013	5	21	4	704.257
2013	5	21	5	712.069
2013	5	21	6	761.474
2013	5	21	7	833.565
2013	5	21	8	912.744
2013	5	21	9	973.499
2013	5	21	10	1,022.391
2013	5	21	11	1,096.172
2013	5	21	12	1,148.164
2013	5	21	13	1,171.212
2013	5	21	14	1,191.794
2013	5	21	15	1,198.116
2013	5	21	16	1,204.172
2013	5	21	17	1,188.859
2013	5	21	18	1,163.128
2013	5	21	19	1,126.750
2013	5	21	20	1,055.411
2013	5	21	21	1,043.951
2013	5	21	22	1,014.778
2013	5	21	23	920.202
2013	5	21	24	833.969
2013	5	22	1	762.961
2013	5	22	2	728.320
2013	5	22	3	702.224
2013	5	22	4	692.894
2013	5	22	5	706.758
2013	5	22	6	754.403
2013	5	22	7	825.946
2013	5	22	8	917.686
2013	5	22	9	974.817
2013	5	22	10	1,011.899
2013	5	22	11	1,049.448
2013	5	22	12	1,105.541
2013	5	22	13	1,143.547
2013	5	22	14	1,179.353
2013	5	22	15	1,191.027
2013	5	22	16	1,197.281
2013	5	22	17	1,208.531

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	22	18	1,194.628
2013	5	22	19	1,172.545
2013	5	22	20	1,142.740
2013	5	22	21	1,138.736
2013	5	22	22	1,086.707
2013	5	22	23	992.980
2013	5	22	24	899.870
2013	5	23	1	823.830
2013	5	23	2	781.937
2013	5	23	3	748.462
2013	5	23	4	740.998
2013	5	23	5	746.209
2013	5	23	6	794.870
2013	5	23	7	869.553
2013	5	23	8	940.153
2013	5	23	9	990.883
2013	5	23	10	1,040.620
2013	5	23	11	1,065.692
2013	5	23	12	1,067.078
2013	5	23	13	1,082.821
2013	5	23	14	1,089.666
2013	5	23	15	1,093.251
2013	5	23	16	1,060.205
2013	5	23	17	1,026.037
2013	5	23	18	1,009.906
2013	5	23	19	960.524
2013	5	23	20	928.345
2013	5	23	21	927.097
2013	5	23	22	878.235
2013	5	23	23	796.358
2013	5	23	24	720.042
2013	5	24	1	672.239
2013	5	24	2	640.682
2013	5	24	3	622.488
2013	5	24	4	615.309
2013	5	24	5	620.819
2013	5	24	6	666.017
2013	5	24	7	722.128
2013	5	24	8	792.622
2013	5	24	9	839.566
2013	5	24	10	862.865
2013	5	24	11	878.276
2013	5	24	12	881.753
2013	5	24	13	877.067
2013	5	24	14	874.079
2013	5	24	15	861.383
2013	5	24	16	848.659
2013	5	24	17	837.417
2013	5	24	18	820.535
2013	5	24	19	802.812

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	24	20	791.242
2013	5	24	21	810.000
2013	5	24	22	814.692
2013	5	24	23	757.478
2013	5	24	24	696.168
2013	5	25	1	655.906
2013	5	25	2	629.717
2013	5	25	3	615.498
2013	5	25	4	602.476
2013	5	25	5	604.355
2013	5	25	6	607.871
2013	5	25	7	622.970
2013	5	25	8	660.618
2013	5	25	9	700.929
2013	5	25	10	731.728
2013	5	25	11	740.602
2013	5	25	12	741.436
2013	5	25	13	740.571
2013	5	25	14	729.456
2013	5	25	15	719.127
2013	5	25	16	713.698
2013	5	25	17	715.731
2013	5	25	18	716.130
2013	5	25	19	720.389
2013	5	25	20	717.445
2013	5	25	21	734.375
2013	5	25	22	761.810
2013	5	25	23	716.015
2013	5	25	24	667.880
2013	5	26	1	626.984
2013	5	26	2	600.172
2013	5	26	3	586.454
2013	5	26	4	580.662
2013	5	26	5	577.602
2013	5	26	6	577.137
2013	5	26	7	581.435
2013	5	26	8	610.025
2013	5	26	9	650.674
2013	5	26	10	680.742
2013	5	26	11	697.731
2013	5	26	12	704.918
2013	5	26	13	709.075
2013	5	26	14	701.962
2013	5	26	15	697.389
2013	5	26	16	690.272
2013	5	26	17	693.040
2013	5	26	18	698.582
2013	5	26	19	694.840
2013	5	26	20	694.493
2013	5	26	21	703.213

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	26	22	739.027
2013	5	26	23	694.102
2013	5	26	24	652.657
2013	5	27	1	610.008
2013	5	27	2	584.163
2013	5	27	3	574.222
2013	5	27	4	565.353
2013	5	27	5	569.422
2013	5	27	6	575.904
2013	5	27	7	576.850
2013	5	27	8	602.953
2013	5	27	9	657.561
2013	5	27	10	683.516
2013	5	27	11	713.389
2013	5	27	12	727.295
2013	5	27	13	730.706
2013	5	27	14	731.132
2013	5	27	15	729.685
2013	5	27	16	721.867
2013	5	27	17	730.152
2013	5	27	18	731.748
2013	5	27	19	729.875
2013	5	27	20	728.981
2013	5	27	21	757.310
2013	5	27	22	769.324
2013	5	27	23	710.878
2013	5	27	24	657.086
2013	5	28	1	609.576
2013	5	28	2	596.778
2013	5	28	3	579.423
2013	5	28	4	580.597
2013	5	28	5	591.172
2013	5	28	6	635.420
2013	5	28	7	719.078
2013	5	28	8	795.167
2013	5	28	9	848.954
2013	5	28	10	883.726
2013	5	28	11	907.168
2013	5	28	12	924.583
2013	5	28	13	923.836
2013	5	28	14	932.102
2013	5	28	15	921.078
2013	5	28	16	916.308
2013	5	28	17	918.510
2013	5	28	18	906.644
2013	5	28	19	894.683
2013	5	28	20	883.983
2013	5	28	21	907.166
2013	5	28	22	874.628
2013	5	28	23	795.429

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	28	24	727.690
2013	5	29	1	678.799
2013	5	29	2	657.195
2013	5	29	3	644.335
2013	5	29	4	636.388
2013	5	29	5	647.884
2013	5	29	6	699.862
2013	5	29	7	787.440
2013	5	29	8	877.383
2013	5	29	9	925.801
2013	5	29	10	963.124
2013	5	29	11	1,017.364
2013	5	29	12	1,055.107
2013	5	29	13	1,073.701
2013	5	29	14	1,079.318
2013	5	29	15	1,077.692
2013	5	29	16	1,081.784
2013	5	29	17	1,072.559
2013	5	29	18	1,073.908
2013	5	29	19	1,042.627
2013	5	29	20	1,017.707
2013	5	29	21	1,008.994
2013	5	29	22	1,015.050
2013	5	29	23	927.529
2013	5	29	24	842.933
2013	5	30	1	775.140
2013	5	30	2	735.017
2013	5	30	3	706.595
2013	5	30	4	685.648
2013	5	30	5	691.894
2013	5	30	6	733.590
2013	5	30	7	824.290
2013	5	30	8	920.992
2013	5	30	9	1,006.552
2013	5	30	10	1,086.147
2013	5	30	11	1,149.723
2013	5	30	12	1,195.070
2013	5	30	13	1,227.961
2013	5	30	14	1,257.956
2013	5	30	15	1,269.514
2013	5	30	16	1,275.881
2013	5	30	17	1,291.301
2013	5	30	18	1,284.738
2013	5	30	19	1,267.748
2013	5	30	20	1,229.005
2013	5	30	21	1,182.772
2013	5	30	22	1,160.964
2013	5	30	23	1,055.188
2013	5	30	24	954.581
2013	5	31	1	867.273

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	5	31	2	809.448
2013	5	31	3	775.068
2013	5	31	4	754.016
2013	5	31	5	757.993
2013	5	31	6	798.062
2013	5	31	7	868.208
2013	5	31	8	978.856
2013	5	31	9	1,075.476
2013	5	31	10	1,161.124
2013	5	31	11	1,237.778
2013	5	31	12	1,287.627
2013	5	31	13	1,315.379
2013	5	31	14	1,353.255
2013	5	31	15	1,366.995
2013	5	31	16	1,385.341
2013	5	31	17	1,379.307
2013	5	31	18	1,353.313
2013	5	31	19	1,297.440
2013	5	31	20	1,226.370
2013	5	31	21	1,197.615
2013	5	31	22	1,176.651
2013	5	31	23	1,076.912
2013	5	31	24	977.460
2013	6	1	1	888.984
2013	6	1	2	827.044
2013	6	1	3	780.545
2013	6	1	4	756.278
2013	6	1	5	742.853
2013	6	1	6	737.737
2013	6	1	7	762.795
2013	6	1	8	839.877
2013	6	1	9	913.745
2013	6	1	10	983.728
2013	6	1	11	1,031.311
2013	6	1	12	1,101.495
2013	6	1	13	1,148.113
2013	6	1	14	1,186.056
2013	6	1	15	1,204.200
2013	6	1	16	1,227.948
2013	6	1	17	1,230.961
2013	6	1	18	1,226.679
2013	6	1	19	1,170.125
2013	6	1	20	1,093.011
2013	6	1	21	1,061.011
2013	6	1	22	1,042.135
2013	6	1	23	969.537
2013	6	1	24	891.025
2013	6	2	1	823.951
2013	6	2	2	777.379
2013	6	2	3	744.673

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	2	4	724.273
2013	6	2	5	718.115
2013	6	2	6	717.920
2013	6	2	7	705.817
2013	6	2	8	739.101
2013	6	2	9	792.791
2013	6	2	10	839.286
2013	6	2	11	890.839
2013	6	2	12	937.161
2013	6	2	13	952.115
2013	6	2	14	959.707
2013	6	2	15	970.543
2013	6	2	16	977.134
2013	6	2	17	981.455
2013	6	2	18	984.093
2013	6	2	19	959.604
2013	6	2	20	927.851
2013	6	2	21	910.841
2013	6	2	22	916.738
2013	6	2	23	845.402
2013	6	2	24	754.912
2013	6	3	1	697.879
2013	6	3	2	660.959
2013	6	3	3	632.341
2013	6	3	4	631.118
2013	6	3	5	636.786
2013	6	3	6	677.221
2013	6	3	7	749.009
2013	6	3	8	821.704
2013	6	3	9	860.342
2013	6	3	10	891.767
2013	6	3	11	914.221
2013	6	3	12	925.886
2013	6	3	13	931.672
2013	6	3	14	944.911
2013	6	3	15	941.023
2013	6	3	16	932.307
2013	6	3	17	929.595
2013	6	3	18	914.545
2013	6	3	19	896.109
2013	6	3	20	876.155
2013	6	3	21	869.919
2013	6	3	22	880.747
2013	6	3	23	804.072
2013	6	3	24	730.497
2013	6	4	1	675.409
2013	6	4	2	645.707
2013	6	4	3	631.783
2013	6	4	4	620.915
2013	6	4	5	632.515

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	4	6	666.509
2013	6	4	7	728.303
2013	6	4	8	807.232
2013	6	4	9	854.875
2013	6	4	10	881.087
2013	6	4	11	902.267
2013	6	4	12	910.935
2013	6	4	13	917.604
2013	6	4	14	929.934
2013	6	4	15	929.295
2013	6	4	16	930.342
2013	6	4	17	923.689
2013	6	4	18	912.712
2013	6	4	19	891.899
2013	6	4	20	870.998
2013	6	4	21	864.935
2013	6	4	22	868.309
2013	6	4	23	796.180
2013	6	4	24	731.578
2013	6	5	1	674.400
2013	6	5	2	645.387
2013	6	5	3	629.341
2013	6	5	4	623.635
2013	6	5	5	634.283
2013	6	5	6	665.138
2013	6	5	7	736.178
2013	6	5	8	807.678
2013	6	5	9	846.114
2013	6	5	10	868.285
2013	6	5	11	900.012
2013	6	5	12	914.105
2013	6	5	13	929.981
2013	6	5	14	934.134
2013	6	5	15	935.886
2013	6	5	16	933.134
2013	6	5	17	924.208
2013	6	5	18	903.731
2013	6	5	19	878.519
2013	6	5	20	850.624
2013	6	5	21	859.448
2013	6	5	22	868.710
2013	6	5	23	789.874
2013	6	5	24	723.433
2013	6	6	1	672.573
2013	6	6	2	643.854
2013	6	6	3	629.769
2013	6	6	4	623.986
2013	6	6	5	633.281
2013	6	6	6	673.030
2013	6	6	7	742.099

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	6	8	818.910
2013	6	6	9	862.552
2013	6	6	10	881.518
2013	6	6	11	910.832
2013	6	6	12	917.419
2013	6	6	13	920.790
2013	6	6	14	925.631
2013	6	6	15	921.010
2013	6	6	16	914.994
2013	6	6	17	917.314
2013	6	6	18	910.536
2013	6	6	19	899.781
2013	6	6	20	887.730
2013	6	6	21	889.432
2013	6	6	22	861.518
2013	6	6	23	790.709
2013	6	6	24	730.736
2013	6	7	1	684.439
2013	6	7	2	657.441
2013	6	7	3	642.059
2013	6	7	4	632.423
2013	6	7	5	647.986
2013	6	7	6	686.285
2013	6	7	7	753.758
2013	6	7	8	823.468
2013	6	7	9	868.399
2013	6	7	10	884.543
2013	6	7	11	906.932
2013	6	7	12	911.818
2013	6	7	13	909.578
2013	6	7	14	912.972
2013	6	7	15	903.798
2013	6	7	16	894.528
2013	6	7	17	879.212
2013	6	7	18	862.171
2013	6	7	19	847.908
2013	6	7	20	834.867
2013	6	7	21	836.213
2013	6	7	22	833.705
2013	6	7	23	766.876
2013	6	7	24	707.774
2013	6	8	1	654.803
2013	6	8	2	631.793
2013	6	8	3	608.467
2013	6	8	4	597.232
2013	6	8	5	596.132
2013	6	8	6	610.085
2013	6	8	7	624.419
2013	6	8	8	662.914
2013	6	8	9	716.609

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	8	10	756.448
2013	6	8	11	784.583
2013	6	8	12	794.334
2013	6	8	13	792.429
2013	6	8	14	789.220
2013	6	8	15	780.110
2013	6	8	16	776.317
2013	6	8	17	769.907
2013	6	8	18	770.467
2013	6	8	19	764.998
2013	6	8	20	760.189
2013	6	8	21	774.467
2013	6	8	22	787.192
2013	6	8	23	744.552
2013	6	8	24	685.820
2013	6	9	1	641.367
2013	6	9	2	610.496
2013	6	9	3	592.764
2013	6	9	4	575.862
2013	6	9	5	579.091
2013	6	9	6	567.720
2013	6	9	7	574.856
2013	6	9	8	612.329
2013	6	9	9	660.291
2013	6	9	10	708.982
2013	6	9	11	742.058
2013	6	9	12	763.236
2013	6	9	13	781.588
2013	6	9	14	790.496
2013	6	9	15	790.063
2013	6	9	16	801.728
2013	6	9	17	815.994
2013	6	9	18	835.627
2013	6	9	19	825.793
2013	6	9	20	814.743
2013	6	9	21	817.863
2013	6	9	22	838.305
2013	6	9	23	787.144
2013	6	9	24	720.075
2013	6	10	1	671.730
2013	6	10	2	643.691
2013	6	10	3	626.696
2013	6	10	4	626.523
2013	6	10	5	634.794
2013	6	10	6	682.631
2013	6	10	7	753.305
2013	6	10	8	832.022
2013	6	10	9	886.675
2013	6	10	10	925.774
2013	6	10	11	955.473

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	10	12	970.696
2013	6	10	13	981.557
2013	6	10	14	985.663
2013	6	10	15	975.511
2013	6	10	16	962.327
2013	6	10	17	954.086
2013	6	10	18	947.303
2013	6	10	19	934.844
2013	6	10	20	916.295
2013	6	10	21	918.510
2013	6	10	22	903.830
2013	6	10	23	831.819
2013	6	10	24	761.371
2013	6	11	1	710.438
2013	6	11	2	685.056
2013	6	11	3	666.533
2013	6	11	4	660.192
2013	6	11	5	666.259
2013	6	11	6	715.739
2013	6	11	7	777.927
2013	6	11	8	869.205
2013	6	11	9	909.813
2013	6	11	10	930.548
2013	6	11	11	958.085
2013	6	11	12	966.701
2013	6	11	13	968.562
2013	6	11	14	968.578
2013	6	11	15	968.656
2013	6	11	16	955.480
2013	6	11	17	950.796
2013	6	11	18	931.523
2013	6	11	19	915.809
2013	6	11	20	900.463
2013	6	11	21	906.176
2013	6	11	22	897.546
2013	6	11	23	821.767
2013	6	11	24	744.123
2013	6	12	1	693.182
2013	6	12	2	661.100
2013	6	12	3	640.531
2013	6	12	4	633.275
2013	6	12	5	642.804
2013	6	12	6	675.024
2013	6	12	7	737.183
2013	6	12	8	823.397
2013	6	12	9	876.901
2013	6	12	10	935.271
2013	6	12	11	943.021
2013	6	12	12	959.117
2013	6	12	13	973.504

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	12	14	985.062
2013	6	12	15	988.148
2013	6	12	16	993.687
2013	6	12	17	992.483
2013	6	12	18	973.746
2013	6	12	19	955.242
2013	6	12	20	926.093
2013	6	12	21	922.944
2013	6	12	22	934.087
2013	6	12	23	858.311
2013	6	12	24	785.900
2013	6	13	1	727.347
2013	6	13	2	692.899
2013	6	13	3	671.842
2013	6	13	4	661.607
2013	6	13	5	671.179
2013	6	13	6	716.278
2013	6	13	7	788.836
2013	6	13	8	861.566
2013	6	13	9	896.124
2013	6	13	10	929.614
2013	6	13	11	955.335
2013	6	13	12	965.402
2013	6	13	13	958.998
2013	6	13	14	949.255
2013	6	13	15	942.275
2013	6	13	16	929.356
2013	6	13	17	920.356
2013	6	13	18	907.502
2013	6	13	19	889.692
2013	6	13	20	867.484
2013	6	13	21	864.539
2013	6	13	22	870.623
2013	6	13	23	802.171
2013	6	13	24	739.386
2013	6	14	1	684.810
2013	6	14	2	652.661
2013	6	14	3	633.047
2013	6	14	4	622.597
2013	6	14	5	635.335
2013	6	14	6	664.799
2013	6	14	7	730.213
2013	6	14	8	803.572
2013	6	14	9	858.340
2013	6	14	10	892.343
2013	6	14	11	922.355
2013	6	14	12	930.204
2013	6	14	13	942.252
2013	6	14	14	949.393
2013	6	14	15	949.426

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	14	16	942.137
2013	6	14	17	943.590
2013	6	14	18	925.394
2013	6	14	19	898.132
2013	6	14	20	874.906
2013	6	14	21	856.415
2013	6	14	22	870.313
2013	6	14	23	817.102
2013	6	14	24	745.119
2013	6	15	1	691.570
2013	6	15	2	645.429
2013	6	15	3	622.015
2013	6	15	4	606.263
2013	6	15	5	604.589
2013	6	15	6	594.363
2013	6	15	7	606.505
2013	6	15	8	664.427
2013	6	15	9	719.515
2013	6	15	10	768.463
2013	6	15	11	800.443
2013	6	15	12	814.692
2013	6	15	13	818.725
2013	6	15	14	822.252
2013	6	15	15	817.114
2013	6	15	16	823.364
2013	6	15	17	832.518
2013	6	15	18	837.586
2013	6	15	19	831.622
2013	6	15	20	810.828
2013	6	15	21	798.515
2013	6	15	22	823.541
2013	6	15	23	784.113
2013	6	15	24	719.952
2013	6	16	1	672.141
2013	6	16	2	637.234
2013	6	16	3	614.141
2013	6	16	4	601.932
2013	6	16	5	595.038
2013	6	16	6	590.169
2013	6	16	7	598.499
2013	6	16	8	627.987
2013	6	16	9	678.664
2013	6	16	10	730.661
2013	6	16	11	757.343
2013	6	16	12	784.244
2013	6	16	13	798.775
2013	6	16	14	802.636
2013	6	16	15	809.343
2013	6	16	16	812.928
2013	6	16	17	828.424

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	16	18	844.702
2013	6	16	19	845.421
2013	6	16	20	834.915
2013	6	16	21	838.712
2013	6	16	22	864.453
2013	6	16	23	820.201
2013	6	16	24	753.405
2013	6	17	1	698.413
2013	6	17	2	661.413
2013	6	17	3	647.440
2013	6	17	4	629.349
2013	6	17	5	642.471
2013	6	17	6	686.406
2013	6	17	7	758.890
2013	6	17	8	853.050
2013	6	17	9	934.324
2013	6	17	10	986.199
2013	6	17	11	1,037.840
2013	6	17	12	1,056.508
2013	6	17	13	1,068.314
2013	6	17	14	1,069.741
2013	6	17	15	1,062.033
2013	6	17	16	1,054.348
2013	6	17	17	1,039.825
2013	6	17	18	1,033.957
2013	6	17	19	1,009.085
2013	6	17	20	973.672
2013	6	17	21	954.365
2013	6	17	22	954.184
2013	6	17	23	879.516
2013	6	17	24	794.602
2013	6	18	1	731.824
2013	6	18	2	701.450
2013	6	18	3	669.070
2013	6	18	4	659.991
2013	6	18	5	667.710
2013	6	18	6	692.614
2013	6	18	7	764.682
2013	6	18	8	822.291
2013	6	18	9	869.012
2013	6	18	10	892.588
2013	6	18	11	917.164
2013	6	18	12	943.913
2013	6	18	13	955.033
2013	6	18	14	969.160
2013	6	18	15	965.431
2013	6	18	16	966.180
2013	6	18	17	961.571
2013	6	18	18	951.346
2013	6	18	19	922.492

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	18	20	892.358
2013	6	18	21	880.141
2013	6	18	22	888.922
2013	6	18	23	817.840
2013	6	18	24	744.253
2013	6	19	1	688.510
2013	6	19	2	654.651
2013	6	19	3	638.114
2013	6	19	4	626.692
2013	6	19	5	637.650
2013	6	19	6	667.629
2013	6	19	7	719.706
2013	6	19	8	806.212
2013	6	19	9	864.079
2013	6	19	10	892.796
2013	6	19	11	924.052
2013	6	19	12	943.087
2013	6	19	13	943.365
2013	6	19	14	953.880
2013	6	19	15	948.117
2013	6	19	16	946.772
2013	6	19	17	935.641
2013	6	19	18	922.281
2013	6	19	19	895.667
2013	6	19	20	870.774
2013	6	19	21	855.254
2013	6	19	22	862.645
2013	6	19	23	804.243
2013	6	19	24	732.060
2013	6	20	1	676.636
2013	6	20	2	643.224
2013	6	20	3	625.997
2013	6	20	4	618.171
2013	6	20	5	622.211
2013	6	20	6	654.549
2013	6	20	7	712.785
2013	6	20	8	792.301
2013	6	20	9	855.421
2013	6	20	10	897.379
2013	6	20	11	936.491
2013	6	20	12	957.109
2013	6	20	13	970.178
2013	6	20	14	985.433
2013	6	20	15	988.811
2013	6	20	16	982.475
2013	6	20	17	972.545
2013	6	20	18	952.415
2013	6	20	19	923.859
2013	6	20	20	900.755
2013	6	20	21	883.062

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	20	22	888.515
2013	6	20	23	826.917
2013	6	20	24	751.413
2013	6	21	1	693.985
2013	6	21	2	656.760
2013	6	21	3	636.805
2013	6	21	4	626.431
2013	6	21	5	632.555
2013	6	21	6	656.649
2013	6	21	7	709.265
2013	6	21	8	797.407
2013	6	21	9	870.125
2013	6	21	10	924.168
2013	6	21	11	977.819
2013	6	21	12	1,003.375
2013	6	21	13	1,022.379
2013	6	21	14	1,042.649
2013	6	21	15	1,050.153
2013	6	21	16	1,058.200
2013	6	21	17	1,054.367
2013	6	21	18	1,031.245
2013	6	21	19	988.145
2013	6	21	20	955.657
2013	6	21	21	921.827
2013	6	21	22	927.385
2013	6	21	23	853.320
2013	6	21	24	785.853
2013	6	22	1	721.668
2013	6	22	2	678.449
2013	6	22	3	652.962
2013	6	22	4	644.043
2013	6	22	5	642.857
2013	6	22	6	642.065
2013	6	22	7	656.601
2013	6	22	8	721.929
2013	6	22	9	805.575
2013	6	22	10	884.790
2013	6	22	11	945.666
2013	6	22	12	1,002.431
2013	6	22	13	1,040.301
2013	6	22	14	1,060.724
2013	6	22	15	1,054.452
2013	6	22	16	1,056.337
2013	6	22	17	1,049.567
2013	6	22	18	1,047.521
2013	6	22	19	1,051.122
2013	6	22	20	1,049.155
2013	6	22	21	1,031.226
2013	6	22	22	1,045.300
2013	6	22	23	991.513

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	22	24	919.218
2013	6	23	1	850.553
2013	6	23	2	800.586
2013	6	23	3	764.810
2013	6	23	4	743.028
2013	6	23	5	730.275
2013	6	23	6	711.059
2013	6	23	7	719.610
2013	6	23	8	784.142
2013	6	23	9	891.911
2013	6	23	10	992.592
2013	6	23	11	1,081.359
2013	6	23	12	1,153.231
2013	6	23	13	1,200.256
2013	6	23	14	1,221.005
2013	6	23	15	1,229.151
2013	6	23	16	1,238.971
2013	6	23	17	1,242.814
2013	6	23	18	1,257.477
2013	6	23	19	1,245.849
2013	6	23	20	1,201.710
2013	6	23	21	1,154.280
2013	6	23	22	1,159.029
2013	6	23	23	1,078.878
2013	6	23	24	980.957
2013	6	24	1	898.358
2013	6	24	2	844.673
2013	6	24	3	810.064
2013	6	24	4	789.024
2013	6	24	5	797.201
2013	6	24	6	838.221
2013	6	24	7	920.059
2013	6	24	8	1,036.644
2013	6	24	9	1,148.700
2013	6	24	10	1,245.738
2013	6	24	11	1,321.615
2013	6	24	12	1,374.532
2013	6	24	13	1,412.057
2013	6	24	14	1,434.384
2013	6	24	15	1,458.553
2013	6	24	16	1,455.160
2013	6	24	17	1,451.659
2013	6	24	18	1,432.461
2013	6	24	19	1,393.331
2013	6	24	20	1,336.750
2013	6	24	21	1,272.936
2013	6	24	22	1,244.172
2013	6	24	23	1,143.175
2013	6	24	24	1,035.835
2013	6	25	1	942.073

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	25	2	880.781
2013	6	25	3	840.230
2013	6	25	4	820.428
2013	6	25	5	824.729
2013	6	25	6	851.877
2013	6	25	7	927.566
2013	6	25	8	1,032.779
2013	6	25	9	1,097.976
2013	6	25	10	1,150.689
2013	6	25	11	1,186.097
2013	6	25	12	1,213.937
2013	6	25	13	1,262.183
2013	6	25	14	1,279.564
2013	6	25	15	1,296.205
2013	6	25	16	1,312.582
2013	6	25	17	1,312.965
2013	6	25	18	1,318.636
2013	6	25	19	1,283.102
2013	6	25	20	1,232.211
2013	6	25	21	1,171.257
2013	6	25	22	1,163.238
2013	6	25	23	1,065.581
2013	6	25	24	963.586
2013	6	26	1	886.109
2013	6	26	2	835.893
2013	6	26	3	800.099
2013	6	26	4	789.841
2013	6	26	5	792.004
2013	6	26	6	831.438
2013	6	26	7	898.197
2013	6	26	8	992.148
2013	6	26	9	1,068.131
2013	6	26	10	1,103.165
2013	6	26	11	1,140.983
2013	6	26	12	1,226.412
2013	6	26	13	1,278.251
2013	6	26	14	1,325.209
2013	6	26	15	1,349.054
2013	6	26	16	1,329.404
2013	6	26	17	1,281.278
2013	6	26	18	1,298.863
2013	6	26	19	1,287.531
2013	6	26	20	1,244.494
2013	6	26	21	1,184.231
2013	6	26	22	1,164.897
2013	6	26	23	1,062.861
2013	6	26	24	961.163
2013	6	27	1	876.505
2013	6	27	2	817.959
2013	6	27	3	784.176

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	27	4	763.298
2013	6	27	5	766.690
2013	6	27	6	798.270
2013	6	27	7	860.498
2013	6	27	8	964.961
2013	6	27	9	1,054.356
2013	6	27	10	1,137.468
2013	6	27	11	1,191.474
2013	6	27	12	1,228.906
2013	6	27	13	1,241.420
2013	6	27	14	1,236.843
2013	6	27	15	1,224.650
2013	6	27	16	1,212.773
2013	6	27	17	1,201.881
2013	6	27	18	1,171.664
2013	6	27	19	1,138.964
2013	6	27	20	1,101.297
2013	6	27	21	1,074.378
2013	6	27	22	1,064.545
2013	6	27	23	979.732
2013	6	27	24	888.685
2013	6	28	1	822.743
2013	6	28	2	775.701
2013	6	28	3	752.285
2013	6	28	4	730.078
2013	6	28	5	741.207
2013	6	28	6	777.549
2013	6	28	7	841.632
2013	6	28	8	904.870
2013	6	28	9	964.777
2013	6	28	10	994.742
2013	6	28	11	1,021.057
2013	6	28	12	1,022.951
2013	6	28	13	1,019.964
2013	6	28	14	1,012.633
2013	6	28	15	996.736
2013	6	28	16	974.656
2013	6	28	17	949.789
2013	6	28	18	931.515
2013	6	28	19	901.237
2013	6	28	20	888.474
2013	6	28	21	884.134
2013	6	28	22	882.552
2013	6	28	23	818.959
2013	6	28	24	758.401
2013	6	29	1	705.542
2013	6	29	2	665.304
2013	6	29	3	650.430
2013	6	29	4	635.078
2013	6	29	5	640.192

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	6	29	6	643.567
2013	6	29	7	657.855
2013	6	29	8	702.664
2013	6	29	9	755.546
2013	6	29	10	809.522
2013	6	29	11	842.842
2013	6	29	12	863.990
2013	6	29	13	882.546
2013	6	29	14	895.721
2013	6	29	15	905.243
2013	6	29	16	904.299
2013	6	29	17	921.850
2013	6	29	18	936.983
2013	6	29	19	927.407
2013	6	29	20	904.296
2013	6	29	21	884.567
2013	6	29	22	889.069
2013	6	29	23	846.092
2013	6	29	24	786.591
2013	6	30	1	734.451
2013	6	30	2	691.065
2013	6	30	3	663.941
2013	6	30	4	648.194
2013	6	30	5	631.655
2013	6	30	6	625.624
2013	6	30	7	625.657
2013	6	30	8	669.881
2013	6	30	9	732.265
2013	6	30	10	795.703
2013	6	30	11	846.425
2013	6	30	12	891.390
2013	6	30	13	923.407
2013	6	30	14	940.029
2013	6	30	15	953.531
2013	6	30	16	962.864
2013	6	30	17	976.729
2013	6	30	18	984.060
2013	6	30	19	966.904
2013	6	30	20	926.501
2013	6	30	21	912.862
2013	6	30	22	926.890
2013	6	30	23	883.695
2013	6	30	24	817.497
2013	7	1	1	752.284
2013	7	1	2	710.230
2013	7	1	3	693.881
2013	7	1	4	684.303
2013	7	1	5	692.635
2013	7	1	6	722.839
2013	7	1	7	780.904

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	1	8	858.829
2013	7	1	9	921.466
2013	7	1	10	955.894
2013	7	1	11	986.601
2013	7	1	12	991.644
2013	7	1	13	997.404
2013	7	1	14	989.643
2013	7	1	15	985.656
2013	7	1	16	971.506
2013	7	1	17	962.613
2013	7	1	18	951.462
2013	7	1	19	946.196
2013	7	1	20	926.605
2013	7	1	21	916.908
2013	7	1	22	896.045
2013	7	1	23	822.763
2013	7	1	24	760.394
2013	7	2	1	708.943
2013	7	2	2	678.677
2013	7	2	3	657.367
2013	7	2	4	647.420
2013	7	2	5	659.999
2013	7	2	6	694.916
2013	7	2	7	747.523
2013	7	2	8	827.234
2013	7	2	9	884.916
2013	7	2	10	922.328
2013	7	2	11	966.259
2013	7	2	12	997.510
2013	7	2	13	1,020.093
2013	7	2	14	1,061.635
2013	7	2	15	1,081.783
2013	7	2	16	1,099.062
2013	7	2	17	1,081.518
2013	7	2	18	1,050.758
2013	7	2	19	1,016.113
2013	7	2	20	986.663
2013	7	2	21	979.035
2013	7	2	22	984.652
2013	7	2	23	917.937
2013	7	2	24	840.541
2013	7	3	1	774.385
2013	7	3	2	732.171
2013	7	3	3	710.666
2013	7	3	4	697.429
2013	7	3	5	701.707
2013	7	3	6	741.021
2013	7	3	7	795.134
2013	7	3	8	878.560
2013	7	3	9	967.710

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	3	10	1,065.419
2013	7	3	11	1,149.280
2013	7	3	12	1,216.287
2013	7	3	13	1,242.255
2013	7	3	14	1,245.495
2013	7	3	15	1,260.801
2013	7	3	16	1,276.872
2013	7	3	17	1,232.135
2013	7	3	18	1,158.100
2013	7	3	19	1,108.266
2013	7	3	20	1,074.328
2013	7	3	21	1,045.481
2013	7	3	22	1,041.540
2013	7	3	23	969.232
2013	7	3	24	887.099
2013	7	4	1	822.284
2013	7	4	2	771.469
2013	7	4	3	741.112
2013	7	4	4	720.789
2013	7	4	5	719.866
2013	7	4	6	716.216
2013	7	4	7	723.193
2013	7	4	8	759.550
2013	7	4	9	822.335
2013	7	4	10	878.587
2013	7	4	11	945.576
2013	7	4	12	981.916
2013	7	4	13	1,021.326
2013	7	4	14	1,053.814
2013	7	4	15	1,080.664
2013	7	4	16	1,110.704
2013	7	4	17	1,134.015
2013	7	4	18	1,138.834
2013	7	4	19	1,106.023
2013	7	4	20	1,052.297
2013	7	4	21	1,006.643
2013	7	4	22	996.386
2013	7	4	23	942.535
2013	7	4	24	888.983
2013	7	5	1	829.564
2013	7	5	2	779.437
2013	7	5	3	742.694
2013	7	5	4	724.780
2013	7	5	5	728.067
2013	7	5	6	753.618
2013	7	5	7	788.431
2013	7	5	8	875.541
2013	7	5	9	949.633
2013	7	5	10	1,056.800
2013	7	5	11	1,145.049

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	5	12	1,190.831
2013	7	5	13	1,214.647
2013	7	5	14	1,219.250
2013	7	5	15	1,241.069
2013	7	5	16	1,218.130
2013	7	5	17	1,210.577
2013	7	5	18	1,208.899
2013	7	5	19	1,156.480
2013	7	5	20	1,108.751
2013	7	5	21	1,074.322
2013	7	5	22	1,068.530
2013	7	5	23	993.021
2013	7	5	24	909.848
2013	7	6	1	840.141
2013	7	6	2	788.121
2013	7	6	3	747.592
2013	7	6	4	721.978
2013	7	6	5	707.897
2013	7	6	6	705.174
2013	7	6	7	714.349
2013	7	6	8	771.676
2013	7	6	9	839.059
2013	7	6	10	935.752
2013	7	6	11	1,026.767
2013	7	6	12	1,081.997
2013	7	6	13	1,118.117
2013	7	6	14	1,144.846
2013	7	6	15	1,159.506
2013	7	6	16	1,183.506
2013	7	6	17	1,186.279
2013	7	6	18	1,191.361
2013	7	6	19	1,186.672
2013	7	6	20	1,155.897
2013	7	6	21	1,108.444
2013	7	6	22	1,097.908
2013	7	6	23	1,029.597
2013	7	6	24	952.653
2013	7	7	1	888.038
2013	7	7	2	837.469
2013	7	7	3	798.452
2013	7	7	4	767.136
2013	7	7	5	742.439
2013	7	7	6	737.126
2013	7	7	7	732.403
2013	7	7	8	786.533
2013	7	7	9	877.166
2013	7	7	10	968.537
2013	7	7	11	1,031.658
2013	7	7	12	1,092.221
2013	7	7	13	1,123.008

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	7	14	1,150.751
2013	7	7	15	1,166.911
2013	7	7	16	1,174.730
2013	7	7	17	1,201.190
2013	7	7	18	1,180.100
2013	7	7	19	1,166.807
2013	7	7	20	1,127.966
2013	7	7	21	1,096.425
2013	7	7	22	1,094.836
2013	7	7	23	1,022.181
2013	7	7	24	932.134
2013	7	8	1	860.028
2013	7	8	2	812.171
2013	7	8	3	793.838
2013	7	8	4	771.855
2013	7	8	5	788.543
2013	7	8	6	835.576
2013	7	8	7	908.108
2013	7	8	8	994.759
2013	7	8	9	1,065.958
2013	7	8	10	1,114.763
2013	7	8	11	1,192.696
2013	7	8	12	1,270.643
2013	7	8	13	1,313.494
2013	7	8	14	1,352.713
2013	7	8	15	1,368.473
2013	7	8	16	1,376.780
2013	7	8	17	1,379.638
2013	7	8	18	1,354.208
2013	7	8	19	1,293.054
2013	7	8	20	1,235.210
2013	7	8	21	1,196.505
2013	7	8	22	1,186.177
2013	7	8	23	1,088.070
2013	7	8	24	986.201
2013	7	9	1	901.783
2013	7	9	2	864.832
2013	7	9	3	823.242
2013	7	9	4	810.816
2013	7	9	5	816.516
2013	7	9	6	866.469
2013	7	9	7	927.183
2013	7	9	8	1,013.600
2013	7	9	9	1,077.810
2013	7	9	10	1,144.712
2013	7	9	11	1,214.802
2013	7	9	12	1,271.085
2013	7	9	13	1,319.091
2013	7	9	14	1,347.093
2013	7	9	15	1,312.870

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	9	16	1,316.295
2013	7	9	17	1,333.452
2013	7	9	18	1,327.784
2013	7	9	19	1,279.615
2013	7	9	20	1,234.576
2013	7	9	21	1,206.439
2013	7	9	22	1,199.779
2013	7	9	23	1,106.163
2013	7	9	24	1,014.435
2013	7	10	1	927.460
2013	7	10	2	877.336
2013	7	10	3	841.081
2013	7	10	4	822.667
2013	7	10	5	833.051
2013	7	10	6	878.679
2013	7	10	7	949.434
2013	7	10	8	1,050.756
2013	7	10	9	1,127.066
2013	7	10	10	1,188.363
2013	7	10	11	1,237.599
2013	7	10	12	1,286.392
2013	7	10	13	1,351.271
2013	7	10	14	1,404.705
2013	7	10	15	1,440.960
2013	7	10	16	1,470.744
2013	7	10	17	1,476.699
2013	7	10	18	1,441.892
2013	7	10	19	1,369.540
2013	7	10	20	1,321.272
2013	7	10	21	1,290.487
2013	7	10	22	1,232.321
2013	7	10	23	1,122.218
2013	7	10	24	1,018.217
2013	7	11	1	933.585
2013	7	11	2	877.011
2013	7	11	3	822.751
2013	7	11	4	789.976
2013	7	11	5	786.168
2013	7	11	6	808.045
2013	7	11	7	854.219
2013	7	11	8	939.656
2013	7	11	9	1,003.756
2013	7	11	10	1,045.669
2013	7	11	11	1,085.562
2013	7	11	12	1,112.505
2013	7	11	13	1,129.575
2013	7	11	14	1,160.609
2013	7	11	15	1,176.908
2013	7	11	16	1,191.016
2013	7	11	17	1,193.717

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	11	18	1,174.794
2013	7	11	19	1,148.202
2013	7	11	20	1,099.269
2013	7	11	21	1,055.396
2013	7	11	22	1,051.030
2013	7	11	23	979.261
2013	7	11	24	892.280
2013	7	12	1	821.056
2013	7	12	2	771.858
2013	7	12	3	742.945
2013	7	12	4	725.991
2013	7	12	5	733.311
2013	7	12	6	765.863
2013	7	12	7	815.578
2013	7	12	8	889.482
2013	7	12	9	957.691
2013	7	12	10	1,001.795
2013	7	12	11	1,050.584
2013	7	12	12	1,085.868
2013	7	12	13	1,107.429
2013	7	12	14	1,130.250
2013	7	12	15	1,130.429
2013	7	12	16	1,114.854
2013	7	12	17	1,086.754
2013	7	12	18	1,046.214
2013	7	12	19	1,004.129
2013	7	12	20	967.321
2013	7	12	21	951.757
2013	7	12	22	961.411
2013	7	12	23	895.497
2013	7	12	24	828.939
2013	7	13	1	761.973
2013	7	13	2	723.410
2013	7	13	3	693.426
2013	7	13	4	682.389
2013	7	13	5	677.911
2013	7	13	6	680.570
2013	7	13	7	696.047
2013	7	13	8	741.726
2013	7	13	9	808.867
2013	7	13	10	892.170
2013	7	13	11	959.560
2013	7	13	12	1,004.613
2013	7	13	13	1,022.590
2013	7	13	14	1,033.700
2013	7	13	15	1,051.180
2013	7	13	16	1,071.880
2013	7	13	17	1,087.256
2013	7	13	18	1,082.881
2013	7	13	19	1,080.015

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	13	20	1,059.531
2013	7	13	21	1,045.987
2013	7	13	22	1,054.314
2013	7	13	23	1,005.013
2013	7	13	24	925.918
2013	7	14	1	853.239
2013	7	14	2	797.039
2013	7	14	3	759.847
2013	7	14	4	735.693
2013	7	14	5	720.150
2013	7	14	6	714.640
2013	7	14	7	715.272
2013	7	14	8	777.849
2013	7	14	9	886.978
2013	7	14	10	986.955
2013	7	14	11	1,080.563
2013	7	14	12	1,155.364
2013	7	14	13	1,203.439
2013	7	14	14	1,241.714
2013	7	14	15	1,277.305
2013	7	14	16	1,291.659
2013	7	14	17	1,308.359
2013	7	14	18	1,317.143
2013	7	14	19	1,291.971
2013	7	14	20	1,254.612
2013	7	14	21	1,208.355
2013	7	14	22	1,205.881
2013	7	14	23	1,128.984
2013	7	14	24	1,033.299
2013	7	15	1	951.688
2013	7	15	2	901.728
2013	7	15	3	871.268
2013	7	15	4	850.991
2013	7	15	5	866.945
2013	7	15	6	909.831
2013	7	15	7	987.260
2013	7	15	8	1,084.908
2013	7	15	9	1,175.905
2013	7	15	10	1,246.978
2013	7	15	11	1,326.498
2013	7	15	12	1,383.670
2013	7	15	13	1,441.859
2013	7	15	14	1,487.936
2013	7	15	15	1,514.454
2013	7	15	16	1,514.888
2013	7	15	17	1,523.416
2013	7	15	18	1,512.242
2013	7	15	19	1,467.219
2013	7	15	20	1,402.465
2013	7	15	21	1,332.422

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	15	22	1,294.388
2013	7	15	23	1,184.312
2013	7	15	24	1,079.247
2013	7	16	1	981.831
2013	7	16	2	918.253
2013	7	16	3	871.066
2013	7	16	4	848.010
2013	7	16	5	854.874
2013	7	16	6	885.081
2013	7	16	7	951.481
2013	7	16	8	1,072.539
2013	7	16	9	1,192.046
2013	7	16	10	1,291.236
2013	7	16	11	1,371.938
2013	7	16	12	1,442.789
2013	7	16	13	1,486.259
2013	7	16	14	1,520.188
2013	7	16	15	1,547.231
2013	7	16	16	1,559.187
2013	7	16	17	1,555.079
2013	7	16	18	1,535.708
2013	7	16	19	1,493.255
2013	7	16	20	1,432.783
2013	7	16	21	1,369.302
2013	7	16	22	1,340.224
2013	7	16	23	1,223.986
2013	7	16	24	1,122.242
2013	7	17	1	1,024.368
2013	7	17	2	963.825
2013	7	17	3	916.962
2013	7	17	4	898.404
2013	7	17	5	902.016
2013	7	17	6	942.428
2013	7	17	7	1,005.315
2013	7	17	8	1,126.143
2013	7	17	9	1,240.946
2013	7	17	10	1,350.100
2013	7	17	11	1,449.474
2013	7	17	12	1,524.284
2013	7	17	13	1,585.727
2013	7	17	14	1,611.524
2013	7	17	15	1,638.750
2013	7	17	16	1,632.098
2013	7	17	17	1,644.384
2013	7	17	18	1,625.774
2013	7	17	19	1,584.382
2013	7	17	20	1,524.777
2013	7	17	21	1,476.968
2013	7	17	22	1,457.570
2013	7	17	23	1,351.676

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	17	24	1,248.259
2013	7	18	1	1,161.006
2013	7	18	2	1,086.853
2013	7	18	3	1,039.167
2013	7	18	4	1,002.302
2013	7	18	5	1,004.138
2013	7	18	6	1,034.193
2013	7	18	7	1,097.915
2013	7	18	8	1,219.892
2013	7	18	9	1,318.007
2013	7	18	10	1,422.755
2013	7	18	11	1,502.533
2013	7	18	12	1,558.066
2013	7	18	13	1,557.533
2013	7	18	14	1,548.420
2013	7	18	15	1,467.873
2013	7	18	16	1,483.336
2013	7	18	17	1,494.624
2013	7	18	18	1,509.566
2013	7	18	19	1,501.629
2013	7	18	20	1,463.182
2013	7	18	21	1,414.343
2013	7	18	22	1,396.718
2013	7	18	23	1,293.040
2013	7	18	24	1,179.756
2013	7	19	1	1,098.066
2013	7	19	2	1,033.269
2013	7	19	3	991.240
2013	7	19	4	963.339
2013	7	19	5	968.134
2013	7	19	6	1,013.535
2013	7	19	7	1,058.560
2013	7	19	8	1,183.696
2013	7	19	9	1,313.542
2013	7	19	10	1,415.716
2013	7	19	11	1,510.699
2013	7	19	12	1,559.266
2013	7	19	13	1,575.739
2013	7	19	14	1,583.482
2013	7	19	15	1,580.239
2013	7	19	16	1,576.876
2013	7	19	17	1,567.230
2013	7	19	18	1,535.884
2013	7	19	19	1,503.006
2013	7	19	20	1,446.140
2013	7	19	21	1,281.857
2013	7	19	22	1,209.846
2013	7	19	23	1,121.796
2013	7	19	24	1,014.209
2013	7	20	1	921.813

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	20	2	870.764
2013	7	20	3	829.414
2013	7	20	4	813.907
2013	7	20	5	799.804
2013	7	20	6	811.275
2013	7	20	7	818.530
2013	7	20	8	853.505
2013	7	20	9	917.537
2013	7	20	10	983.619
2013	7	20	11	1,031.286
2013	7	20	12	1,029.296
2013	7	20	13	1,029.546
2013	7	20	14	1,003.059
2013	7	20	15	1,019.893
2013	7	20	16	1,058.189
2013	7	20	17	1,075.040
2013	7	20	18	1,078.872
2013	7	20	19	1,064.206
2013	7	20	20	1,047.638
2013	7	20	21	1,009.168
2013	7	20	22	1,016.874
2013	7	20	23	964.809
2013	7	20	24	892.876
2013	7	21	1	821.944
2013	7	21	2	772.097
2013	7	21	3	737.185
2013	7	21	4	717.799
2013	7	21	5	704.549
2013	7	21	6	699.159
2013	7	21	7	691.689
2013	7	21	8	726.338
2013	7	21	9	783.083
2013	7	21	10	847.926
2013	7	21	11	900.184
2013	7	21	12	939.987
2013	7	21	13	965.866
2013	7	21	14	980.451
2013	7	21	15	989.466
2013	7	21	16	1,001.141
2013	7	21	17	1,002.520
2013	7	21	18	997.564
2013	7	21	19	968.773
2013	7	21	20	941.543
2013	7	21	21	920.472
2013	7	21	22	935.004
2013	7	21	23	881.939
2013	7	21	24	812.322
2013	7	22	1	757.512
2013	7	22	2	713.143
2013	7	22	3	700.995

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	22	4	687.609
2013	7	22	5	698.226
2013	7	22	6	743.817
2013	7	22	7	790.377
2013	7	22	8	873.325
2013	7	22	9	950.459
2013	7	22	10	1,004.401
2013	7	22	11	1,057.884
2013	7	22	12	1,109.160
2013	7	22	13	1,154.576
2013	7	22	14	1,190.724
2013	7	22	15	1,205.585
2013	7	22	16	1,202.956
2013	7	22	17	1,196.058
2013	7	22	18	1,158.789
2013	7	22	19	1,122.947
2013	7	22	20	1,087.527
2013	7	22	21	1,083.858
2013	7	22	22	1,073.620
2013	7	22	23	985.204
2013	7	22	24	913.787
2013	7	23	1	849.539
2013	7	23	2	809.243
2013	7	23	3	784.334
2013	7	23	4	764.596
2013	7	23	5	776.548
2013	7	23	6	822.825
2013	7	23	7	879.445
2013	7	23	8	949.439
2013	7	23	9	1,033.988
2013	7	23	10	1,105.592
2013	7	23	11	1,173.050
2013	7	23	12	1,230.548
2013	7	23	13	1,267.697
2013	7	23	14	1,311.584
2013	7	23	15	1,342.274
2013	7	23	16	1,358.392
2013	7	23	17	1,350.542
2013	7	23	18	1,324.139
2013	7	23	19	1,256.478
2013	7	23	20	1,214.762
2013	7	23	21	1,188.663
2013	7	23	22	1,159.498
2013	7	23	23	1,048.955
2013	7	23	24	939.853
2013	7	24	1	858.257
2013	7	24	2	806.319
2013	7	24	3	765.455
2013	7	24	4	752.462
2013	7	24	5	756.064

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	24	6	787.466
2013	7	24	7	814.103
2013	7	24	8	865.455
2013	7	24	9	909.602
2013	7	24	10	932.950
2013	7	24	11	950.678
2013	7	24	12	957.853
2013	7	24	13	964.461
2013	7	24	14	973.441
2013	7	24	15	971.580
2013	7	24	16	988.433
2013	7	24	17	982.725
2013	7	24	18	973.715
2013	7	24	19	955.615
2013	7	24	20	922.125
2013	7	24	21	905.474
2013	7	24	22	912.348
2013	7	24	23	847.461
2013	7	24	24	778.751
2013	7	25	1	719.387
2013	7	25	2	692.223
2013	7	25	3	666.461
2013	7	25	4	659.619
2013	7	25	5	665.514
2013	7	25	6	700.273
2013	7	25	7	745.292
2013	7	25	8	818.387
2013	7	25	9	884.481
2013	7	25	10	933.121
2013	7	25	11	978.030
2013	7	25	12	991.879
2013	7	25	13	1,006.450
2013	7	25	14	1,028.569
2013	7	25	15	1,032.369
2013	7	25	16	1,034.112
2013	7	25	17	1,031.797
2013	7	25	18	1,019.832
2013	7	25	19	993.650
2013	7	25	20	952.937
2013	7	25	21	937.660
2013	7	25	22	938.593
2013	7	25	23	869.386
2013	7	25	24	793.589
2013	7	26	1	734.783
2013	7	26	2	699.050
2013	7	26	3	679.244
2013	7	26	4	663.569
2013	7	26	5	669.403
2013	7	26	6	699.439
2013	7	26	7	739.409

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	26	8	810.225
2013	7	26	9	881.088
2013	7	26	10	940.240
2013	7	26	11	984.616
2013	7	26	12	1,007.256
2013	7	26	13	1,022.052
2013	7	26	14	1,044.159
2013	7	26	15	1,047.340
2013	7	26	16	1,050.282
2013	7	26	17	1,043.672
2013	7	26	18	1,028.284
2013	7	26	19	1,000.403
2013	7	26	20	957.643
2013	7	26	21	928.005
2013	7	26	22	925.317
2013	7	26	23	857.896
2013	7	26	24	788.224
2013	7	27	1	730.487
2013	7	27	2	694.170
2013	7	27	3	670.176
2013	7	27	4	653.188
2013	7	27	5	653.285
2013	7	27	6	662.406
2013	7	27	7	663.454
2013	7	27	8	715.376
2013	7	27	9	768.628
2013	7	27	10	831.787
2013	7	27	11	895.876
2013	7	27	12	931.090
2013	7	27	13	958.425
2013	7	27	14	978.223
2013	7	27	15	983.124
2013	7	27	16	978.137
2013	7	27	17	978.915
2013	7	27	18	972.444
2013	7	27	19	952.717
2013	7	27	20	947.407
2013	7	27	21	950.224
2013	7	27	22	944.907
2013	7	27	23	892.431
2013	7	27	24	830.997
2013	7	28	1	776.502
2013	7	28	2	732.877
2013	7	28	3	710.881
2013	7	28	4	693.732
2013	7	28	5	681.145
2013	7	28	6	686.612
2013	7	28	7	681.183
2013	7	28	8	711.204
2013	7	28	9	768.867

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	28	10	809.847
2013	7	28	11	823.795
2013	7	28	12	851.979
2013	7	28	13	883.352
2013	7	28	14	897.977
2013	7	28	15	892.063
2013	7	28	16	884.201
2013	7	28	17	899.088
2013	7	28	18	903.265
2013	7	28	19	887.827
2013	7	28	20	872.900
2013	7	28	21	866.465
2013	7	28	22	872.786
2013	7	28	23	813.965
2013	7	28	24	747.332
2013	7	29	1	700.599
2013	7	29	2	662.462
2013	7	29	3	641.673
2013	7	29	4	634.902
2013	7	29	5	643.669
2013	7	29	6	687.928
2013	7	29	7	740.940
2013	7	29	8	808.705
2013	7	29	9	864.033
2013	7	29	10	915.443
2013	7	29	11	962.499
2013	7	29	12	991.365
2013	7	29	13	993.190
2013	7	29	14	1,004.389
2013	7	29	15	1,006.221
2013	7	29	16	1,000.740
2013	7	29	17	971.956
2013	7	29	18	960.259
2013	7	29	19	941.212
2013	7	29	20	918.696
2013	7	29	21	916.786
2013	7	29	22	914.147
2013	7	29	23	847.032
2013	7	29	24	778.243
2013	7	30	1	725.685
2013	7	30	2	689.323
2013	7	30	3	667.468
2013	7	30	4	658.412
2013	7	30	5	656.208
2013	7	30	6	701.387
2013	7	30	7	748.139
2013	7	30	8	825.047
2013	7	30	9	877.425
2013	7	30	10	932.825
2013	7	30	11	975.264

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	7	30	12	999.028
2013	7	30	13	1,013.831
2013	7	30	14	1,034.384
2013	7	30	15	1,040.308
2013	7	30	16	1,046.501
2013	7	30	17	1,037.595
2013	7	30	18	1,027.557
2013	7	30	19	1,000.964
2013	7	30	20	969.024
2013	7	30	21	953.263
2013	7	30	22	948.240
2013	7	30	23	876.427
2013	7	30	24	800.199
2013	7	31	1	738.906
2013	7	31	2	700.095
2013	7	31	3	678.838
2013	7	31	4	660.850
2013	7	31	5	674.384
2013	7	31	6	709.498
2013	7	31	7	747.824
2013	7	31	8	828.544
2013	7	31	9	897.707
2013	7	31	10	951.640
2013	7	31	11	1,000.018
2013	7	31	12	1,040.034
2013	7	31	13	1,069.433
2013	7	31	14	1,096.544
2013	7	31	15	1,116.202
2013	7	31	16	1,124.343
2013	7	31	17	1,125.482
2013	7	31	18	1,102.298
2013	7	31	19	1,063.811
2013	7	31	20	1,032.610
2013	7	31	21	1,029.680
2013	7	31	22	1,020.880
2013	7	31	23	944.886
2013	7	31	24	864.374
2013	8	1	1	796.299
2013	8	1	2	753.470
2013	8	1	3	721.033
2013	8	1	4	715.837
2013	8	1	5	720.085
2013	8	1	6	768.534
2013	8	1	7	825.492
2013	8	1	8	898.111
2013	8	1	9	951.873
2013	8	1	10	989.309
2013	8	1	11	1,031.841
2013	8	1	12	1,073.931
2013	8	1	13	1,095.441

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	1	14	1,109.574
2013	8	1	15	1,110.162
2013	8	1	16	1,116.053
2013	8	1	17	1,113.107
2013	8	1	18	1,094.972
2013	8	1	19	1,063.663
2013	8	1	20	1,016.077
2013	8	1	21	1,004.288
2013	8	1	22	993.024
2013	8	1	23	919.328
2013	8	1	24	841.586
2013	8	2	1	774.658
2013	8	2	2	735.414
2013	8	2	3	701.829
2013	8	2	4	693.430
2013	8	2	5	691.403
2013	8	2	6	727.162
2013	8	2	7	769.848
2013	8	2	8	844.011
2013	8	2	9	922.333
2013	8	2	10	983.510
2013	8	2	11	1,029.893
2013	8	2	12	1,043.894
2013	8	2	13	1,025.376
2013	8	2	14	1,016.904
2013	8	2	15	1,013.526
2013	8	2	16	1,021.271
2013	8	2	17	1,002.935
2013	8	2	18	983.914
2013	8	2	19	962.256
2013	8	2	20	931.303
2013	8	2	21	919.530
2013	8	2	22	911.626
2013	8	2	23	855.148
2013	8	2	24	781.190
2013	8	3	1	724.361
2013	8	3	2	690.375
2013	8	3	3	664.170
2013	8	3	4	649.031
2013	8	3	5	651.658
2013	8	3	6	655.874
2013	8	3	7	661.330
2013	8	3	8	703.572
2013	8	3	9	768.339
2013	8	3	10	828.557
2013	8	3	11	866.228
2013	8	3	12	887.787
2013	8	3	13	903.981
2013	8	3	14	905.491
2013	8	3	15	905.412

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	3	16	911.765
2013	8	3	17	917.039
2013	8	3	18	921.899
2013	8	3	19	904.044
2013	8	3	20	873.015
2013	8	3	21	884.225
2013	8	3	22	881.697
2013	8	3	23	829.093
2013	8	3	24	770.629
2013	8	4	1	707.563
2013	8	4	2	672.106
2013	8	4	3	645.433
2013	8	4	4	629.883
2013	8	4	5	621.304
2013	8	4	6	620.675
2013	8	4	7	617.372
2013	8	4	8	641.868
2013	8	4	9	698.458
2013	8	4	10	750.540
2013	8	4	11	789.132
2013	8	4	12	812.101
2013	8	4	13	826.630
2013	8	4	14	832.958
2013	8	4	15	830.962
2013	8	4	16	834.040
2013	8	4	17	837.437
2013	8	4	18	852.178
2013	8	4	19	842.084
2013	8	4	20	822.540
2013	8	4	21	827.351
2013	8	4	22	831.261
2013	8	4	23	780.353
2013	8	4	24	719.599
2013	8	5	1	668.343
2013	8	5	2	641.773
2013	8	5	3	622.812
2013	8	5	4	618.811
2013	8	5	5	628.134
2013	8	5	6	670.014
2013	8	5	7	721.271
2013	8	5	8	798.690
2013	8	5	9	865.099
2013	8	5	10	919.019
2013	8	5	11	959.069
2013	8	5	12	978.666
2013	8	5	13	997.303
2013	8	5	14	1,010.480
2013	8	5	15	1,016.974
2013	8	5	16	1,021.278
2013	8	5	17	1,007.248

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	5	18	995.691
2013	8	5	19	971.138
2013	8	5	20	936.029
2013	8	5	21	939.047
2013	8	5	22	930.039
2013	8	5	23	852.281
2013	8	5	24	778.096
2013	8	6	1	726.257
2013	8	6	2	690.104
2013	8	6	3	667.315
2013	8	6	4	658.708
2013	8	6	5	667.468
2013	8	6	6	702.879
2013	8	6	7	748.139
2013	8	6	8	813.107
2013	8	6	9	876.074
2013	8	6	10	925.148
2013	8	6	11	969.469
2013	8	6	12	994.269
2013	8	6	13	1,010.304
2013	8	6	14	1,039.484
2013	8	6	15	1,057.979
2013	8	6	16	1,072.932
2013	8	6	17	1,073.781
2013	8	6	18	1,069.705
2013	8	6	19	1,047.051
2013	8	6	20	1,013.877
2013	8	6	21	1,006.875
2013	8	6	22	997.097
2013	8	6	23	918.618
2013	8	6	24	843.405
2013	8	7	1	782.140
2013	8	7	2	744.773
2013	8	7	3	722.358
2013	8	7	4	709.855
2013	8	7	5	720.081
2013	8	7	6	759.220
2013	8	7	7	812.407
2013	8	7	8	887.196
2013	8	7	9	971.413
2013	8	7	10	1,037.670
2013	8	7	11	1,082.789
2013	8	7	12	1,126.277
2013	8	7	13	1,158.571
2013	8	7	14	1,185.851
2013	8	7	15	1,191.764
2013	8	7	16	1,203.769
2013	8	7	17	1,186.525
2013	8	7	18	1,171.277
2013	8	7	19	1,138.221

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	7	20	1,108.847
2013	8	7	21	1,098.323
2013	8	7	22	1,084.766
2013	8	7	23	1,003.826
2013	8	7	24	915.151
2013	8	8	1	850.390
2013	8	8	2	796.432
2013	8	8	3	772.627
2013	8	8	4	751.501
2013	8	8	5	761.921
2013	8	8	6	807.000
2013	8	8	7	873.175
2013	8	8	8	935.512
2013	8	8	9	1,029.040
2013	8	8	10	1,104.186
2013	8	8	11	1,168.369
2013	8	8	12	1,208.269
2013	8	8	13	1,233.030
2013	8	8	14	1,248.005
2013	8	8	15	1,300.881
2013	8	8	16	1,298.993
2013	8	8	17	1,271.861
2013	8	8	18	1,243.745
2013	8	8	19	1,202.590
2013	8	8	20	1,165.892
2013	8	8	21	1,167.661
2013	8	8	22	1,140.515
2013	8	8	23	1,055.051
2013	8	8	24	964.384
2013	8	9	1	895.249
2013	8	9	2	843.733
2013	8	9	3	813.892
2013	8	9	4	793.818
2013	8	9	5	801.661
2013	8	9	6	849.968
2013	8	9	7	913.768
2013	8	9	8	979.425
2013	8	9	9	1,038.020
2013	8	9	10	1,073.675
2013	8	9	11	1,090.827
2013	8	9	12	1,088.904
2013	8	9	13	1,085.003
2013	8	9	14	1,090.154
2013	8	9	15	1,104.846
2013	8	9	16	1,122.582
2013	8	9	17	1,128.982
2013	8	9	18	1,121.410
2013	8	9	19	1,081.397
2013	8	9	20	1,019.151
2013	8	9	21	994.760

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	9	22	980.809
2013	8	9	23	904.077
2013	8	9	24	836.872
2013	8	10	1	767.684
2013	8	10	2	723.655
2013	8	10	3	694.861
2013	8	10	4	678.836
2013	8	10	5	673.430
2013	8	10	6	685.821
2013	8	10	7	685.307
2013	8	10	8	727.157
2013	8	10	9	785.972
2013	8	10	10	844.205
2013	8	10	11	879.360
2013	8	10	12	889.263
2013	8	10	13	896.093
2013	8	10	14	899.147
2013	8	10	15	899.413
2013	8	10	16	904.667
2013	8	10	17	908.904
2013	8	10	18	903.777
2013	8	10	19	890.774
2013	8	10	20	865.574
2013	8	10	21	860.648
2013	8	10	22	851.241
2013	8	10	23	794.886
2013	8	10	24	737.372
2013	8	11	1	680.999
2013	8	11	2	649.335
2013	8	11	3	631.683
2013	8	11	4	615.549
2013	8	11	5	608.659
2013	8	11	6	618.455
2013	8	11	7	605.238
2013	8	11	8	642.664
2013	8	11	9	693.081
2013	8	11	10	747.268
2013	8	11	11	793.140
2013	8	11	12	817.567
2013	8	11	13	838.571
2013	8	11	14	854.290
2013	8	11	15	862.400
2013	8	11	16	871.867
2013	8	11	17	893.148
2013	8	11	18	912.453
2013	8	11	19	895.906
2013	8	11	20	875.559
2013	8	11	21	885.869
2013	8	11	22	880.096
2013	8	11	23	820.711

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	11	24	759.648
2013	8	12	1	718.309
2013	8	12	2	684.802
2013	8	12	3	666.903
2013	8	12	4	661.176
2013	8	12	5	672.036
2013	8	12	6	720.171
2013	8	12	7	770.492
2013	8	12	8	846.755
2013	8	12	9	920.198
2013	8	12	10	976.160
2013	8	12	11	1,033.190
2013	8	12	12	1,069.943
2013	8	12	13	1,093.100
2013	8	12	14	1,123.182
2013	8	12	15	1,115.885
2013	8	12	16	1,094.685
2013	8	12	17	1,080.837
2013	8	12	18	1,060.430
2013	8	12	19	1,036.253
2013	8	12	20	1,005.670
2013	8	12	21	1,017.983
2013	8	12	22	990.650
2013	8	12	23	912.963
2013	8	12	24	839.521
2013	8	13	1	782.915
2013	8	13	2	748.850
2013	8	13	3	727.116
2013	8	13	4	718.622
2013	8	13	5	723.925
2013	8	13	6	770.465
2013	8	13	7	829.234
2013	8	13	8	889.797
2013	8	13	9	956.531
2013	8	13	10	1,013.896
2013	8	13	11	1,053.900
2013	8	13	12	1,077.692
2013	8	13	13	1,080.260
2013	8	13	14	1,094.858
2013	8	13	15	1,091.204
2013	8	13	16	1,071.531
2013	8	13	17	1,052.079
2013	8	13	18	1,011.416
2013	8	13	19	955.289
2013	8	13	20	920.767
2013	8	13	21	935.329
2013	8	13	22	899.377
2013	8	13	23	831.322
2013	8	13	24	760.633
2013	8	14	1	713.881

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	14	2	680.582
2013	8	14	3	663.673
2013	8	14	4	656.365
2013	8	14	5	660.615
2013	8	14	6	701.854
2013	8	14	7	758.290
2013	8	14	8	809.889
2013	8	14	9	863.206
2013	8	14	10	899.942
2013	8	14	11	929.559
2013	8	14	12	937.170
2013	8	14	13	949.659
2013	8	14	14	959.104
2013	8	14	15	957.392
2013	8	14	16	960.070
2013	8	14	17	949.878
2013	8	14	18	934.733
2013	8	14	19	914.563
2013	8	14	20	887.842
2013	8	14	21	898.230
2013	8	14	22	888.079
2013	8	14	23	817.499
2013	8	14	24	753.193
2013	8	15	1	698.034
2013	8	15	2	670.225
2013	8	15	3	649.540
2013	8	15	4	636.511
2013	8	15	5	649.024
2013	8	15	6	686.517
2013	8	15	7	730.779
2013	8	15	8	791.162
2013	8	15	9	855.902
2013	8	15	10	901.001
2013	8	15	11	945.424
2013	8	15	12	968.758
2013	8	15	13	978.342
2013	8	15	14	997.852
2013	8	15	15	1,004.025
2013	8	15	16	994.627
2013	8	15	17	983.324
2013	8	15	18	966.171
2013	8	15	19	947.611
2013	8	15	20	912.809
2013	8	15	21	922.042
2013	8	15	22	908.373
2013	8	15	23	835.921
2013	8	15	24	768.363
2013	8	16	1	716.519
2013	8	16	2	678.461
2013	8	16	3	658.418

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	16	4	648.105
2013	8	16	5	657.506
2013	8	16	6	696.338
2013	8	16	7	732.367
2013	8	16	8	794.421
2013	8	16	9	854.461
2013	8	16	10	907.820
2013	8	16	11	948.985
2013	8	16	12	976.024
2013	8	16	13	988.661
2013	8	16	14	1,000.547
2013	8	16	15	1,008.690
2013	8	16	16	1,009.688
2013	8	16	17	1,008.755
2013	8	16	18	993.644
2013	8	16	19	958.203
2013	8	16	20	922.788
2013	8	16	21	933.522
2013	8	16	22	912.710
2013	8	16	23	837.755
2013	8	16	24	768.501
2013	8	17	1	716.950
2013	8	17	2	677.609
2013	8	17	3	654.456
2013	8	17	4	637.775
2013	8	17	5	635.745
2013	8	17	6	645.015
2013	8	17	7	652.999
2013	8	17	8	685.687
2013	8	17	9	750.538
2013	8	17	10	810.218
2013	8	17	11	855.976
2013	8	17	12	897.515
2013	8	17	13	915.975
2013	8	17	14	932.387
2013	8	17	15	940.342
2013	8	17	16	949.134
2013	8	17	17	951.839
2013	8	17	18	955.578
2013	8	17	19	938.408
2013	8	17	20	907.174
2013	8	17	21	909.697
2013	8	17	22	895.540
2013	8	17	23	840.095
2013	8	17	24	768.457
2013	8	18	1	718.796
2013	8	18	2	683.073
2013	8	18	3	653.867
2013	8	18	4	644.172
2013	8	18	5	633.358

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	18	6	639.965
2013	8	18	7	639.950
2013	8	18	8	652.624
2013	8	18	9	705.063
2013	8	18	10	754.137
2013	8	18	11	806.662
2013	8	18	12	852.643
2013	8	18	13	889.510
2013	8	18	14	911.390
2013	8	18	15	931.452
2013	8	18	16	948.494
2013	8	18	17	971.949
2013	8	18	18	986.341
2013	8	18	19	971.357
2013	8	18	20	942.335
2013	8	18	21	960.516
2013	8	18	22	942.120
2013	8	18	23	877.242
2013	8	18	24	810.782
2013	8	19	1	751.281
2013	8	19	2	714.964
2013	8	19	3	695.532
2013	8	19	4	687.697
2013	8	19	5	694.612
2013	8	19	6	744.677
2013	8	19	7	797.856
2013	8	19	8	864.719
2013	8	19	9	940.643
2013	8	19	10	1,015.931
2013	8	19	11	1,080.654
2013	8	19	12	1,124.716
2013	8	19	13	1,152.232
2013	8	19	14	1,176.302
2013	8	19	15	1,197.046
2013	8	19	16	1,201.442
2013	8	19	17	1,209.206
2013	8	19	18	1,194.189
2013	8	19	19	1,163.369
2013	8	19	20	1,110.298
2013	8	19	21	1,102.408
2013	8	19	22	1,060.079
2013	8	19	23	961.102
2013	8	19	24	873.488
2013	8	20	1	808.361
2013	8	20	2	764.739
2013	8	20	3	731.206
2013	8	20	4	723.911
2013	8	20	5	723.302
2013	8	20	6	765.500
2013	8	20	7	816.423

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	20	8	873.467
2013	8	20	9	949.333
2013	8	20	10	1,015.366
2013	8	20	11	1,084.415
2013	8	20	12	1,144.685
2013	8	20	13	1,186.531
2013	8	20	14	1,221.096
2013	8	20	15	1,245.019
2013	8	20	16	1,266.842
2013	8	20	17	1,271.772
2013	8	20	18	1,252.037
2013	8	20	19	1,215.192
2013	8	20	20	1,156.067
2013	8	20	21	1,149.050
2013	8	20	22	1,102.083
2013	8	20	23	1,002.008
2013	8	20	24	910.433
2013	8	21	1	840.485
2013	8	21	2	787.409
2013	8	21	3	764.843
2013	8	21	4	742.567
2013	8	21	5	747.328
2013	8	21	6	790.176
2013	8	21	7	839.522
2013	8	21	8	906.454
2013	8	21	9	985.280
2013	8	21	10	1,053.391
2013	8	21	11	1,129.442
2013	8	21	12	1,191.945
2013	8	21	13	1,243.428
2013	8	21	14	1,293.791
2013	8	21	15	1,320.179
2013	8	21	16	1,339.780
2013	8	21	17	1,347.218
2013	8	21	18	1,323.403
2013	8	21	19	1,285.579
2013	8	21	20	1,228.273
2013	8	21	21	1,220.306
2013	8	21	22	1,166.559
2013	8	21	23	1,056.098
2013	8	21	24	961.817
2013	8	22	1	876.843
2013	8	22	2	831.529
2013	8	22	3	796.055
2013	8	22	4	780.188
2013	8	22	5	779.909
2013	8	22	6	826.730
2013	8	22	7	887.351
2013	8	22	8	942.585
2013	8	22	9	1,035.252

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	22	10	1,122.542
2013	8	22	11	1,204.130
2013	8	22	12	1,283.204
2013	8	22	13	1,319.945
2013	8	22	14	1,356.240
2013	8	22	15	1,332.715
2013	8	22	16	1,274.314
2013	8	22	17	1,253.911
2013	8	22	18	1,244.344
2013	8	22	19	1,206.358
2013	8	22	20	1,159.394
2013	8	22	21	1,161.769
2013	8	22	22	1,103.296
2013	8	22	23	1,004.803
2013	8	22	24	907.994
2013	8	23	1	834.317
2013	8	23	2	783.953
2013	8	23	3	746.829
2013	8	23	4	731.584
2013	8	23	5	731.744
2013	8	23	6	763.375
2013	8	23	7	819.973
2013	8	23	8	867.162
2013	8	23	9	942.467
2013	8	23	10	997.409
2013	8	23	11	1,035.954
2013	8	23	12	1,064.158
2013	8	23	13	1,072.769
2013	8	23	14	1,091.236
2013	8	23	15	1,089.503
2013	8	23	16	1,082.996
2013	8	23	17	1,069.616
2013	8	23	18	1,036.642
2013	8	23	19	995.308
2013	8	23	20	950.836
2013	8	23	21	952.726
2013	8	23	22	915.866
2013	8	23	23	847.407
2013	8	23	24	771.031
2013	8	24	1	717.346
2013	8	24	2	678.466
2013	8	24	3	655.670
2013	8	24	4	640.731
2013	8	24	5	635.251
2013	8	24	6	651.546
2013	8	24	7	662.937
2013	8	24	8	691.164
2013	8	24	9	750.572
2013	8	24	10	809.005
2013	8	24	11	852.675

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	24	12	874.520
2013	8	24	13	886.307
2013	8	24	14	894.626
2013	8	24	15	903.025
2013	8	24	16	915.702
2013	8	24	17	921.269
2013	8	24	18	928.633
2013	8	24	19	905.375
2013	8	24	20	867.849
2013	8	24	21	889.799
2013	8	24	22	857.171
2013	8	24	23	798.007
2013	8	24	24	738.037
2013	8	25	1	683.600
2013	8	25	2	654.126
2013	8	25	3	631.759
2013	8	25	4	616.911
2013	8	25	5	612.519
2013	8	25	6	615.619
2013	8	25	7	616.408
2013	8	25	8	636.877
2013	8	25	9	691.193
2013	8	25	10	752.914
2013	8	25	11	797.325
2013	8	25	12	849.047
2013	8	25	13	889.504
2013	8	25	14	919.072
2013	8	25	15	944.543
2013	8	25	16	964.337
2013	8	25	17	990.149
2013	8	25	18	984.609
2013	8	25	19	962.698
2013	8	25	20	951.813
2013	8	25	21	980.186
2013	8	25	22	952.618
2013	8	25	23	896.023
2013	8	25	24	820.413
2013	8	26	1	765.591
2013	8	26	2	727.194
2013	8	26	3	710.790
2013	8	26	4	704.116
2013	8	26	5	717.233
2013	8	26	6	774.837
2013	8	26	7	852.289
2013	8	26	8	923.443
2013	8	26	9	991.903
2013	8	26	10	1,034.103
2013	8	26	11	1,059.975
2013	8	26	12	1,094.925
2013	8	26	13	1,127.803

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	26	14	1,159.423
2013	8	26	15	1,164.344
2013	8	26	16	1,136.358
2013	8	26	17	1,103.060
2013	8	26	18	1,090.425
2013	8	26	19	1,075.951
2013	8	26	20	1,078.607
2013	8	26	21	1,082.162
2013	8	26	22	1,036.296
2013	8	26	23	957.506
2013	8	26	24	879.675
2013	8	27	1	820.682
2013	8	27	2	780.269
2013	8	27	3	757.428
2013	8	27	4	743.235
2013	8	27	5	756.425
2013	8	27	6	812.581
2013	8	27	7	883.290
2013	8	27	8	946.192
2013	8	27	9	1,013.792
2013	8	27	10	1,066.691
2013	8	27	11	1,106.062
2013	8	27	12	1,158.794
2013	8	27	13	1,210.822
2013	8	27	14	1,252.240
2013	8	27	15	1,256.186
2013	8	27	16	1,276.894
2013	8	27	17	1,278.900
2013	8	27	18	1,250.862
2013	8	27	19	1,221.520
2013	8	27	20	1,186.153
2013	8	27	21	1,199.769
2013	8	27	22	1,136.693
2013	8	27	23	1,043.896
2013	8	27	24	954.402
2013	8	28	1	883.008
2013	8	28	2	838.878
2013	8	28	3	806.803
2013	8	28	4	800.510
2013	8	28	5	797.409
2013	8	28	6	844.277
2013	8	28	7	915.825
2013	8	28	8	983.985
2013	8	28	9	1,054.657
2013	8	28	10	1,120.953
2013	8	28	11	1,172.474
2013	8	28	12	1,229.096
2013	8	28	13	1,277.090
2013	8	28	14	1,317.916
2013	8	28	15	1,337.969

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	28	16	1,353.464
2013	8	28	17	1,345.763
2013	8	28	18	1,327.766
2013	8	28	19	1,275.842
2013	8	28	20	1,225.180
2013	8	28	21	1,220.610
2013	8	28	22	1,161.484
2013	8	28	23	1,051.037
2013	8	28	24	954.541
2013	8	29	1	878.501
2013	8	29	2	825.495
2013	8	29	3	796.659
2013	8	29	4	768.215
2013	8	29	5	774.582
2013	8	29	6	824.603
2013	8	29	7	896.805
2013	8	29	8	963.829
2013	8	29	9	1,040.824
2013	8	29	10	1,105.703
2013	8	29	11	1,184.067
2013	8	29	12	1,248.670
2013	8	29	13	1,292.907
2013	8	29	14	1,336.146
2013	8	29	15	1,355.247
2013	8	29	16	1,361.534
2013	8	29	17	1,358.090
2013	8	29	18	1,332.733
2013	8	29	19	1,272.816
2013	8	29	20	1,206.271
2013	8	29	21	1,193.127
2013	8	29	22	1,131.346
2013	8	29	23	1,022.807
2013	8	29	24	927.802
2013	8	30	1	857.241
2013	8	30	2	800.522
2013	8	30	3	774.289
2013	8	30	4	751.669
2013	8	30	5	757.326
2013	8	30	6	797.536
2013	8	30	7	862.513
2013	8	30	8	915.211
2013	8	30	9	999.096
2013	8	30	10	1,081.039
2013	8	30	11	1,163.434
2013	8	30	12	1,227.616
2013	8	30	13	1,273.884
2013	8	30	14	1,298.629
2013	8	30	15	1,285.419
2013	8	30	16	1,273.300
2013	8	30	17	1,292.127

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	8	30	18	1,272.430
2013	8	30	19	1,230.760
2013	8	30	20	1,185.844
2013	8	30	21	1,189.910
2013	8	30	22	1,134.890
2013	8	30	23	1,043.154
2013	8	30	24	960.180
2013	8	31	1	889.114
2013	8	31	2	832.453
2013	8	31	3	797.572
2013	8	31	4	783.248
2013	8	31	5	774.475
2013	8	31	6	792.977
2013	8	31	7	821.683
2013	8	31	8	848.127
2013	8	31	9	906.889
2013	8	31	10	983.521
2013	8	31	11	1,055.582
2013	8	31	12	1,097.691
2013	8	31	13	1,114.218
2013	8	31	14	1,145.397
2013	8	31	15	1,151.122
2013	8	31	16	1,138.842
2013	8	31	17	1,113.069
2013	8	31	18	1,077.502
2013	8	31	19	1,042.243
2013	8	31	20	1,026.846
2013	8	31	21	1,046.219
2013	8	31	22	1,004.192
2013	8	31	23	939.239
2013	8	31	24	878.234
2013	9	1	1	809.878
2013	9	1	2	771.919
2013	9	1	3	731.434
2013	9	1	4	720.060
2013	9	1	5	713.045
2013	9	1	6	718.155
2013	9	1	7	733.783
2013	9	1	8	745.441
2013	9	1	9	802.958
2013	9	1	10	870.251
2013	9	1	11	922.810
2013	9	1	12	964.377
2013	9	1	13	1,004.312
2013	9	1	14	1,040.282
2013	9	1	15	1,052.405
2013	9	1	16	1,069.650
2013	9	1	17	1,091.464
2013	9	1	18	1,078.609
2013	9	1	19	1,042.760

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	1	20	1,029.075
2013	9	1	21	1,040.163
2013	9	1	22	1,003.834
2013	9	1	23	943.374
2013	9	1	24	872.540
2013	9	2	1	815.296
2013	9	2	2	772.347
2013	9	2	3	745.813
2013	9	2	4	727.438
2013	9	2	5	730.847
2013	9	2	6	740.163
2013	9	2	7	755.637
2013	9	2	8	760.095
2013	9	2	9	827.545
2013	9	2	10	926.513
2013	9	2	11	1,004.152
2013	9	2	12	1,066.550
2013	9	2	13	1,125.086
2013	9	2	14	1,157.679
2013	9	2	15	1,138.419
2013	9	2	16	1,156.642
2013	9	2	17	1,142.214
2013	9	2	18	1,108.314
2013	9	2	19	1,065.106
2013	9	2	20	1,038.035
2013	9	2	21	1,033.028
2013	9	2	22	968.462
2013	9	2	23	874.478
2013	9	2	24	797.895
2013	9	3	1	740.477
2013	9	3	2	706.356
2013	9	3	3	681.720
2013	9	3	4	673.714
2013	9	3	5	686.340
2013	9	3	6	733.042
2013	9	3	7	811.147
2013	9	3	8	866.562
2013	9	3	9	917.348
2013	9	3	10	955.279
2013	9	3	11	995.051
2013	9	3	12	1,005.773
2013	9	3	13	1,008.709
2013	9	3	14	1,008.357
2013	9	3	15	994.959
2013	9	3	16	985.003
2013	9	3	17	968.437
2013	9	3	18	959.759
2013	9	3	19	971.339
2013	9	3	20	977.136
2013	9	3	21	986.188

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	3	22	925.762
2013	9	3	23	843.645
2013	9	3	24	773.869
2013	9	4	1	719.788
2013	9	4	2	689.022
2013	9	4	3	669.691
2013	9	4	4	656.229
2013	9	4	5	667.271
2013	9	4	6	716.234
2013	9	4	7	799.681
2013	9	4	8	846.187
2013	9	4	9	897.969
2013	9	4	10	951.210
2013	9	4	11	991.643
2013	9	4	12	1,017.009
2013	9	4	13	1,030.730
2013	9	4	14	1,056.017
2013	9	4	15	1,069.995
2013	9	4	16	1,079.801
2013	9	4	17	1,073.735
2013	9	4	18	1,062.037
2013	9	4	19	1,027.673
2013	9	4	20	1,028.851
2013	9	4	21	1,048.477
2013	9	4	22	984.928
2013	9	4	23	902.298
2013	9	4	24	822.524
2013	9	5	1	759.302
2013	9	5	2	718.773
2013	9	5	3	685.602
2013	9	5	4	676.499
2013	9	5	5	683.045
2013	9	5	6	724.263
2013	9	5	7	806.529
2013	9	5	8	850.853
2013	9	5	9	890.201
2013	9	5	10	929.136
2013	9	5	11	962.138
2013	9	5	12	974.386
2013	9	5	13	977.557
2013	9	5	14	983.637
2013	9	5	15	975.091
2013	9	5	16	965.016
2013	9	5	17	956.244
2013	9	5	18	932.691
2013	9	5	19	911.477
2013	9	5	20	907.667
2013	9	5	21	925.662
2013	9	5	22	877.305
2013	9	5	23	800.223

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	5	24	726.784
2013	9	6	1	678.872
2013	9	6	2	651.392
2013	9	6	3	634.935
2013	9	6	4	625.049
2013	9	6	5	635.176
2013	9	6	6	681.224
2013	9	6	7	757.683
2013	9	6	8	802.292
2013	9	6	9	844.737
2013	9	6	10	873.371
2013	9	6	11	910.775
2013	9	6	12	920.465
2013	9	6	13	924.654
2013	9	6	14	937.645
2013	9	6	15	940.672
2013	9	6	16	935.900
2013	9	6	17	922.240
2013	9	6	18	902.895
2013	9	6	19	874.069
2013	9	6	20	876.279
2013	9	6	21	896.411
2013	9	6	22	851.793
2013	9	6	23	786.805
2013	9	6	24	719.586
2013	9	7	1	672.895
2013	9	7	2	641.297
2013	9	7	3	623.418
2013	9	7	4	609.936
2013	9	7	5	610.434
2013	9	7	6	626.702
2013	9	7	7	643.556
2013	9	7	8	673.345
2013	9	7	9	721.982
2013	9	7	10	763.409
2013	9	7	11	792.302
2013	9	7	12	800.035
2013	9	7	13	806.600
2013	9	7	14	806.855
2013	9	7	15	799.831
2013	9	7	16	800.318
2013	9	7	17	804.129
2013	9	7	18	815.452
2013	9	7	19	817.904
2013	9	7	20	841.142
2013	9	7	21	852.716
2013	9	7	22	815.143
2013	9	7	23	764.210
2013	9	7	24	710.267
2013	9	8	1	666.083

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	8	2	637.283
2013	9	8	3	622.476
2013	9	8	4	616.241
2013	9	8	5	616.108
2013	9	8	6	629.637
2013	9	8	7	639.377
2013	9	8	8	652.994
2013	9	8	9	685.094
2013	9	8	10	723.192
2013	9	8	11	756.116
2013	9	8	12	769.217
2013	9	8	13	787.860
2013	9	8	14	785.102
2013	9	8	15	791.979
2013	9	8	16	793.263
2013	9	8	17	802.333
2013	9	8	18	812.543
2013	9	8	19	805.052
2013	9	8	20	820.300
2013	9	8	21	845.839
2013	9	8	22	795.944
2013	9	8	23	735.366
2013	9	8	24	682.386
2013	9	9	1	638.132
2013	9	9	2	615.820
2013	9	9	3	605.712
2013	9	9	4	602.238
2013	9	9	5	618.608
2013	9	9	6	667.634
2013	9	9	7	763.498
2013	9	9	8	808.642
2013	9	9	9	845.768
2013	9	9	10	875.397
2013	9	9	11	903.968
2013	9	9	12	928.586
2013	9	9	13	945.717
2013	9	9	14	962.633
2013	9	9	15	979.630
2013	9	9	16	981.747
2013	9	9	17	972.556
2013	9	9	18	961.758
2013	9	9	19	948.230
2013	9	9	20	969.655
2013	9	9	21	984.313
2013	9	9	22	936.927
2013	9	9	23	849.447
2013	9	9	24	786.606
2013	9	10	1	726.874
2013	9	10	2	707.447
2013	9	10	3	686.673

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	10	4	683.032
2013	9	10	5	703.359
2013	9	10	6	762.736
2013	9	10	7	875.534
2013	9	10	8	951.086
2013	9	10	9	1,007.931
2013	9	10	10	1,042.517
2013	9	10	11	1,108.516
2013	9	10	12	1,180.712
2013	9	10	13	1,254.959
2013	9	10	14	1,324.754
2013	9	10	15	1,374.972
2013	9	10	16	1,414.405
2013	9	10	17	1,440.965
2013	9	10	18	1,431.615
2013	9	10	19	1,399.874
2013	9	10	20	1,384.224
2013	9	10	21	1,397.058
2013	9	10	22	1,310.023
2013	9	10	23	1,200.079
2013	9	10	24	1,101.834
2013	9	11	1	1,022.993
2013	9	11	2	964.207
2013	9	11	3	921.926
2013	9	11	4	908.683
2013	9	11	5	908.682
2013	9	11	6	974.762
2013	9	11	7	1,075.848
2013	9	11	8	1,139.318
2013	9	11	9	1,218.590
2013	9	11	10	1,297.532
2013	9	11	11	1,384.873
2013	9	11	12	1,449.506
2013	9	11	13	1,498.905
2013	9	11	14	1,528.214
2013	9	11	15	1,545.245
2013	9	11	16	1,557.972
2013	9	11	17	1,522.537
2013	9	11	18	1,507.489
2013	9	11	19	1,435.868
2013	9	11	20	1,404.082
2013	9	11	21	1,390.307
2013	9	11	22	1,279.203
2013	9	11	23	1,152.851
2013	9	11	24	1,041.583
2013	9	12	1	954.579
2013	9	12	2	906.180
2013	9	12	3	856.980
2013	9	12	4	843.413
2013	9	12	5	838.373

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	12	6	890.684
2013	9	12	7	994.778
2013	9	12	8	1,035.356
2013	9	12	9	1,080.529
2013	9	12	10	1,103.633
2013	9	12	11	1,128.577
2013	9	12	12	1,130.407
2013	9	12	13	1,129.851
2013	9	12	14	1,122.108
2013	9	12	15	1,100.352
2013	9	12	16	1,090.214
2013	9	12	17	1,082.208
2013	9	12	18	1,067.715
2013	9	12	19	1,050.323
2013	9	12	20	1,034.828
2013	9	12	21	1,030.832
2013	9	12	22	971.689
2013	9	12	23	877.815
2013	9	12	24	802.012
2013	9	13	1	741.268
2013	9	13	2	706.727
2013	9	13	3	680.013
2013	9	13	4	678.024
2013	9	13	5	677.719
2013	9	13	6	725.892
2013	9	13	7	806.914
2013	9	13	8	855.657
2013	9	13	9	885.047
2013	9	13	10	900.543
2013	9	13	11	914.390
2013	9	13	12	913.585
2013	9	13	13	905.480
2013	9	13	14	900.589
2013	9	13	15	890.150
2013	9	13	16	882.221
2013	9	13	17	871.074
2013	9	13	18	858.713
2013	9	13	19	862.150
2013	9	13	20	866.973
2013	9	13	21	861.765
2013	9	13	22	824.121
2013	9	13	23	759.795
2013	9	13	24	704.593
2013	9	14	1	647.951
2013	9	14	2	623.126
2013	9	14	3	604.055
2013	9	14	4	597.030
2013	9	14	5	596.275
2013	9	14	6	611.520
2013	9	14	7	646.195

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	14	8	677.477
2013	9	14	9	718.872
2013	9	14	10	758.153
2013	9	14	11	780.682
2013	9	14	12	783.448
2013	9	14	13	772.146
2013	9	14	14	770.895
2013	9	14	15	766.187
2013	9	14	16	757.463
2013	9	14	17	763.834
2013	9	14	18	763.990
2013	9	14	19	764.256
2013	9	14	20	786.881
2013	9	14	21	805.714
2013	9	14	22	773.914
2013	9	14	23	725.219
2013	9	14	24	665.326
2013	9	15	1	629.733
2013	9	15	2	599.817
2013	9	15	3	581.543
2013	9	15	4	573.210
2013	9	15	5	569.545
2013	9	15	6	579.639
2013	9	15	7	596.542
2013	9	15	8	615.808
2013	9	15	9	652.625
2013	9	15	10	689.707
2013	9	15	11	716.921
2013	9	15	12	739.899
2013	9	15	13	750.040
2013	9	15	14	765.442
2013	9	15	15	759.639
2013	9	15	16	764.588
2013	9	15	17	771.542
2013	9	15	18	792.387
2013	9	15	19	798.396
2013	9	15	20	837.614
2013	9	15	21	841.025
2013	9	15	22	787.110
2013	9	15	23	729.404
2013	9	15	24	669.378
2013	9	16	1	630.571
2013	9	16	2	611.965
2013	9	16	3	601.180
2013	9	16	4	595.620
2013	9	16	5	609.720
2013	9	16	6	663.634
2013	9	16	7	758.554
2013	9	16	8	809.937
2013	9	16	9	854.234

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	16	10	887.519
2013	9	16	11	910.014
2013	9	16	12	912.299
2013	9	16	13	907.792
2013	9	16	14	905.084
2013	9	16	15	901.831
2013	9	16	16	888.825
2013	9	16	17	887.018
2013	9	16	18	884.802
2013	9	16	19	870.858
2013	9	16	20	906.004
2013	9	16	21	916.093
2013	9	16	22	856.264
2013	9	16	23	779.684
2013	9	16	24	710.446
2013	9	17	1	665.231
2013	9	17	2	638.763
2013	9	17	3	621.253
2013	9	17	4	620.505
2013	9	17	5	635.285
2013	9	17	6	690.038
2013	9	17	7	783.365
2013	9	17	8	830.013
2013	9	17	9	858.244
2013	9	17	10	873.516
2013	9	17	11	886.491
2013	9	17	12	899.223
2013	9	17	13	892.316
2013	9	17	14	899.309
2013	9	17	15	899.451
2013	9	17	16	893.771
2013	9	17	17	884.083
2013	9	17	18	877.816
2013	9	17	19	868.350
2013	9	17	20	900.278
2013	9	17	21	906.083
2013	9	17	22	851.790
2013	9	17	23	773.863
2013	9	17	24	703.622
2013	9	18	1	657.503
2013	9	18	2	639.105
2013	9	18	3	617.824
2013	9	18	4	615.211
2013	9	18	5	625.725
2013	9	18	6	684.838
2013	9	18	7	776.243
2013	9	18	8	820.657
2013	9	18	9	849.633
2013	9	18	10	873.377
2013	9	18	11	897.888

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	18	12	911.409
2013	9	18	13	918.571
2013	9	18	14	935.042
2013	9	18	15	941.013
2013	9	18	16	937.204
2013	9	18	17	926.666
2013	9	18	18	913.927
2013	9	18	19	900.647
2013	9	18	20	931.018
2013	9	18	21	924.908
2013	9	18	22	865.888
2013	9	18	23	781.092
2013	9	18	24	718.085
2013	9	19	1	668.312
2013	9	19	2	638.859
2013	9	19	3	621.740
2013	9	19	4	617.013
2013	9	19	5	631.597
2013	9	19	6	680.076
2013	9	19	7	775.770
2013	9	19	8	818.168
2013	9	19	9	857.242
2013	9	19	10	885.496
2013	9	19	11	929.425
2013	9	19	12	954.512
2013	9	19	13	965.254
2013	9	19	14	984.919
2013	9	19	15	991.220
2013	9	19	16	995.279
2013	9	19	17	990.130
2013	9	19	18	973.945
2013	9	19	19	956.700
2013	9	19	20	983.864
2013	9	19	21	973.575
2013	9	19	22	915.807
2013	9	19	23	825.636
2013	9	19	24	757.177
2013	9	20	1	698.693
2013	9	20	2	670.726
2013	9	20	3	646.405
2013	9	20	4	638.496
2013	9	20	5	645.813
2013	9	20	6	698.589
2013	9	20	7	792.592
2013	9	20	8	830.650
2013	9	20	9	880.697
2013	9	20	10	921.043
2013	9	20	11	973.379
2013	9	20	12	1,004.644
2013	9	20	13	1,022.830

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	20	14	1,056.277
2013	9	20	15	1,068.193
2013	9	20	16	1,079.509
2013	9	20	17	1,070.765
2013	9	20	18	1,039.756
2013	9	20	19	1,008.439
2013	9	20	20	1,025.445
2013	9	20	21	1,014.205
2013	9	20	22	959.138
2013	9	20	23	885.714
2013	9	20	24	812.969
2013	9	21	1	752.381
2013	9	21	2	712.960
2013	9	21	3	685.749
2013	9	21	4	673.269
2013	9	21	5	666.405
2013	9	21	6	676.838
2013	9	21	7	711.651
2013	9	21	8	743.475
2013	9	21	9	795.431
2013	9	21	10	844.870
2013	9	21	11	865.862
2013	9	21	12	876.461
2013	9	21	13	872.905
2013	9	21	14	853.707
2013	9	21	15	847.201
2013	9	21	16	836.537
2013	9	21	17	830.638
2013	9	21	18	836.155
2013	9	21	19	845.370
2013	9	21	20	867.365
2013	9	21	21	852.064
2013	9	21	22	811.676
2013	9	21	23	750.900
2013	9	21	24	691.113
2013	9	22	1	645.753
2013	9	22	2	613.486
2013	9	22	3	592.470
2013	9	22	4	584.752
2013	9	22	5	577.865
2013	9	22	6	588.457
2013	9	22	7	607.198
2013	9	22	8	615.576
2013	9	22	9	665.016
2013	9	22	10	703.349
2013	9	22	11	724.235
2013	9	22	12	741.271
2013	9	22	13	750.496
2013	9	22	14	747.871
2013	9	22	15	749.606

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	22	16	746.675
2013	9	22	17	761.423
2013	9	22	18	776.899
2013	9	22	19	788.040
2013	9	22	20	826.180
2013	9	22	21	820.913
2013	9	22	22	776.087
2013	9	22	23	715.992
2013	9	22	24	662.586
2013	9	23	1	624.956
2013	9	23	2	606.034
2013	9	23	3	589.733
2013	9	23	4	589.703
2013	9	23	5	600.314
2013	9	23	6	658.380
2013	9	23	7	768.260
2013	9	23	8	814.127
2013	9	23	9	840.691
2013	9	23	10	862.884
2013	9	23	11	880.349
2013	9	23	12	885.475
2013	9	23	13	882.441
2013	9	23	14	888.842
2013	9	23	15	883.927
2013	9	23	16	874.406
2013	9	23	17	872.287
2013	9	23	18	863.100
2013	9	23	19	860.745
2013	9	23	20	908.480
2013	9	23	21	903.644
2013	9	23	22	847.729
2013	9	23	23	771.062
2013	9	23	24	702.313
2013	9	24	1	657.482
2013	9	24	2	630.409
2013	9	24	3	614.761
2013	9	24	4	611.116
2013	9	24	5	624.958
2013	9	24	6	676.526
2013	9	24	7	778.076
2013	9	24	8	823.736
2013	9	24	9	855.669
2013	9	24	10	870.200
2013	9	24	11	892.464
2013	9	24	12	896.625
2013	9	24	13	898.816
2013	9	24	14	907.967
2013	9	24	15	899.282
2013	9	24	16	898.232
2013	9	24	17	882.940

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	24	18	876.653
2013	9	24	19	870.905
2013	9	24	20	907.784
2013	9	24	21	900.886
2013	9	24	22	845.040
2013	9	24	23	767.453
2013	9	24	24	705.857
2013	9	25	1	655.996
2013	9	25	2	631.235
2013	9	25	3	618.376
2013	9	25	4	618.671
2013	9	25	5	625.326
2013	9	25	6	681.003
2013	9	25	7	779.455
2013	9	25	8	816.772
2013	9	25	9	846.596
2013	9	25	10	866.793
2013	9	25	11	898.377
2013	9	25	12	907.100
2013	9	25	13	910.930
2013	9	25	14	924.941
2013	9	25	15	918.530
2013	9	25	16	908.686
2013	9	25	17	903.276
2013	9	25	18	883.180
2013	9	25	19	874.088
2013	9	25	20	919.043
2013	9	25	21	904.282
2013	9	25	22	847.206
2013	9	25	23	767.425
2013	9	25	24	701.722
2013	9	26	1	656.525
2013	9	26	2	631.126
2013	9	26	3	612.793
2013	9	26	4	612.048
2013	9	26	5	622.504
2013	9	26	6	674.161
2013	9	26	7	773.799
2013	9	26	8	817.715
2013	9	26	9	844.334
2013	9	26	10	870.543
2013	9	26	11	898.784
2013	9	26	12	917.486
2013	9	26	13	925.381
2013	9	26	14	927.505
2013	9	26	15	929.542
2013	9	26	16	924.894
2013	9	26	17	915.180
2013	9	26	18	898.589
2013	9	26	19	886.933

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	26	20	926.808
2013	9	26	21	915.132
2013	9	26	22	859.180
2013	9	26	23	773.559
2013	9	26	24	711.174
2013	9	27	1	660.256
2013	9	27	2	634.759
2013	9	27	3	613.394
2013	9	27	4	607.411
2013	9	27	5	616.295
2013	9	27	6	665.838
2013	9	27	7	761.183
2013	9	27	8	810.196
2013	9	27	9	841.371
2013	9	27	10	863.437
2013	9	27	11	883.361
2013	9	27	12	892.427
2013	9	27	13	899.780
2013	9	27	14	904.384
2013	9	27	15	898.300
2013	9	27	16	892.435
2013	9	27	17	870.392
2013	9	27	18	854.340
2013	9	27	19	838.251
2013	9	27	20	872.208
2013	9	27	21	857.189
2013	9	27	22	815.624
2013	9	27	23	749.589
2013	9	27	24	683.988
2013	9	28	1	636.223
2013	9	28	2	610.125
2013	9	28	3	594.163
2013	9	28	4	583.835
2013	9	28	5	584.975
2013	9	28	6	601.296
2013	9	28	7	634.837
2013	9	28	8	656.179
2013	9	28	9	708.035
2013	9	28	10	738.476
2013	9	28	11	765.412
2013	9	28	12	776.773
2013	9	28	13	780.525
2013	9	28	14	780.645
2013	9	28	15	786.022
2013	9	28	16	789.017
2013	9	28	17	792.948
2013	9	28	18	802.472
2013	9	28	19	796.570
2013	9	28	20	832.232
2013	9	28	21	829.678

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	28	22	786.735
2013	9	28	23	730.030
2013	9	28	24	670.478
2013	9	29	1	622.388
2013	9	29	2	595.401
2013	9	29	3	577.662
2013	9	29	4	569.579
2013	9	29	5	564.110
2013	9	29	6	572.296
2013	9	29	7	595.819
2013	9	29	8	606.944
2013	9	29	9	656.753
2013	9	29	10	693.433
2013	9	29	11	726.098
2013	9	29	12	744.624
2013	9	29	13	761.609
2013	9	29	14	780.234
2013	9	29	15	784.663
2013	9	29	16	793.314
2013	9	29	17	798.128
2013	9	29	18	812.746
2013	9	29	19	813.238
2013	9	29	20	864.885
2013	9	29	21	844.407
2013	9	29	22	797.671
2013	9	29	23	733.430
2013	9	29	24	673.392
2013	9	30	1	635.197
2013	9	30	2	608.722
2013	9	30	3	596.411
2013	9	30	4	595.734
2013	9	30	5	604.030
2013	9	30	6	665.635
2013	9	30	7	767.748
2013	9	30	8	822.758
2013	9	30	9	864.607
2013	9	30	10	890.858
2013	9	30	11	919.741
2013	9	30	12	926.561
2013	9	30	13	947.192
2013	9	30	14	961.006
2013	9	30	15	974.481
2013	9	30	16	971.831
2013	9	30	17	967.461
2013	9	30	18	948.507
2013	9	30	19	950.458
2013	9	30	20	994.398
2013	9	30	21	965.211
2013	9	30	22	899.828
2013	9	30	23	821.054

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	9	30	24	757.754
2013	10	1	1	708.884
2013	10	1	2	673.568
2013	10	1	3	662.901
2013	10	1	4	651.378
2013	10	1	5	665.558
2013	10	1	6	720.379
2013	10	1	7	812.214
2013	10	1	8	862.704
2013	10	1	9	897.392
2013	10	1	10	931.349
2013	10	1	11	957.037
2013	10	1	12	974.126
2013	10	1	13	988.032
2013	10	1	14	996.829
2013	10	1	15	1,003.768
2013	10	1	16	1,001.646
2013	10	1	17	993.407
2013	10	1	18	974.331
2013	10	1	19	956.660
2013	10	1	20	994.291
2013	10	1	21	972.302
2013	10	1	22	907.191
2013	10	1	23	825.007
2013	10	1	24	752.525
2013	10	2	1	704.250
2013	10	2	2	673.601
2013	10	2	3	656.546
2013	10	2	4	654.752
2013	10	2	5	664.797
2013	10	2	6	723.238
2013	10	2	7	825.744
2013	10	2	8	887.012
2013	10	2	9	920.101
2013	10	2	10	950.970
2013	10	2	11	975.785
2013	10	2	12	996.522
2013	10	2	13	1,003.558
2013	10	2	14	1,013.314
2013	10	2	15	1,022.730
2013	10	2	16	1,022.475
2013	10	2	17	1,005.992
2013	10	2	18	976.240
2013	10	2	19	958.228
2013	10	2	20	998.400
2013	10	2	21	979.159
2013	10	2	22	912.908
2013	10	2	23	828.118
2013	10	2	24	748.760
2013	10	3	1	694.368

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	3	2	658.268
2013	10	3	3	635.747
2013	10	3	4	626.677
2013	10	3	5	639.978
2013	10	3	6	683.752
2013	10	3	7	784.268
2013	10	3	8	827.844
2013	10	3	9	856.871
2013	10	3	10	889.576
2013	10	3	11	921.082
2013	10	3	12	937.759
2013	10	3	13	951.057
2013	10	3	14	960.597
2013	10	3	15	954.427
2013	10	3	16	943.529
2013	10	3	17	925.752
2013	10	3	18	915.581
2013	10	3	19	911.437
2013	10	3	20	956.292
2013	10	3	21	936.469
2013	10	3	22	883.059
2013	10	3	23	807.951
2013	10	3	24	737.012
2013	10	4	1	683.662
2013	10	4	2	657.551
2013	10	4	3	641.517
2013	10	4	4	633.550
2013	10	4	5	651.702
2013	10	4	6	692.538
2013	10	4	7	794.272
2013	10	4	8	868.134
2013	10	4	9	904.019
2013	10	4	10	927.577
2013	10	4	11	951.134
2013	10	4	12	964.199
2013	10	4	13	957.599
2013	10	4	14	949.899
2013	10	4	15	940.137
2013	10	4	16	923.567
2013	10	4	17	906.130
2013	10	4	18	893.458
2013	10	4	19	897.809
2013	10	4	20	921.532
2013	10	4	21	893.798
2013	10	4	22	850.724
2013	10	4	23	786.554
2013	10	4	24	724.636
2013	10	5	1	668.995
2013	10	5	2	643.803
2013	10	5	3	624.073

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	5	4	612.845
2013	10	5	5	615.233
2013	10	5	6	627.975
2013	10	5	7	663.041
2013	10	5	8	701.049
2013	10	5	9	741.593
2013	10	5	10	784.821
2013	10	5	11	809.327
2013	10	5	12	815.857
2013	10	5	13	808.101
2013	10	5	14	804.846
2013	10	5	15	792.524
2013	10	5	16	782.939
2013	10	5	17	781.763
2013	10	5	18	796.034
2013	10	5	19	824.347
2013	10	5	20	847.341
2013	10	5	21	830.536
2013	10	5	22	795.477
2013	10	5	23	746.482
2013	10	5	24	692.753
2013	10	6	1	648.556
2013	10	6	2	623.807
2013	10	6	3	603.482
2013	10	6	4	593.412
2013	10	6	5	594.350
2013	10	6	6	601.065
2013	10	6	7	624.786
2013	10	6	8	642.381
2013	10	6	9	685.447
2013	10	6	10	733.489
2013	10	6	11	768.722
2013	10	6	12	803.238
2013	10	6	13	823.423
2013	10	6	14	841.922
2013	10	6	15	856.546
2013	10	6	16	878.066
2013	10	6	17	907.293
2013	10	6	18	916.129
2013	10	6	19	935.486
2013	10	6	20	983.287
2013	10	6	21	958.154
2013	10	6	22	905.246
2013	10	6	23	843.927
2013	10	6	24	779.926
2013	10	7	1	732.154
2013	10	7	2	699.525
2013	10	7	3	681.639
2013	10	7	4	670.307
2013	10	7	5	690.111

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	7	6	745.146
2013	10	7	7	858.212
2013	10	7	8	917.508
2013	10	7	9	935.171
2013	10	7	10	943.415
2013	10	7	11	959.245
2013	10	7	12	955.054
2013	10	7	13	944.260
2013	10	7	14	932.463
2013	10	7	15	914.220
2013	10	7	16	910.112
2013	10	7	17	897.322
2013	10	7	18	888.425
2013	10	7	19	909.050
2013	10	7	20	941.051
2013	10	7	21	918.122
2013	10	7	22	855.135
2013	10	7	23	786.570
2013	10	7	24	714.976
2013	10	8	1	672.882
2013	10	8	2	637.745
2013	10	8	3	628.485
2013	10	8	4	619.993
2013	10	8	5	633.070
2013	10	8	6	683.353
2013	10	8	7	787.260
2013	10	8	8	834.773
2013	10	8	9	863.901
2013	10	8	10	878.812
2013	10	8	11	898.791
2013	10	8	12	905.261
2013	10	8	13	902.094
2013	10	8	14	911.778
2013	10	8	15	906.817
2013	10	8	16	904.522
2013	10	8	17	891.522
2013	10	8	18	877.761
2013	10	8	19	890.057
2013	10	8	20	933.661
2013	10	8	21	910.614
2013	10	8	22	852.289
2013	10	8	23	773.356
2013	10	8	24	712.170
2013	10	9	1	665.501
2013	10	9	2	636.746
2013	10	9	3	625.652
2013	10	9	4	616.612
2013	10	9	5	632.484
2013	10	9	6	684.323
2013	10	9	7	785.529

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	9	8	844.165
2013	10	9	9	861.807
2013	10	9	10	879.835
2013	10	9	11	894.253
2013	10	9	12	911.358
2013	10	9	13	913.296
2013	10	9	14	920.041
2013	10	9	15	920.357
2013	10	9	16	915.690
2013	10	9	17	900.295
2013	10	9	18	883.306
2013	10	9	19	901.660
2013	10	9	20	941.597
2013	10	9	21	914.237
2013	10	9	22	858.030
2013	10	9	23	774.129
2013	10	9	24	716.732
2013	10	10	1	662.694
2013	10	10	2	641.507
2013	10	10	3	621.786
2013	10	10	4	619.730
2013	10	10	5	630.604
2013	10	10	6	684.874
2013	10	10	7	787.442
2013	10	10	8	844.140
2013	10	10	9	861.783
2013	10	10	10	875.123
2013	10	10	11	897.944
2013	10	10	12	893.642
2013	10	10	13	897.308
2013	10	10	14	899.476
2013	10	10	15	902.945
2013	10	10	16	897.595
2013	10	10	17	887.967
2013	10	10	18	872.671
2013	10	10	19	894.202
2013	10	10	20	932.833
2013	10	10	21	907.110
2013	10	10	22	850.110
2013	10	10	23	777.479
2013	10	10	24	712.067
2013	10	11	1	665.018
2013	10	11	2	632.514
2013	10	11	3	620.955
2013	10	11	4	617.798
2013	10	11	5	625.833
2013	10	11	6	674.718
2013	10	11	7	765.667
2013	10	11	8	825.868
2013	10	11	9	847.176

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	11	10	870.441
2013	10	11	11	891.856
2013	10	11	12	898.418
2013	10	11	13	906.029
2013	10	11	14	906.451
2013	10	11	15	898.328
2013	10	11	16	888.612
2013	10	11	17	871.972
2013	10	11	18	850.796
2013	10	11	19	864.681
2013	10	11	20	887.802
2013	10	11	21	864.563
2013	10	11	22	823.383
2013	10	11	23	757.202
2013	10	11	24	694.774
2013	10	12	1	650.388
2013	10	12	2	623.061
2013	10	12	3	601.696
2013	10	12	4	597.081
2013	10	12	5	600.075
2013	10	12	6	612.542
2013	10	12	7	653.044
2013	10	12	8	682.807
2013	10	12	9	719.423
2013	10	12	10	754.075
2013	10	12	11	774.955
2013	10	12	12	779.203
2013	10	12	13	785.358
2013	10	12	14	780.403
2013	10	12	15	774.546
2013	10	12	16	775.213
2013	10	12	17	777.802
2013	10	12	18	782.044
2013	10	12	19	801.579
2013	10	12	20	830.009
2013	10	12	21	806.012
2013	10	12	22	771.203
2013	10	12	23	720.991
2013	10	12	24	668.937
2013	10	13	1	625.651
2013	10	13	2	598.791
2013	10	13	3	581.420
2013	10	13	4	570.839
2013	10	13	5	572.431
2013	10	13	6	587.146
2013	10	13	7	607.440
2013	10	13	8	622.150
2013	10	13	9	661.761
2013	10	13	10	697.116
2013	10	13	11	726.150

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	13	12	750.972
2013	10	13	13	768.827
2013	10	13	14	771.390
2013	10	13	15	768.200
2013	10	13	16	771.938
2013	10	13	17	781.057
2013	10	13	18	796.384
2013	10	13	19	833.322
2013	10	13	20	856.878
2013	10	13	21	828.510
2013	10	13	22	787.847
2013	10	13	23	737.807
2013	10	13	24	692.928
2013	10	14	1	650.329
2013	10	14	2	625.729
2013	10	14	3	614.942
2013	10	14	4	606.197
2013	10	14	5	620.095
2013	10	14	6	661.102
2013	10	14	7	730.973
2013	10	14	8	803.803
2013	10	14	9	834.251
2013	10	14	10	871.158
2013	10	14	11	898.549
2013	10	14	12	909.247
2013	10	14	13	911.618
2013	10	14	14	911.981
2013	10	14	15	904.063
2013	10	14	16	896.205
2013	10	14	17	888.807
2013	10	14	18	889.168
2013	10	14	19	919.866
2013	10	14	20	932.946
2013	10	14	21	906.874
2013	10	14	22	844.329
2013	10	14	23	776.037
2013	10	14	24	709.128
2013	10	15	1	659.363
2013	10	15	2	634.105
2013	10	15	3	618.066
2013	10	15	4	612.643
2013	10	15	5	629.605
2013	10	15	6	677.891
2013	10	15	7	778.687
2013	10	15	8	843.639
2013	10	15	9	858.295
2013	10	15	10	880.202
2013	10	15	11	892.826
2013	10	15	12	907.683
2013	10	15	13	916.027

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	15	14	919.760
2013	10	15	15	914.679
2013	10	15	16	907.547
2013	10	15	17	900.656
2013	10	15	18	889.707
2013	10	15	19	926.498
2013	10	15	20	954.948
2013	10	15	21	917.575
2013	10	15	22	867.012
2013	10	15	23	788.936
2013	10	15	24	726.364
2013	10	16	1	671.607
2013	10	16	2	653.271
2013	10	16	3	639.081
2013	10	16	4	630.616
2013	10	16	5	642.818
2013	10	16	6	689.856
2013	10	16	7	788.710
2013	10	16	8	867.056
2013	10	16	9	881.458
2013	10	16	10	901.090
2013	10	16	11	919.450
2013	10	16	12	926.689
2013	10	16	13	927.129
2013	10	16	14	924.820
2013	10	16	15	924.087
2013	10	16	16	917.081
2013	10	16	17	910.058
2013	10	16	18	908.088
2013	10	16	19	945.902
2013	10	16	20	960.625
2013	10	16	21	933.648
2013	10	16	22	875.046
2013	10	16	23	794.395
2013	10	16	24	725.311
2013	10	17	1	675.261
2013	10	17	2	648.152
2013	10	17	3	629.169
2013	10	17	4	622.776
2013	10	17	5	632.011
2013	10	17	6	686.460
2013	10	17	7	776.553
2013	10	17	8	846.266
2013	10	17	9	863.897
2013	10	17	10	877.153
2013	10	17	11	897.647
2013	10	17	12	909.448
2013	10	17	13	900.343
2013	10	17	14	905.228
2013	10	17	15	897.851

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	17	16	896.214
2013	10	17	17	881.679
2013	10	17	18	882.903
2013	10	17	19	934.532
2013	10	17	20	944.639
2013	10	17	21	916.740
2013	10	17	22	859.982
2013	10	17	23	785.987
2013	10	17	24	723.957
2013	10	18	1	672.806
2013	10	18	2	640.112
2013	10	18	3	627.905
2013	10	18	4	618.669
2013	10	18	5	632.251
2013	10	18	6	681.829
2013	10	18	7	774.284
2013	10	18	8	836.075
2013	10	18	9	847.858
2013	10	18	10	861.989
2013	10	18	11	878.391
2013	10	18	12	881.875
2013	10	18	13	876.647
2013	10	18	14	878.377
2013	10	18	15	864.440
2013	10	18	16	852.396
2013	10	18	17	841.823
2013	10	18	18	832.788
2013	10	18	19	866.475
2013	10	18	20	879.913
2013	10	18	21	856.415
2013	10	18	22	819.063
2013	10	18	23	756.729
2013	10	18	24	693.235
2013	10	19	1	646.144
2013	10	19	2	615.624
2013	10	19	3	603.512
2013	10	19	4	591.286
2013	10	19	5	592.872
2013	10	19	6	609.034
2013	10	19	7	647.775
2013	10	19	8	684.814
2013	10	19	9	712.758
2013	10	19	10	747.391
2013	10	19	11	769.067
2013	10	19	12	778.159
2013	10	19	13	771.692
2013	10	19	14	762.196
2013	10	19	15	756.631
2013	10	19	16	751.349
2013	10	19	17	756.298

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	19	18	779.395
2013	10	19	19	825.768
2013	10	19	20	829.936
2013	10	19	21	808.699
2013	10	19	22	773.701
2013	10	19	23	723.116
2013	10	19	24	675.368
2013	10	20	1	631.155
2013	10	20	2	605.376
2013	10	20	3	588.363
2013	10	20	4	578.414
2013	10	20	5	579.060
2013	10	20	6	587.865
2013	10	20	7	615.824
2013	10	20	8	640.733
2013	10	20	9	669.660
2013	10	20	10	706.730
2013	10	20	11	718.679
2013	10	20	12	733.922
2013	10	20	13	742.664
2013	10	20	14	746.753
2013	10	20	15	752.858
2013	10	20	16	752.664
2013	10	20	17	773.624
2013	10	20	18	814.152
2013	10	20	19	854.805
2013	10	20	20	855.579
2013	10	20	21	828.745
2013	10	20	22	779.963
2013	10	20	23	725.340
2013	10	20	24	673.514
2013	10	21	1	637.390
2013	10	21	2	613.302
2013	10	21	3	602.119
2013	10	21	4	600.049
2013	10	21	5	618.417
2013	10	21	6	678.767
2013	10	21	7	781.658
2013	10	21	8	850.957
2013	10	21	9	870.947
2013	10	21	10	876.814
2013	10	21	11	896.574
2013	10	21	12	895.802
2013	10	21	13	896.761
2013	10	21	14	894.981
2013	10	21	15	887.907
2013	10	21	16	875.692
2013	10	21	17	874.211
2013	10	21	18	876.130
2013	10	21	19	930.722

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	21	20	944.064
2013	10	21	21	913.545
2013	10	21	22	854.097
2013	10	21	23	780.295
2013	10	21	24	706.594
2013	10	22	1	659.211
2013	10	22	2	638.806
2013	10	22	3	618.840
2013	10	22	4	615.875
2013	10	22	5	630.674
2013	10	22	6	681.986
2013	10	22	7	782.094
2013	10	22	8	854.701
2013	10	22	9	863.139
2013	10	22	10	873.094
2013	10	22	11	888.434
2013	10	22	12	888.287
2013	10	22	13	878.282
2013	10	22	14	882.450
2013	10	22	15	874.880
2013	10	22	16	869.735
2013	10	22	17	870.462
2013	10	22	18	879.586
2013	10	22	19	932.139
2013	10	22	20	951.892
2013	10	22	21	918.495
2013	10	22	22	866.940
2013	10	22	23	787.554
2013	10	22	24	717.742
2013	10	23	1	678.548
2013	10	23	2	654.431
2013	10	23	3	636.544
2013	10	23	4	633.451
2013	10	23	5	648.873
2013	10	23	6	707.676
2013	10	23	7	811.298
2013	10	23	8	879.112
2013	10	23	9	887.042
2013	10	23	10	898.016
2013	10	23	11	905.067
2013	10	23	12	907.455
2013	10	23	13	907.282
2013	10	23	14	902.377
2013	10	23	15	898.893
2013	10	23	16	895.189
2013	10	23	17	891.837
2013	10	23	18	902.516
2013	10	23	19	958.344
2013	10	23	20	967.538
2013	10	23	21	937.702

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	23	22	882.810
2013	10	23	23	807.625
2013	10	23	24	743.628
2013	10	24	1	695.875
2013	10	24	2	669.241
2013	10	24	3	656.919
2013	10	24	4	651.504
2013	10	24	5	671.683
2013	10	24	6	729.088
2013	10	24	7	829.885
2013	10	24	8	898.849
2013	10	24	9	893.879
2013	10	24	10	900.066
2013	10	24	11	910.862
2013	10	24	12	903.632
2013	10	24	13	900.104
2013	10	24	14	901.268
2013	10	24	15	890.550
2013	10	24	16	888.965
2013	10	24	17	898.359
2013	10	24	18	902.818
2013	10	24	19	961.858
2013	10	24	20	969.659
2013	10	24	21	938.154
2013	10	24	22	886.046
2013	10	24	23	811.190
2013	10	24	24	738.958
2013	10	25	1	694.186
2013	10	25	2	666.387
2013	10	25	3	653.822
2013	10	25	4	650.146
2013	10	25	5	663.036
2013	10	25	6	715.750
2013	10	25	7	819.684
2013	10	25	8	884.074
2013	10	25	9	888.426
2013	10	25	10	895.288
2013	10	25	11	901.025
2013	10	25	12	907.865
2013	10	25	13	890.027
2013	10	25	14	891.397
2013	10	25	15	878.628
2013	10	25	16	870.292
2013	10	25	17	862.420
2013	10	25	18	860.633
2013	10	25	19	905.525
2013	10	25	20	909.262
2013	10	25	21	884.107
2013	10	25	22	842.586
2013	10	25	23	788.469

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	25	24	728.575
2013	10	26	1	679.985
2013	10	26	2	651.934
2013	10	26	3	640.744
2013	10	26	4	628.636
2013	10	26	5	633.962
2013	10	26	6	650.118
2013	10	26	7	693.498
2013	10	26	8	747.431
2013	10	26	9	777.508
2013	10	26	10	821.001
2013	10	26	11	835.660
2013	10	26	12	840.937
2013	10	26	13	833.816
2013	10	26	14	823.677
2013	10	26	15	820.822
2013	10	26	16	816.219
2013	10	26	17	822.951
2013	10	26	18	838.315
2013	10	26	19	881.912
2013	10	26	20	876.037
2013	10	26	21	848.973
2013	10	26	22	817.172
2013	10	26	23	763.916
2013	10	26	24	720.692
2013	10	27	1	669.838
2013	10	27	2	646.941
2013	10	27	3	628.447
2013	10	27	4	618.838
2013	10	27	5	621.550
2013	10	27	6	629.660
2013	10	27	7	655.911
2013	10	27	8	689.047
2013	10	27	9	711.197
2013	10	27	10	740.101
2013	10	27	11	763.522
2013	10	27	12	772.521
2013	10	27	13	776.763
2013	10	27	14	778.239
2013	10	27	15	781.911
2013	10	27	16	780.187
2013	10	27	17	795.607
2013	10	27	18	820.977
2013	10	27	19	878.793
2013	10	27	20	884.436
2013	10	27	21	861.172
2013	10	27	22	815.693
2013	10	27	23	756.378
2013	10	27	24	707.092
2013	10	28	1	659.187

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	28	2	641.662
2013	10	28	3	633.329
2013	10	28	4	630.807
2013	10	28	5	649.898
2013	10	28	6	707.963
2013	10	28	7	807.038
2013	10	28	8	887.869
2013	10	28	9	892.331
2013	10	28	10	895.717
2013	10	28	11	905.488
2013	10	28	12	905.427
2013	10	28	13	901.263
2013	10	28	14	893.203
2013	10	28	15	887.788
2013	10	28	16	877.904
2013	10	28	17	875.830
2013	10	28	18	890.406
2013	10	28	19	960.730
2013	10	28	20	968.836
2013	10	28	21	946.257
2013	10	28	22	896.412
2013	10	28	23	817.274
2013	10	28	24	755.967
2013	10	29	1	708.562
2013	10	29	2	683.121
2013	10	29	3	681.277
2013	10	29	4	674.022
2013	10	29	5	693.135
2013	10	29	6	749.445
2013	10	29	7	851.430
2013	10	29	8	926.545
2013	10	29	9	926.386
2013	10	29	10	922.275
2013	10	29	11	924.226
2013	10	29	12	910.969
2013	10	29	13	915.601
2013	10	29	14	903.049
2013	10	29	15	895.295
2013	10	29	16	885.368
2013	10	29	17	888.151
2013	10	29	18	911.819
2013	10	29	19	973.850
2013	10	29	20	971.845
2013	10	29	21	946.816
2013	10	29	22	891.721
2013	10	29	23	814.070
2013	10	29	24	746.121
2013	10	30	1	698.730
2013	10	30	2	678.001
2013	10	30	3	660.874

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	10	30	4	659.464
2013	10	30	5	671.572
2013	10	30	6	728.885
2013	10	30	7	826.071
2013	10	30	8	904.287
2013	10	30	9	913.924
2013	10	30	10	915.463
2013	10	30	11	920.443
2013	10	30	12	920.768
2013	10	30	13	912.389
2013	10	30	14	906.392
2013	10	30	15	898.718
2013	10	30	16	882.710
2013	10	30	17	878.501
2013	10	30	18	891.960
2013	10	30	19	950.233
2013	10	30	20	951.935
2013	10	30	21	928.319
2013	10	30	22	874.255
2013	10	30	23	806.616
2013	10	30	24	740.939
2013	10	31	1	691.913
2013	10	31	2	667.195
2013	10	31	3	651.321
2013	10	31	4	648.786
2013	10	31	5	659.103
2013	10	31	6	714.894
2013	10	31	7	816.768
2013	10	31	8	889.715
2013	10	31	9	908.342
2013	10	31	10	915.966
2013	10	31	11	932.740
2013	10	31	12	940.687
2013	10	31	13	925.973
2013	10	31	14	928.417
2013	10	31	15	923.683
2013	10	31	16	919.560
2013	10	31	17	919.928
2013	10	31	18	932.414
2013	10	31	19	945.753
2013	10	31	20	922.012
2013	10	31	21	893.420
2013	10	31	22	852.371
2013	10	31	23	786.703
2013	10	31	24	721.789
2013	11	1	1	688.568
2013	11	1	2	661.138
2013	11	1	3	643.119
2013	11	1	4	640.375
2013	11	1	5	653.703

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	1	6	696.026
2013	11	1	7	791.342
2013	11	1	8	865.262
2013	11	1	9	870.167
2013	11	1	10	867.350
2013	11	1	11	876.007
2013	11	1	12	876.963
2013	11	1	13	867.892
2013	11	1	14	861.293
2013	11	1	15	846.594
2013	11	1	16	837.672
2013	11	1	17	839.849
2013	11	1	18	867.633
2013	11	1	19	902.054
2013	11	1	20	886.645
2013	11	1	21	861.588
2013	11	1	22	815.772
2013	11	1	23	759.938
2013	11	1	24	700.583
2013	11	2	1	658.772
2013	11	2	2	629.686
2013	11	2	3	614.391
2013	11	2	4	608.443
2013	11	2	5	605.523
2013	11	2	6	626.381
2013	11	2	7	664.137
2013	11	2	8	712.978
2013	11	2	9	746.847
2013	11	2	10	773.288
2013	11	2	11	788.382
2013	11	2	12	800.449
2013	11	2	13	797.921
2013	11	2	14	799.769
2013	11	2	15	799.153
2013	11	2	16	802.255
2013	11	2	17	814.919
2013	11	2	18	842.051
2013	11	2	19	878.815
2013	11	2	20	870.562
2013	11	2	21	850.263
2013	11	2	22	811.907
2013	11	2	23	770.490
2013	11	2	24	717.826
2013	11	3	1	674.374
2013	11	3	2	650.738
2013	11	4	3	631.107
2013	11	3	4	622.718
2013	11	3	5	621.036
2013	11	3	6	626.972
2013	11	3	7	648.957

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	3	8	683.484
2013	11	3	9	705.831
2013	11	3	10	757.656
2013	11	3	11	786.815
2013	11	3	12	799.720
2013	11	3	13	804.482
2013	11	3	14	807.976
2013	11	3	15	802.227
2013	11	3	16	801.027
2013	11	3	17	801.781
2013	11	3	18	835.558
2013	11	3	19	925.965
2013	11	3	20	938.774
2013	11	3	21	911.136
2013	11	3	22	881.229
2013	11	3	23	828.750
2013	11	3	24	773.324
2013	11	3	25	727.178
2013	11	4	1	690.385
2013	11	4	2	674.624
2013	11	4	3	670.248
2013	11	4	4	676.922
2013	11	4	5	697.328
2013	11	4	6	765.414
2013	11	4	7	861.919
2013	11	4	8	903.497
2013	11	4	9	916.285
2013	11	4	10	925.142
2013	11	4	11	925.023
2013	11	4	12	927.662
2013	11	4	13	915.721
2013	11	4	14	913.846
2013	11	4	15	904.926
2013	11	4	16	914.874
2013	11	4	17	941.714
2013	11	4	18	1,018.265
2013	11	4	19	1,013.519
2013	11	4	20	986.505
2013	11	4	21	951.441
2013	11	4	22	888.501
2013	11	4	23	813.871
2013	11	4	24	746.706
2013	11	5	1	706.707
2013	11	5	2	684.149
2013	11	5	3	673.320
2013	11	5	4	673.839
2013	11	5	5	693.796
2013	11	5	6	754.542
2013	11	5	7	848.453
2013	11	5	8	885.769

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	5	9	897.550
2013	11	5	10	909.413
2013	11	5	11	914.539
2013	11	5	12	912.290
2013	11	5	13	904.697
2013	11	5	14	906.025
2013	11	5	15	896.953
2013	11	5	16	888.056
2013	11	5	17	917.879
2013	11	5	18	983.965
2013	11	5	19	985.423
2013	11	5	20	953.309
2013	11	5	21	919.949
2013	11	5	22	863.397
2013	11	5	23	788.091
2013	11	5	24	724.780
2013	11	6	1	682.404
2013	11	6	2	662.790
2013	11	6	3	649.529
2013	11	6	4	643.065
2013	11	6	5	662.559
2013	11	6	6	711.911
2013	11	6	7	808.642
2013	11	6	8	847.234
2013	11	6	9	864.109
2013	11	6	10	874.274
2013	11	6	11	883.930
2013	11	6	12	891.927
2013	11	6	13	886.792
2013	11	6	14	890.767
2013	11	6	15	884.759
2013	11	6	16	884.061
2013	11	6	17	906.402
2013	11	6	18	972.372
2013	11	6	19	966.391
2013	11	6	20	940.322
2013	11	6	21	903.143
2013	11	6	22	842.489
2013	11	6	23	766.433
2013	11	6	24	716.803
2013	11	7	1	663.851
2013	11	7	2	644.579
2013	11	7	3	631.794
2013	11	7	4	624.425
2013	11	7	5	640.898
2013	11	7	6	695.548
2013	11	7	7	790.334
2013	11	7	8	847.916
2013	11	7	9	880.945
2013	11	7	10	898.517

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	7	11	913.492
2013	11	7	12	911.384
2013	11	7	13	913.710
2013	11	7	14	917.175
2013	11	7	15	915.102
2013	11	7	16	919.041
2013	11	7	17	944.164
2013	11	7	18	1,004.144
2013	11	7	19	994.980
2013	11	7	20	969.315
2013	11	7	21	939.148
2013	11	7	22	879.484
2013	11	7	23	810.101
2013	11	7	24	749.358
2013	11	8	1	702.887
2013	11	8	2	679.652
2013	11	8	3	665.296
2013	11	8	4	666.392
2013	11	8	5	681.445
2013	11	8	6	742.275
2013	11	8	7	831.979
2013	11	8	8	876.742
2013	11	8	9	899.800
2013	11	8	10	915.014
2013	11	8	11	930.871
2013	11	8	12	927.142
2013	11	8	13	925.391
2013	11	8	14	922.230
2013	11	8	15	908.428
2013	11	8	16	900.992
2013	11	8	17	916.367
2013	11	8	18	973.434
2013	11	8	19	966.219
2013	11	8	20	940.678
2013	11	8	21	911.338
2013	11	8	22	864.853
2013	11	8	23	803.124
2013	11	8	24	742.758
2013	11	9	1	697.752
2013	11	9	2	672.445
2013	11	9	3	654.857
2013	11	9	4	649.573
2013	11	9	5	654.128
2013	11	9	6	675.237
2013	11	9	7	718.351
2013	11	9	8	746.088
2013	11	9	9	795.562
2013	11	9	10	831.255
2013	11	9	11	839.435
2013	11	9	12	837.459

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	9	13	819.379
2013	11	9	14	819.161
2013	11	9	15	817.482
2013	11	9	16	823.724
2013	11	9	17	849.736
2013	11	9	18	913.747
2013	11	9	19	901.999
2013	11	9	20	877.322
2013	11	9	21	849.348
2013	11	9	22	814.920
2013	11	9	23	761.030
2013	11	9	24	708.150
2013	11	10	1	667.277
2013	11	10	2	633.633
2013	11	10	3	622.947
2013	11	10	4	614.884
2013	11	10	5	613.255
2013	11	10	6	629.798
2013	11	10	7	654.055
2013	11	10	8	672.778
2013	11	10	9	711.735
2013	11	10	10	741.181
2013	11	10	11	765.776
2013	11	10	12	788.783
2013	11	10	13	795.493
2013	11	10	14	800.819
2013	11	10	15	803.085
2013	11	10	16	814.253
2013	11	10	17	872.677
2013	11	10	18	928.632
2013	11	10	19	916.903
2013	11	10	20	890.142
2013	11	10	21	866.922
2013	11	10	22	819.074
2013	11	10	23	771.627
2013	11	10	24	726.312
2013	11	11	1	684.100
2013	11	11	2	662.971
2013	11	11	3	653.565
2013	11	11	4	654.283
2013	11	11	5	678.368
2013	11	11	6	719.002
2013	11	11	7	803.806
2013	11	11	8	848.436
2013	11	11	9	885.244
2013	11	11	10	916.193
2013	11	11	11	937.101
2013	11	11	12	939.573
2013	11	11	13	949.893
2013	11	11	14	948.497

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	11	15	937.394
2013	11	11	16	947.362
2013	11	11	17	981.484
2013	11	11	18	1,027.829
2013	11	11	19	1,023.944
2013	11	11	20	1,002.817
2013	11	11	21	965.955
2013	11	11	22	915.247
2013	11	11	23	838.154
2013	11	11	24	771.614
2013	11	12	1	720.919
2013	11	12	2	702.164
2013	11	12	3	689.170
2013	11	12	4	691.700
2013	11	12	5	716.927
2013	11	12	6	774.185
2013	11	12	7	882.580
2013	11	12	8	925.407
2013	11	12	9	950.318
2013	11	12	10	962.740
2013	11	12	11	969.677
2013	11	12	12	966.532
2013	11	12	13	958.573
2013	11	12	14	960.809
2013	11	12	15	961.853
2013	11	12	16	970.170
2013	11	12	17	994.789
2013	11	12	18	1,068.478
2013	11	12	19	1,066.435
2013	11	12	20	1,036.541
2013	11	12	21	1,002.106
2013	11	12	22	939.427
2013	11	12	23	862.010
2013	11	12	24	791.343
2013	11	13	1	748.053
2013	11	13	2	726.736
2013	11	13	3	722.458
2013	11	13	4	719.263
2013	11	13	5	739.642
2013	11	13	6	807.519
2013	11	13	7	907.534
2013	11	13	8	933.757
2013	11	13	9	946.060
2013	11	13	10	962.482
2013	11	13	11	968.127
2013	11	13	12	962.134
2013	11	13	13	957.715
2013	11	13	14	946.878
2013	11	13	15	941.896
2013	11	13	16	935.799

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	13	17	973.307
2013	11	13	18	1,043.678
2013	11	13	19	1,034.737
2013	11	13	20	1,018.408
2013	11	13	21	986.123
2013	11	13	22	935.358
2013	11	13	23	855.028
2013	11	13	24	785.051
2013	11	14	1	743.422
2013	11	14	2	718.239
2013	11	14	3	707.220
2013	11	14	4	705.625
2013	11	14	5	721.551
2013	11	14	6	782.715
2013	11	14	7	881.851
2013	11	14	8	915.821
2013	11	14	9	928.217
2013	11	14	10	944.149
2013	11	14	11	940.083
2013	11	14	12	938.109
2013	11	14	13	925.451
2013	11	14	14	916.143
2013	11	14	15	905.760
2013	11	14	16	904.822
2013	11	14	17	930.741
2013	11	14	18	1,009.821
2013	11	14	19	1,007.670
2013	11	14	20	986.114
2013	11	14	21	952.495
2013	11	14	22	893.177
2013	11	14	23	823.637
2013	11	14	24	759.497
2013	11	15	1	717.341
2013	11	15	2	690.867
2013	11	15	3	676.884
2013	11	15	4	674.957
2013	11	15	5	695.126
2013	11	15	6	746.891
2013	11	15	7	841.343
2013	11	15	8	882.917
2013	11	15	9	901.630
2013	11	15	10	910.732
2013	11	15	11	919.655
2013	11	15	12	910.231
2013	11	15	13	900.151
2013	11	15	14	892.636
2013	11	15	15	884.458
2013	11	15	16	885.461
2013	11	15	17	918.245
2013	11	15	18	969.352

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	15	19	951.488
2013	11	15	20	921.371
2013	11	15	21	892.465
2013	11	15	22	852.682
2013	11	15	23	786.449
2013	11	15	24	730.652
2013	11	16	1	686.324
2013	11	16	2	656.673
2013	11	16	3	639.718
2013	11	16	4	637.021
2013	11	16	5	643.281
2013	11	16	6	669.475
2013	11	16	7	698.091
2013	11	16	8	729.205
2013	11	16	9	754.292
2013	11	16	10	783.406
2013	11	16	11	790.981
2013	11	16	12	783.748
2013	11	16	13	777.968
2013	11	16	14	765.024
2013	11	16	15	751.667
2013	11	16	16	757.834
2013	11	16	17	792.012
2013	11	16	18	881.210
2013	11	16	19	874.995
2013	11	16	20	850.499
2013	11	16	21	829.138
2013	11	16	22	793.754
2013	11	16	23	746.465
2013	11	16	24	694.963
2013	11	17	1	651.908
2013	11	17	2	629.956
2013	11	17	3	613.631
2013	11	17	4	602.969
2013	11	17	5	604.257
2013	11	17	6	618.163
2013	11	17	7	642.564
2013	11	17	8	672.152
2013	11	17	9	713.461
2013	11	17	10	745.330
2013	11	17	11	764.724
2013	11	17	12	780.898
2013	11	17	13	788.076
2013	11	17	14	796.889
2013	11	17	15	793.233
2013	11	17	16	792.659
2013	11	17	17	838.477
2013	11	17	18	910.348
2013	11	17	19	902.535
2013	11	17	20	880.071

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	17	21	850.683
2013	11	17	22	793.553
2013	11	17	23	745.057
2013	11	17	24	691.595
2013	11	18	1	651.875
2013	11	18	2	626.152
2013	11	18	3	619.492
2013	11	18	4	622.430
2013	11	18	5	641.047
2013	11	18	6	699.287
2013	11	18	7	802.312
2013	11	18	8	852.989
2013	11	18	9	871.677
2013	11	18	10	887.445
2013	11	18	11	905.293
2013	11	18	12	909.371
2013	11	18	13	910.213
2013	11	18	14	910.815
2013	11	18	15	914.347
2013	11	18	16	918.541
2013	11	18	17	966.142
2013	11	18	18	1,023.347
2013	11	18	19	1,009.939
2013	11	18	20	988.356
2013	11	18	21	954.911
2013	11	18	22	898.528
2013	11	18	23	826.625
2013	11	18	24	760.240
2013	11	19	1	717.454
2013	11	19	2	689.493
2013	11	19	3	675.014
2013	11	19	4	675.571
2013	11	19	5	695.653
2013	11	19	6	746.936
2013	11	19	7	853.902
2013	11	19	8	909.141
2013	11	19	9	929.699
2013	11	19	10	942.346
2013	11	19	11	950.130
2013	11	19	12	958.272
2013	11	19	13	946.177
2013	11	19	14	945.571
2013	11	19	15	934.095
2013	11	19	16	930.806
2013	11	19	17	961.269
2013	11	19	18	1,034.335
2013	11	19	19	1,029.471
2013	11	19	20	1,007.957
2013	11	19	21	978.232
2013	11	19	22	916.208

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	19	23	848.045
2013	11	19	24	781.879
2013	11	20	1	738.253
2013	11	20	2	718.791
2013	11	20	3	703.450
2013	11	20	4	710.436
2013	11	20	5	725.633
2013	11	20	6	794.591
2013	11	20	7	891.433
2013	11	20	8	930.938
2013	11	20	9	937.344
2013	11	20	10	942.189
2013	11	20	11	944.826
2013	11	20	12	936.810
2013	11	20	13	932.213
2013	11	20	14	923.261
2013	11	20	15	918.111
2013	11	20	16	922.546
2013	11	20	17	972.417
2013	11	20	18	1,035.966
2013	11	20	19	1,036.614
2013	11	20	20	1,005.409
2013	11	20	21	977.416
2013	11	20	22	922.452
2013	11	20	23	842.613
2013	11	20	24	781.186
2013	11	21	1	736.076
2013	11	21	2	714.981
2013	11	21	3	701.933
2013	11	21	4	702.057
2013	11	21	5	724.425
2013	11	21	6	781.530
2013	11	21	7	878.982
2013	11	21	8	913.048
2013	11	21	9	929.930
2013	11	21	10	934.573
2013	11	21	11	942.396
2013	11	21	12	941.020
2013	11	21	13	933.986
2013	11	21	14	933.939
2013	11	21	15	928.252
2013	11	21	16	937.957
2013	11	21	17	977.541
2013	11	21	18	1,027.637
2013	11	21	19	1,011.163
2013	11	21	20	984.862
2013	11	21	21	950.362
2013	11	21	22	902.236
2013	11	21	23	818.108
2013	11	21	24	755.898

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	22	1	712.157
2013	11	22	2	689.389
2013	11	22	3	669.868
2013	11	22	4	663.792
2013	11	22	5	677.684
2013	11	22	6	734.307
2013	11	22	7	831.511
2013	11	22	8	889.027
2013	11	22	9	899.896
2013	11	22	10	916.099
2013	11	22	11	920.867
2013	11	22	12	929.423
2013	11	22	13	926.477
2013	11	22	14	919.181
2013	11	22	15	915.839
2013	11	22	16	924.819
2013	11	22	17	960.736
2013	11	22	18	977.054
2013	11	22	19	962.373
2013	11	22	20	934.921
2013	11	22	21	914.770
2013	11	22	22	868.224
2013	11	22	23	810.329
2013	11	22	24	749.320
2013	11	23	1	703.879
2013	11	23	2	676.215
2013	11	23	3	665.050
2013	11	23	4	655.539
2013	11	23	5	664.124
2013	11	23	6	686.929
2013	11	23	7	730.225
2013	11	23	8	760.201
2013	11	23	9	793.188
2013	11	23	10	820.386
2013	11	23	11	837.879
2013	11	23	12	839.284
2013	11	23	13	845.764
2013	11	23	14	855.995
2013	11	23	15	853.825
2013	11	23	16	859.203
2013	11	23	17	906.101
2013	11	23	18	986.056
2013	11	23	19	980.799
2013	11	23	20	959.140
2013	11	23	21	935.131
2013	11	23	22	900.230
2013	11	23	23	845.285
2013	11	23	24	794.584
2013	11	24	1	748.834
2013	11	24	2	723.937

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	24	3	709.367
2013	11	24	4	701.577
2013	11	24	5	705.495
2013	11	24	6	715.910
2013	11	24	7	749.081
2013	11	24	8	772.039
2013	11	24	9	804.257
2013	11	24	10	840.672
2013	11	24	11	856.060
2013	11	24	12	862.582
2013	11	24	13	867.920
2013	11	24	14	868.189
2013	11	24	15	872.166
2013	11	24	16	880.433
2013	11	24	17	931.135
2013	11	24	18	1,014.880
2013	11	24	19	1,014.013
2013	11	24	20	980.521
2013	11	24	21	956.162
2013	11	24	22	907.719
2013	11	24	23	842.638
2013	11	24	24	788.610
2013	11	25	1	744.307
2013	11	25	2	727.085
2013	11	25	3	711.887
2013	11	25	4	714.531
2013	11	25	5	735.516
2013	11	25	6	789.281
2013	11	25	7	896.148
2013	11	25	8	947.009
2013	11	25	9	964.209
2013	11	25	10	972.971
2013	11	25	11	985.490
2013	11	25	12	970.795
2013	11	25	13	968.979
2013	11	25	14	971.449
2013	11	25	15	970.763
2013	11	25	16	981.548
2013	11	25	17	1,015.621
2013	11	25	18	1,073.169
2013	11	25	19	1,061.310
2013	11	25	20	1,036.126
2013	11	25	21	1,002.773
2013	11	25	22	945.340
2013	11	25	23	863.404
2013	11	25	24	795.799
2013	11	26	1	747.808
2013	11	26	2	720.383
2013	11	26	3	710.924
2013	11	26	4	701.611

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	26	5	716.789
2013	11	26	6	780.021
2013	11	26	7	869.495
2013	11	26	8	936.524
2013	11	26	9	945.904
2013	11	26	10	958.726
2013	11	26	11	966.948
2013	11	26	12	967.184
2013	11	26	13	969.228
2013	11	26	14	968.688
2013	11	26	15	964.913
2013	11	26	16	967.597
2013	11	26	17	1,008.854
2013	11	26	18	1,051.481
2013	11	26	19	1,038.149
2013	11	26	20	1,012.476
2013	11	26	21	974.477
2013	11	26	22	923.017
2013	11	26	23	844.511
2013	11	26	24	781.462
2013	11	27	1	729.873
2013	11	27	2	705.836
2013	11	27	3	684.933
2013	11	27	4	684.608
2013	11	27	5	690.496
2013	11	27	6	740.280
2013	11	27	7	813.038
2013	11	27	8	871.450
2013	11	27	9	900.498
2013	11	27	10	933.420
2013	11	27	11	954.840
2013	11	27	12	967.057
2013	11	27	13	961.918
2013	11	27	14	966.120
2013	11	27	15	957.991
2013	11	27	16	947.637
2013	11	27	17	972.641
2013	11	27	18	1,037.225
2013	11	27	19	1,020.923
2013	11	27	20	1,003.512
2013	11	27	21	972.127
2013	11	27	22	927.757
2013	11	27	23	861.074
2013	11	27	24	796.072
2013	11	28	1	747.037
2013	11	28	2	716.613
2013	11	28	3	701.774
2013	11	28	4	694.647
2013	11	28	5	697.195
2013	11	28	6	709.543

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	28	7	742.429
2013	11	28	8	755.553
2013	11	28	9	789.098
2013	11	28	10	823.923
2013	11	28	11	839.869
2013	11	28	12	849.939
2013	11	28	13	841.342
2013	11	28	14	812.896
2013	11	28	15	784.789
2013	11	28	16	762.296
2013	11	28	17	785.296
2013	11	28	18	823.779
2013	11	28	19	815.858
2013	11	28	20	822.078
2013	11	28	21	818.281
2013	11	28	22	805.452
2013	11	28	23	775.655
2013	11	28	24	734.982
2013	11	29	1	704.731
2013	11	29	2	685.188
2013	11	29	3	671.764
2013	11	29	4	672.025
2013	11	29	5	680.308
2013	11	29	6	713.342
2013	11	29	7	750.379
2013	11	29	8	765.017
2013	11	29	9	787.737
2013	11	29	10	800.736
2013	11	29	11	810.400
2013	11	29	12	814.725
2013	11	29	13	808.475
2013	11	29	14	805.342
2013	11	29	15	801.152
2013	11	29	16	807.752
2013	11	29	17	855.885
2013	11	29	18	942.882
2013	11	29	19	940.613
2013	11	29	20	922.396
2013	11	29	21	907.834
2013	11	29	22	872.089
2013	11	29	23	820.380
2013	11	29	24	773.509
2013	11	30	1	737.195
2013	11	30	2	711.697
2013	11	30	3	696.917
2013	11	30	4	699.560
2013	11	30	5	702.315
2013	11	30	6	722.245
2013	11	30	7	755.141
2013	11	30	8	779.617

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	11	30	9	815.233
2013	11	30	10	835.758
2013	11	30	11	849.407
2013	11	30	12	851.920
2013	11	30	13	853.102
2013	11	30	14	848.068
2013	11	30	15	838.555
2013	11	30	16	846.434
2013	11	30	17	894.336
2013	11	30	18	959.482
2013	11	30	19	955.049
2013	11	30	20	937.846
2013	11	30	21	909.208
2013	11	30	22	871.820
2013	11	30	23	822.549
2013	11	30	24	763.465
2013	12	1	1	720.918
2013	12	1	2	686.503
2013	12	1	3	670.877
2013	12	1	4	662.582
2013	12	1	5	664.208
2013	12	1	6	676.074
2013	12	1	7	703.912
2013	12	1	8	725.193
2013	12	1	9	754.363
2013	12	1	10	787.983
2013	12	1	11	794.798
2013	12	1	12	807.796
2013	12	1	13	811.526
2013	12	1	14	813.975
2013	12	1	15	817.981
2013	12	1	16	839.128
2013	12	1	17	897.100
2013	12	1	18	969.640
2013	12	1	19	964.555
2013	12	1	20	941.236
2013	12	1	21	911.361
2013	12	1	22	862.970
2013	12	1	23	801.999
2013	12	1	24	738.042
2013	12	2	1	694.875
2013	12	2	2	677.598
2013	12	2	3	665.659
2013	12	2	4	669.448
2013	12	2	5	686.123
2013	12	2	6	746.492
2013	12	2	7	853.197
2013	12	2	8	912.565
2013	12	2	9	925.181
2013	12	2	10	935.207

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	2	11	944.059
2013	12	2	12	951.053
2013	12	2	13	945.740
2013	12	2	14	943.233
2013	12	2	15	938.620
2013	12	2	16	946.982
2013	12	2	17	990.424
2013	12	2	18	1,055.502
2013	12	2	19	1,049.150
2013	12	2	20	1,027.369
2013	12	2	21	993.984
2013	12	2	22	933.422
2013	12	2	23	853.682
2013	12	2	24	784.219
2013	12	3	1	736.879
2013	12	3	2	705.782
2013	12	3	3	696.635
2013	12	3	4	686.293
2013	12	3	5	713.684
2013	12	3	6	768.193
2013	12	3	7	875.747
2013	12	3	8	924.879
2013	12	3	9	932.368
2013	12	3	10	927.073
2013	12	3	11	933.150
2013	12	3	12	931.710
2013	12	3	13	926.529
2013	12	3	14	921.184
2013	12	3	15	914.337
2013	12	3	16	913.125
2013	12	3	17	966.071
2013	12	3	18	1,045.811
2013	12	3	19	1,046.203
2013	12	3	20	1,026.424
2013	12	3	21	992.075
2013	12	3	22	938.279
2013	12	3	23	858.486
2013	12	3	24	785.030
2013	12	4	1	731.866
2013	12	4	2	709.036
2013	12	4	3	695.338
2013	12	4	4	693.139
2013	12	4	5	711.231
2013	12	4	6	765.257
2013	12	4	7	869.342
2013	12	4	8	933.866
2013	12	4	9	937.305
2013	12	4	10	954.018
2013	12	4	11	945.969
2013	12	4	12	931.538

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	4	13	915.650
2013	12	4	14	916.271
2013	12	4	15	911.006
2013	12	4	16	915.259
2013	12	4	17	971.157
2013	12	4	18	1,039.495
2013	12	4	19	1,029.438
2013	12	4	20	1,014.667
2013	12	4	21	980.097
2013	12	4	22	926.947
2013	12	4	23	843.557
2013	12	4	24	769.314
2013	12	5	1	713.032
2013	12	5	2	697.309
2013	12	5	3	674.374
2013	12	5	4	671.900
2013	12	5	5	687.154
2013	12	5	6	744.109
2013	12	5	7	839.102
2013	12	5	8	896.468
2013	12	5	9	900.322
2013	12	5	10	902.621
2013	12	5	11	912.309
2013	12	5	12	909.169
2013	12	5	13	910.137
2013	12	5	14	909.773
2013	12	5	15	904.239
2013	12	5	16	914.040
2013	12	5	17	977.839
2013	12	5	18	1,018.498
2013	12	5	19	1,007.101
2013	12	5	20	983.477
2013	12	5	21	953.978
2013	12	5	22	904.299
2013	12	5	23	826.699
2013	12	5	24	756.858
2013	12	6	1	704.302
2013	12	6	2	682.223
2013	12	6	3	669.285
2013	12	6	4	669.914
2013	12	6	5	685.963
2013	12	6	6	742.056
2013	12	6	7	848.830
2013	12	6	8	914.346
2013	12	6	9	929.988
2013	12	6	10	941.047
2013	12	6	11	943.952
2013	12	6	12	954.028
2013	12	6	13	943.144
2013	12	6	14	948.376

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	6	15	937.833
2013	12	6	16	942.073
2013	12	6	17	990.724
2013	12	6	18	1,032.582
2013	12	6	19	1,019.362
2013	12	6	20	997.066
2013	12	6	21	968.456
2013	12	6	22	924.255
2013	12	6	23	852.579
2013	12	6	24	785.642
2013	12	7	1	729.669
2013	12	7	2	699.486
2013	12	7	3	690.777
2013	12	7	4	677.618
2013	12	7	5	686.620
2013	12	7	6	712.610
2013	12	7	7	759.780
2013	12	7	8	797.323
2013	12	7	9	833.266
2013	12	7	10	865.242
2013	12	7	11	871.705
2013	12	7	12	878.450
2013	12	7	13	870.057
2013	12	7	14	868.908
2013	12	7	15	870.732
2013	12	7	16	885.429
2013	12	7	17	940.426
2013	12	7	18	1,009.273
2013	12	7	19	997.567
2013	12	7	20	976.173
2013	12	7	21	955.308
2013	12	7	22	921.186
2013	12	7	23	871.051
2013	12	7	24	798.518
2013	12	8	1	752.753
2013	12	8	2	717.940
2013	12	8	3	705.279
2013	12	8	4	696.153
2013	12	8	5	698.644
2013	12	8	6	719.816
2013	12	8	7	748.017
2013	12	8	8	779.088
2013	12	8	9	804.020
2013	12	8	10	844.042
2013	12	8	11	855.865
2013	12	8	12	869.600
2013	12	8	13	865.286
2013	12	8	14	871.112
2013	12	8	15	871.335
2013	12	8	16	885.601

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	8	17	961.454
2013	12	8	18	1,032.431
2013	12	8	19	1,029.078
2013	12	8	20	1,004.924
2013	12	8	21	979.408
2013	12	8	22	926.961
2013	12	8	23	863.590
2013	12	8	24	790.857
2013	12	9	1	750.086
2013	12	9	2	725.287
2013	12	9	3	714.814
2013	12	9	4	711.499
2013	12	9	5	732.546
2013	12	9	6	785.300
2013	12	9	7	894.371
2013	12	9	8	950.436
2013	12	9	9	953.702
2013	12	9	10	971.009
2013	12	9	11	973.722
2013	12	9	12	980.829
2013	12	9	13	975.299
2013	12	9	14	975.896
2013	12	9	15	980.635
2013	12	9	16	998.564
2013	12	9	17	1,063.098
2013	12	9	18	1,099.035
2013	12	9	19	1,093.972
2013	12	9	20	1,068.925
2013	12	9	21	1,033.416
2013	12	9	22	979.902
2013	12	9	23	887.200
2013	12	9	24	812.857
2013	12	10	1	756.490
2013	12	10	2	734.673
2013	12	10	3	717.589
2013	12	10	4	722.295
2013	12	10	5	736.284
2013	12	10	6	801.057
2013	12	10	7	908.380
2013	12	10	8	974.549
2013	12	10	9	984.547
2013	12	10	10	987.292
2013	12	10	11	990.177
2013	12	10	12	997.737
2013	12	10	13	995.441
2013	12	10	14	992.409
2013	12	10	15	985.686
2013	12	10	16	988.357
2013	12	10	17	1,042.336
2013	12	10	18	1,122.220

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	10	19	1,116.919
2013	12	10	20	1,096.846
2013	12	10	21	1,067.304
2013	12	10	22	1,015.345
2013	12	10	23	930.752
2013	12	10	24	850.961
2013	12	11	1	795.701
2013	12	11	2	770.870
2013	12	11	3	756.309
2013	12	11	4	750.294
2013	12	11	5	772.325
2013	12	11	6	832.230
2013	12	11	7	944.142
2013	12	11	8	989.083
2013	12	11	9	989.929
2013	12	11	10	994.578
2013	12	11	11	1,004.701
2013	12	11	12	1,006.614
2013	12	11	13	1,003.763
2013	12	11	14	1,002.073
2013	12	11	15	1,002.787
2013	12	11	16	1,008.808
2013	12	11	17	1,058.699
2013	12	11	18	1,137.670
2013	12	11	19	1,124.094
2013	12	11	20	1,110.691
2013	12	11	21	1,076.547
2013	12	11	22	1,021.426
2013	12	11	23	941.555
2013	12	11	24	856.453
2013	12	12	1	803.348
2013	12	12	2	784.702
2013	12	12	3	765.441
2013	12	12	4	769.935
2013	12	12	5	786.121
2013	12	12	6	844.220
2013	12	12	7	956.496
2013	12	12	8	1,005.255
2013	12	12	9	1,007.280
2013	12	12	10	1,016.026
2013	12	12	11	1,023.473
2013	12	12	12	1,019.441
2013	12	12	13	1,017.150
2013	12	12	14	1,013.995
2013	12	12	15	1,012.352
2013	12	12	16	1,021.586
2013	12	12	17	1,080.326
2013	12	12	18	1,150.456
2013	12	12	19	1,145.856
2013	12	12	20	1,124.545

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	12	21	1,090.591
2013	12	12	22	1,040.530
2013	12	12	23	953.320
2013	12	12	24	867.465
2013	12	13	1	817.288
2013	12	13	2	789.639
2013	12	13	3	777.704
2013	12	13	4	769.428
2013	12	13	5	790.038
2013	12	13	6	840.470
2013	12	13	7	940.326
2013	12	13	8	996.078
2013	12	13	9	1,004.591
2013	12	13	10	1,019.277
2013	12	13	11	1,022.438
2013	12	13	12	1,028.366
2013	12	13	13	1,010.692
2013	12	13	14	1,014.225
2013	12	13	15	1,003.884
2013	12	13	16	1,007.941
2013	12	13	17	1,055.376
2013	12	13	18	1,114.612
2013	12	13	19	1,104.031
2013	12	13	20	1,082.818
2013	12	13	21	1,047.234
2013	12	13	22	1,006.680
2013	12	13	23	930.100
2013	12	13	24	853.949
2013	12	14	1	798.074
2013	12	14	2	765.072
2013	12	14	3	748.924
2013	12	14	4	750.035
2013	12	14	5	754.262
2013	12	14	6	779.387
2013	12	14	7	827.633
2013	12	14	8	871.040
2013	12	14	9	903.575
2013	12	14	10	942.205
2013	12	14	11	952.664
2013	12	14	12	953.372
2013	12	14	13	948.054
2013	12	14	14	945.865
2013	12	14	15	944.491
2013	12	14	16	957.812
2013	12	14	17	1,022.222
2013	12	14	18	1,089.192
2013	12	14	19	1,065.138
2013	12	14	20	1,043.962
2013	12	14	21	1,015.512
2013	12	14	22	976.466

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	14	23	909.668
2013	12	14	24	841.432
2013	12	15	1	779.337
2013	12	15	2	744.913
2013	12	15	3	726.310
2013	12	15	4	716.247
2013	12	15	5	717.510
2013	12	15	6	731.488
2013	12	15	7	760.638
2013	12	15	8	792.939
2013	12	15	9	829.627
2013	12	15	10	866.658
2013	12	15	11	883.734
2013	12	15	12	895.563
2013	12	15	13	896.708
2013	12	15	14	898.239
2013	12	15	15	897.597
2013	12	15	16	906.751
2013	12	15	17	973.846
2013	12	15	18	1,066.472
2013	12	15	19	1,050.915
2013	12	15	20	1,037.852
2013	12	15	21	1,011.816
2013	12	15	22	963.528
2013	12	15	23	895.047
2013	12	15	24	830.328
2013	12	16	1	779.441
2013	12	16	2	755.041
2013	12	16	3	742.543
2013	12	16	4	747.394
2013	12	16	5	770.131
2013	12	16	6	825.116
2013	12	16	7	936.092
2013	12	16	8	996.664
2013	12	16	9	1,009.483
2013	12	16	10	1,014.907
2013	12	16	11	1,018.113
2013	12	16	12	1,008.701
2013	12	16	13	1,005.310
2013	12	16	14	1,005.404
2013	12	16	15	1,007.983
2013	12	16	16	1,001.269
2013	12	16	17	1,054.049
2013	12	16	18	1,155.155
2013	12	16	19	1,157.655
2013	12	16	20	1,138.904
2013	12	16	21	1,118.302
2013	12	16	22	1,056.717
2013	12	16	23	979.118
2013	12	16	24	894.372

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	17	1	842.138
2013	12	17	2	809.055
2013	12	17	3	800.428
2013	12	17	4	796.525
2013	12	17	5	816.352
2013	12	17	6	865.650
2013	12	17	7	970.979
2013	12	17	8	1,027.625
2013	12	17	9	1,026.760
2013	12	17	10	1,040.330
2013	12	17	11	1,059.080
2013	12	17	12	1,049.841
2013	12	17	13	1,033.765
2013	12	17	14	1,028.907
2013	12	17	15	1,026.579
2013	12	17	16	1,024.151
2013	12	17	17	1,075.393
2013	12	17	18	1,135.751
2013	12	17	19	1,129.952
2013	12	17	20	1,099.119
2013	12	17	21	1,079.461
2013	12	17	22	1,019.519
2013	12	17	23	938.420
2013	12	17	24	849.368
2013	12	18	1	792.820
2013	12	18	2	763.107
2013	12	18	3	747.794
2013	12	18	4	745.610
2013	12	18	5	757.773
2013	12	18	6	824.606
2013	12	18	7	922.972
2013	12	18	8	982.822
2013	12	18	9	978.114
2013	12	18	10	973.554
2013	12	18	11	987.986
2013	12	18	12	988.169
2013	12	18	13	979.949
2013	12	18	14	981.142
2013	12	18	15	974.460
2013	12	18	16	984.963
2013	12	18	17	1,027.088
2013	12	18	18	1,116.523
2013	12	18	19	1,112.822
2013	12	18	20	1,087.439
2013	12	18	21	1,055.342
2013	12	18	22	1,006.545
2013	12	18	23	916.798
2013	12	18	24	836.063
2013	12	19	1	774.579
2013	12	19	2	747.956

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	19	3	732.927
2013	12	19	4	729.004
2013	12	19	5	749.536
2013	12	19	6	808.726
2013	12	19	7	908.824
2013	12	19	8	961.743
2013	12	19	9	956.362
2013	12	19	10	954.859
2013	12	19	11	951.911
2013	12	19	12	946.039
2013	12	19	13	934.344
2013	12	19	14	934.302
2013	12	19	15	929.100
2013	12	19	16	935.228
2013	12	19	17	994.262
2013	12	19	18	1,067.269
2013	12	19	19	1,063.041
2013	12	19	20	1,042.560
2013	12	19	21	1,017.523
2013	12	19	22	961.753
2013	12	19	23	883.781
2013	12	19	24	800.973
2013	12	20	1	745.168
2013	12	20	2	705.851
2013	12	20	3	694.025
2013	12	20	4	683.568
2013	12	20	5	709.147
2013	12	20	6	755.487
2013	12	20	7	863.141
2013	12	20	8	929.557
2013	12	20	9	934.068
2013	12	20	10	942.010
2013	12	20	11	940.357
2013	12	20	12	947.190
2013	12	20	13	937.296
2013	12	20	14	935.129
2013	12	20	15	925.598
2013	12	20	16	937.464
2013	12	20	17	980.238
2013	12	20	18	1,023.040
2013	12	20	19	1,003.587
2013	12	20	20	980.202
2013	12	20	21	949.958
2013	12	20	22	911.909
2013	12	20	23	847.751
2013	12	20	24	773.096
2013	12	21	1	710.211
2013	12	21	2	680.280
2013	12	21	3	656.525
2013	12	21	4	648.229

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	21	5	651.706
2013	12	21	6	669.939
2013	12	21	7	710.169
2013	12	21	8	757.319
2013	12	21	9	796.877
2013	12	21	10	827.500
2013	12	21	11	849.566
2013	12	21	12	858.853
2013	12	21	13	854.389
2013	12	21	14	850.549
2013	12	21	15	843.336
2013	12	21	16	859.095
2013	12	21	17	921.709
2013	12	21	18	975.602
2013	12	21	19	963.647
2013	12	21	20	943.949
2013	12	21	21	928.162
2013	12	21	22	896.021
2013	12	21	23	832.622
2013	12	21	24	774.471
2013	12	22	1	736.984
2013	12	22	2	700.964
2013	12	22	3	682.516
2013	12	22	4	667.781
2013	12	22	5	656.865
2013	12	22	6	678.380
2013	12	22	7	707.614
2013	12	22	8	744.149
2013	12	22	9	778.343
2013	12	22	10	823.936
2013	12	22	11	843.484
2013	12	22	12	854.423
2013	12	22	13	859.911
2013	12	22	14	868.623
2013	12	22	15	864.115
2013	12	22	16	866.959
2013	12	22	17	915.606
2013	12	22	18	973.844
2013	12	22	19	970.746
2013	12	22	20	948.792
2013	12	22	21	924.538
2013	12	22	22	884.248
2013	12	22	23	820.228
2013	12	22	24	756.417
2013	12	23	1	697.855
2013	12	23	2	671.888
2013	12	23	3	653.581
2013	12	23	4	648.683
2013	12	23	5	665.495
2013	12	23	6	716.492

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	23	7	793.211
2013	12	23	8	870.674
2013	12	23	9	901.593
2013	12	23	10	929.739
2013	12	23	11	940.011
2013	12	23	12	953.042
2013	12	23	13	942.044
2013	12	23	14	951.352
2013	12	23	15	950.050
2013	12	23	16	936.006
2013	12	23	17	986.746
2013	12	23	18	1,051.939
2013	12	23	19	1,045.046
2013	12	23	20	1,021.885
2013	12	23	21	998.716
2013	12	23	22	956.108
2013	12	23	23	895.062
2013	12	23	24	822.374
2013	12	24	1	764.622
2013	12	24	2	724.756
2013	12	24	3	704.967
2013	12	24	4	699.392
2013	12	24	5	706.002
2013	12	24	6	744.631
2013	12	24	7	796.246
2013	12	24	8	850.246
2013	12	24	9	876.823
2013	12	24	10	910.733
2013	12	24	11	931.415
2013	12	24	12	934.304
2013	12	24	13	924.582
2013	12	24	14	905.010
2013	12	24	15	900.722
2013	12	24	16	887.798
2013	12	24	17	925.829
2013	12	24	18	996.948
2013	12	24	19	968.223
2013	12	24	20	935.989
2013	12	24	21	925.570
2013	12	24	22	905.828
2013	12	24	23	875.603
2013	12	24	24	830.970
2013	12	25	1	785.270
2013	12	25	2	748.198
2013	12	25	3	724.945
2013	12	25	4	717.355
2013	12	25	5	724.619
2013	12	25	6	743.125
2013	12	25	7	771.516
2013	12	25	8	803.469

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	25	9	819.447
2013	12	25	10	842.330
2013	12	25	11	851.993
2013	12	25	12	856.810
2013	12	25	13	848.069
2013	12	25	14	834.124
2013	12	25	15	830.115
2013	12	25	16	828.064
2013	12	25	17	854.004
2013	12	25	18	916.258
2013	12	25	19	906.763
2013	12	25	20	899.508
2013	12	25	21	894.331
2013	12	25	22	872.752
2013	12	25	23	825.171
2013	12	25	24	769.500
2013	12	26	1	727.931
2013	12	26	2	703.192
2013	12	26	3	684.128
2013	12	26	4	682.606
2013	12	26	5	699.526
2013	12	26	6	742.003
2013	12	26	7	807.837
2013	12	26	8	867.266
2013	12	26	9	886.333
2013	12	26	10	923.414
2013	12	26	11	940.055
2013	12	26	12	949.171
2013	12	26	13	948.435
2013	12	26	14	944.752
2013	12	26	15	935.364
2013	12	26	16	930.061
2013	12	26	17	960.077
2013	12	26	18	1,050.602
2013	12	26	19	1,045.145
2013	12	26	20	1,026.495
2013	12	26	21	996.005
2013	12	26	22	948.688
2013	12	26	23	881.153
2013	12	26	24	816.445
2013	12	27	1	773.900
2013	12	27	2	739.332
2013	12	27	3	728.192
2013	12	27	4	719.697
2013	12	27	5	728.121
2013	12	27	6	769.607
2013	12	27	7	830.750
2013	12	27	8	883.831
2013	12	27	9	906.193
2013	12	27	10	934.725

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	27	11	965.083
2013	12	27	12	960.815
2013	12	27	13	956.460
2013	12	27	14	946.063
2013	12	27	15	927.477
2013	12	27	16	926.522
2013	12	27	17	951.402
2013	12	27	18	1,028.128
2013	12	27	19	1,012.046
2013	12	27	20	990.165
2013	12	27	21	963.385
2013	12	27	22	921.579
2013	12	27	23	860.375
2013	12	27	24	791.527
2013	12	28	1	741.560
2013	12	28	2	702.506
2013	12	28	3	688.485
2013	12	28	4	674.703
2013	12	28	5	677.000
2013	12	28	6	693.079
2013	12	28	7	725.086
2013	12	28	8	749.723
2013	12	28	9	775.353
2013	12	28	10	815.124
2013	12	28	11	842.722
2013	12	28	12	852.964
2013	12	28	13	839.919
2013	12	28	14	822.755
2013	12	28	15	805.945
2013	12	28	16	793.845
2013	12	28	17	841.595
2013	12	28	18	935.194
2013	12	28	19	935.477
2013	12	28	20	920.097
2013	12	28	21	897.057
2013	12	28	22	859.962
2013	12	28	23	811.991
2013	12	28	24	750.063
2013	12	29	1	700.980
2013	12	29	2	667.003
2013	12	29	3	648.447
2013	12	29	4	639.208
2013	12	29	5	642.289
2013	12	29	6	646.343
2013	12	29	7	677.019
2013	12	29	8	707.314
2013	12	29	9	729.394
2013	12	29	10	760.575
2013	12	29	11	786.159
2013	12	29	12	810.699

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	29	13	819.971
2013	12	29	14	819.203
2013	12	29	15	826.303
2013	12	29	16	839.066
2013	12	29	17	888.154
2013	12	29	18	943.562
2013	12	29	19	937.043
2013	12	29	20	915.665
2013	12	29	21	892.850
2013	12	29	22	852.963
2013	12	29	23	797.813
2013	12	29	24	745.210
2013	12	30	1	703.515
2013	12	30	2	682.935
2013	12	30	3	677.710
2013	12	30	4	680.033
2013	12	30	5	700.537
2013	12	30	6	754.051
2013	12	30	7	828.130
2013	12	30	8	896.867
2013	12	30	9	917.285
2013	12	30	10	944.938
2013	12	30	11	971.975
2013	12	30	12	983.582
2013	12	30	13	971.223
2013	12	30	14	976.026
2013	12	30	15	967.990
2013	12	30	16	964.239
2013	12	30	17	996.085
2013	12	30	18	1,083.108
2013	12	30	19	1,080.429
2013	12	30	20	1,065.093
2013	12	30	21	1,029.013
2013	12	30	22	978.627
2013	12	30	23	897.756
2013	12	30	24	831.237
2013	12	31	1	779.997
2013	12	31	2	753.305
2013	12	31	3	736.658
2013	12	31	4	734.323
2013	12	31	5	741.437
2013	12	31	6	782.296
2013	12	31	7	839.015
2013	12	31	8	887.209
2013	12	31	9	907.367
2013	12	31	10	933.054
2013	12	31	11	948.561
2013	12	31	12	954.749
2013	12	31	13	952.817
2013	12	31	14	954.483

Year	Month	Day	HourEnding	RG&E System Load (MW)
2013	12	31	15	938.516
2013	12	31	16	940.937
2013	12	31	17	978.013
2013	12	31	18	1,067.721
2013	12	31	19	1,046.836
2013	12	31	20	1,004.753
2013	12	31	21	963.538
2013	12	31	22	919.306
2013	12	31	23	879.067
2013	12	31	24	834.866

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INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.5)

Request No.: GNP-15-210

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

RG&E Area Single-Line Diagrams

1) Provide a single line operating diagram of the existing Rochester Area transmission system including monitored and other pertinent facilities (notably including 34.5 kV and 11.5 kV circuits being upgraded in the GRTA) associated with the Fall 2015 updated Ginna Retirement Transmission Alternative (GRTA) Reliability Study.

2) Provide a single line operating diagram of the future anticipated Rochester Area transmission system including new facilities proposed for the GRTA, Station 80 upgrades and the Rochester Area Reinforcement Project (RARP).

Response:

Drawings are still in development. Available drawings are in the attached files:

- Attachment 1 - RGE Transmission System Map with RARP - CONFIDENTIAL
- Attachment 2 - RGE Transmission System Map Existing - CONFIDENTIAL
- Attachment 3 - R80-2-40FD-D-06101 SH 1 Rev.J.1 Single Line - CONFIDENTIAL
- Attachment 4 - R122-2-53FG-D--06104 REVC SINGLE LINE - CONFIDENTIAL

Please note: Attachments 1 through 4 are confidential and have been submitted pursuant to the terms and conditions of the Protective Order/Agreement in this proceeding.

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INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.6)

Request No.: GNP-15-211

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

Ratings of Existing 345/115 kV Transformers in Rochester Area

With respect to existing 345/115 kV transformers in the Rochester Area:

1) Verify – or update as applicable – the ratings (nameplates, and summer and winter Normal, LTE and STE thermal ratings) of these transformers as provided by RG&E on 10/6/2014 in its response to Information Request RARP-12-095 (ALJ-5) in Case 11-T-0534, and as duplicated below:

Rochester Area Existing 345/115 kV Transformer Ratings (in MW)								
Station	TB#	Nameplate	Summer			Winter		
			Normal	LTE	STE	Normal	LTE	STE
80	1	420	494	603	630	582	630	630
80	2	280	330	415	478	390	476	478
80	3	420	494	603	630	682	630	630
80	5	420	462	567	630	546	630	630
122	1	224	228	282	336	273	329	336
122	2	224	228	282	336	273	329	336
122	3	250	255	319	336	314	336	336

2) Verify that the above ratings are in MW, and if so, specify the respective summer and winter power factors assumed on the primary side of the transformer. Otherwise indicate the units in which they are rated (e.g. MVA).

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Response:

1) The ratings (nameplates, and summer and winter Normal, LTE and STE thermal ratings) of existing 345/115 kV transformers in the Rochester Area are:

Rochester Area Existing 345/115 kV Transformer Ratings (in MVA)								
Station	TB#	Nameplate	Summer			Winter		
			Normal	LTE	STE	Normal	LTE	STE
80	1	420	494	603	630	582	630	630
80	2	280	330	415	478	390	476	478
80	3	420	494	603	630	582	630	630
80	5	420	462	567	630	546	630	630
122	1	224	228	282	336	273	329	336
122	2	224	228	282	336	273	329	336
122	3	250	255	319	336	314	336	336

2) The above ratings are in MVA

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INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.7)

Request No.: GNP-15-212

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

Ratings of Future 345/115 kV Transformers in Rochester Area

With respect to planned or proposed new 345/115 kV transformers at Station 80, Station 122 and Station 255, provide the ratings (nameplates, and estimated summer and winter Normal, LTE and STE thermal ratings) for each, either in MW along with the respective power factor assumed, or in MVA.

Response:

RGE initially indicated that a spare transformer could be installed at Station 122 if needed to meet the schedule. The current schedule shows that three new transformers will likely be delivered in time such that the spare transformer will not be needed. The ratings for the new 345/115 kV transformers at station 122 are:

Rochester Area Existing 345/115 kV Transformer Ratings (in MVA)								
Station	TB#	Nameplate	Summer			Winter		
			Normal	LTE	STE	Normal	LTE	STE
122	4	448	527	643	675	620	672	705
122	5	448	527	643	675	620	672	705
122	6	448	527	643	675	620	672	705

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Should it be necessary to use the spare transformer instead, the ratings will be:

Rochester Area Existing 345/115 kV Transformer Ratings (in MVA)								
Station	TB#	Nameplate	Summer			Winter		
			Normal	LTE	STE	Normal	LTE	STE
122	4	420	494	603	630	582	630	630
122	5	448	527	643	675	620	672	705
122	6	448	527	643	675	620	672	705

The ratings for the new 345/115 kV transformers at station 255 will be:

Rochester Area Existing 345/115 kV Transformer Ratings (in MVA)								
Station	TB#	Nameplate	Summer			Winter		
			Normal	LTE	STE	Normal	LTE	STE
255	1	448	527	643	675	620	672	705
255	2	448	527	643	675	620	672	705

No new transformers are planned at Station 80.

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INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.8)

Request No.: GNP-15-213

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

Power-Flows for Fall 2015 GRTA Reliability Study Update
With regard to the Fall 2015 Ginna Retirement Transmission Alternative Reliability Study update, provide power flows output diagrams for the Rochester Area (with MW and MVAr flows indicated) for each of the cases described in the table below with applicable phase angle regulators (PARs) adjusted – as needed and to the extent feasible to reduce or eliminate thermal overloads. Identify each case with the respective Case ID as listed below.

Power Flows - GRTA Reliability Study Update (Fall 2015)						
Case ID	Condition	Specific Contingency or Contingencies*	RG&E Load (MW)	Ginna Status	GRTA & Station 80 Add'l Upgrades Status	RARP Status
A0	N-0 (All-Lines-In)	--	1,829	In	Out	Out
A1	N-1 Worst Case	Sta 122 345/115 kV TB#1				
A2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
B0	N-0 (All-Lines-In)	--	1,430	Out	Out	Out
B1	N-1 Worst Case	Sta 122 345/115 kV TB#1				
B2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
C0	N-0 (All-Lines-In)	--	1,829	Out	Out	Out
C1	N-1 Worst Case	Sta 122 345/115 kV TB#1				
C2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
D0	N-0 (All-Lines-In)	--	1,829	Out	Circuits 718, 735,	Out

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D1	N-1 Worst Case	Sta 122 345/115 kV TB#1			770 & 623 Upgrades Completed, but not Station 80 or Station 122 Upgrades	
D2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
E0	N-0 (All-Lines-In)	--	1,829	Out	In	Out
E1	N-1 Worst Case	Sta 122 345/115 kV TB#1				
E2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
F0	N-0 (All-Lines-In)	--	1,829	Out	In	In
F1	N-1 Worst Case	Sta 122 345/115 kV TB#1				
F2	N-1-1 Worst Case	Sta 122 345/115 kV TB#1 and TB #2				
* If an N-1 or N-1-1 contingency in a specific case results in more severe outcomes than the corresponding contingency listed above, indicate and describe the more severe contingency and its associated impact, but provide power-flows for the cases listed above.						

Response:

See attached files.

The more severe outcomes than presented in the power flows are stuck breaker N-1 contingencies resulting in loss of two elements for cases A1, B1, C1 and D1; and stuck breaker N-1-1 contingencies resulting in loss of three elements for cases A2, B2, C2, and D2. The associated impacts for cases A1, A2, B1, B2 and C2 are in the table below, and those for C1, D1 and D2 are in tables 5, 12 and 13 respectively of the Fall 2015 Ginna Retirement Transmission Alternative Reliability Study update.

Case ID	Condition	Specific Contingency or Contingencies*	RG&E Load (MW)	Associated impact
A1	N-1 Worst Case	Station 80 T5 and T2	1.829	Pittsford tap24 – Pannell 115kV bus (NG Trunk #24 at 110% LTE; violation begins at 1,560 MW RG&E load
A2	N-1-1 Worst Case	Ginna and stuck breaker at Station 122 resulting in loss of 345/115 kV TB#1 & TB #3	1.829	Station 122 transformer 345/115kV TB#2 at 148%LTE
B1	N-1 Worst Case	Station 122 345/115 kV TB#1 and TB#3	1.430	Station 122 345/115 kV TB#2 at 122.9%LTE
B2	N-1-1 Worst Case	Station 122 345/115 kV TB#1, TB#2 and TB #3 (stuck breaker)	1.430	Mortimer-Station 82 tie at 134.5%LTE; Mortimer –Station 89 (NG Trunk #25) at 110.9%LTE; Pittsford Tap23 – station 82 (NG

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				Trunk #23) at 105.6%LTE
C2	N-1-1 Worst Case	Station 122 345/115 kV TB#1, TB#2 and TB #3 (stuck breaker)	1,829	Mortimer-Station 82 tie at 139.4%LTE; Mortimer –Station 89 (NG Trunk #25) at 115.9%LTE; Pittsford Tap23 – station 82 (NG Trunk #23) at 107.2%LTE

Please note: Attachments 1 through 18 are confidential and have been submitted pursuant to the terms and conditions of the Protective Order/Agreement in this proceeding.

Attachment List:

Title	Case ID	Condition
Attachment 01	A0	N-0 (All-Lines-In)
Attachment 02	A1	N-1 Worst Case
Attachment 03	A2	N-1-1 Worst Case
Attachment 04	B0	N-0 (All-Lines-In)
Attachment 05	B1	N-1 Worst Case
Attachment 06	B2	N-1-1 Worst Case
Attachment 07	C0	N-0 (All-Lines-In)
Attachment 08	C1	N-1 Worst Case
Attachment 09	C2	N-1-1 Worst Case
Attachment 10	D0	N-0 (All-Lines-In)
Attachment 11	D1	N-1 Worst Case
Attachment 12	D2	N-1-1 Worst Case
Attachment 13	E0	N-0 (All-Lines-In)
Attachment 14	E1	N-1 Worst Case
Attachment 15	E2	N-1-1 Worst Case
Attachment 16	F0	N-0 (All-Lines-In)
Attachment 17	F1	N-1 Worst Case
Attachment 18	F2	N-1-1 Worst Case

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INFORMATION REQUEST

Requesting Party and No: Department of Public Service Staff (DPS-5.9)

Request No.: GNP-15-214

Date of Request: October 29, 2015

Response Due: November 12, 2015

Date of Reply: November 12, 2015

Respondent: Tim Lynch / Beatriz Alonso

Re: DPS Staff's Fifth Set of Information Requests

Question:

Disposition of Existing Station 122 Transformers

With respect to the existing 345/115 kV transformers (TB#1, TB#2 and TB#3) at Pannel Station 122:

1) Indicate the planned disposition of each (e.g., retain as spare, sell for re-use, salvage for scrap, other).

2) Comment on the electrical and physical feasibility of keeping two (or three) of the existing Station 122 345/115 kV transformers in service (or on site in standby mode) to reduce or eliminate reliability violations (that would occur without Ginna in service) and mitigate risks in the event some but not all of the GRTA and Station 80 upgrade work is completed by Spring of 2017. For instance, could Station 122 TB#1 and TB#2 remaining in service along with completion of the Station 80 upgrade work and installation of only TB#4 and TB#5 at Station 122 (without installation of TB#6) provide an acceptable solution?

Response:

1) RG&E plans to salvage for scrap Transformers 1T and 2T. These transformers have been in service for 40+ years each. RG&E is investigating keeping 3T (which was commissioned in 1999) as a spare on its current foundation or moving it to the foundation currently occupied by 1T once 1T is decommissioned. The 1T foundation has an oil containment system and is suitable to house 3T on-site as a spare.

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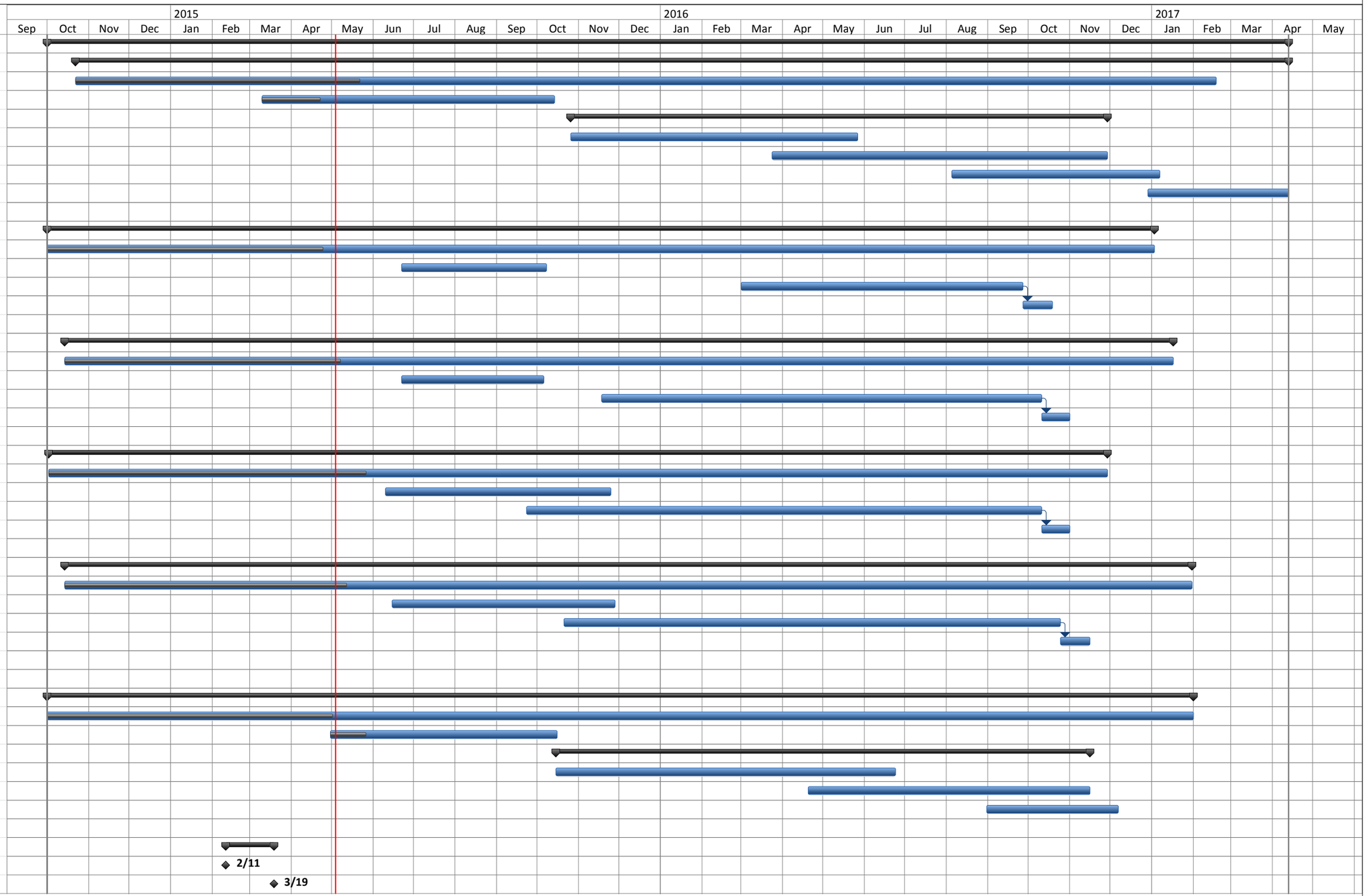
2) The intention is to keep the existing 115kV system energized and in service while testing and commissioning the new transformers 4T, 5T, and 6T. The individual 115kV circuits and capacitor bank will be cut over to the new 115kV GIS bus arrangement. Upon completion of the commissioning of the entire new 115kV GIS arrangement and new transformers, the existing transformers 1T and 2T will be decommissioned. Once circuit 925 is cut over to the new GIS, the existing transformer 3T will no longer be needed and will be preserved as a spare unit. It is presently a single source for line 925 and the GIS as configured has only future terminal positions meaning there is space for expansion, but the equipment would need to be specified, engineered and procured.

RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

ID	Task Name	% Complete
1	**GRTA**	**16%**
2	**Station 122**	**14%**
3	Engineering	25%
4	Permitting	20%
5	**Construction**	**0%**
6	In Ground	0%
7	Above Ground	0%
8	Commissioning	0%
9	Demo 115 AIS	0%
10		
11	**Circuit 623**	**18%**
12	Engineering	25%
13	Permitting / ROW	0%
14	Construction	0%
15	Commissioning	0%
16		
17	**Circuit 718**	**16%**
18	Engineering	25%
19	Permitting / ROW	0%
20	Construction	0%
21	Commissioning	0%
22		
23	**Circuit 735**	**17%**
24	Engineering	30%
25	Permitting / ROW	0%
26	Construction	0%
27	Commissioning	0%
28		
29	**Circuit 770**	**15%**
30	Engineering	25%
31	Permitting / ROW	0%
32	Construction	0%
33	Commissioning	0%
34		
35		
36	**Station 80 (5th Bay)**	**15%**
37	Engineering	25%
38	Permitting	15%
39	**Construction**	**0%**
40	In Ground	0%
41	Above Ground	0%
42	Commissioning	0%
43		
44	**Regulatory Meetings**	**100%**
45	DPS Staff	100%
46	DEC/DAM Staff	100%



Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPS-DEC (APRIL 2015).mpp
Printed Date: Mon 5/4/15

RG&E

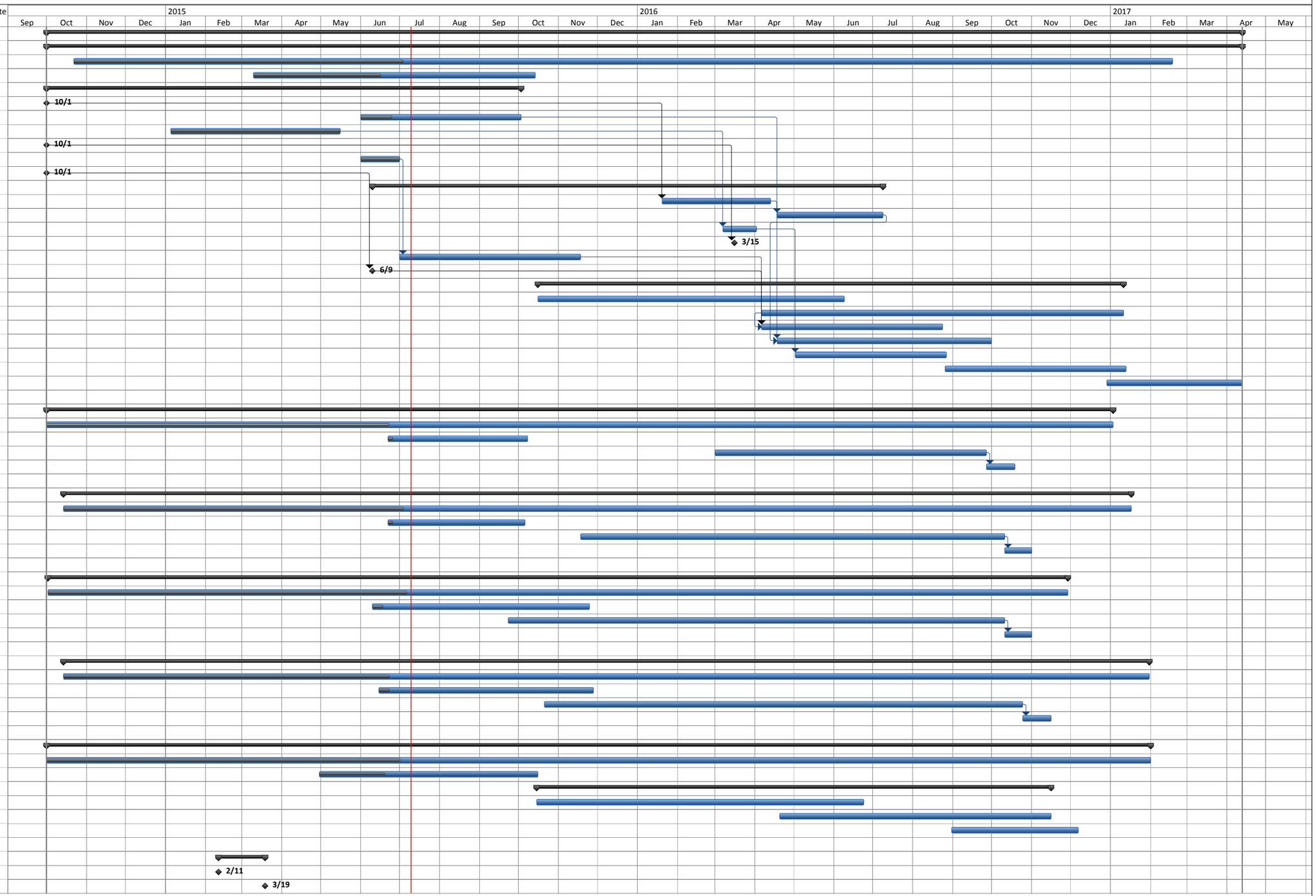
RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

ID	Task Name	% Complete
1	**GRTA**	**18%**
2	**Station 122**	**16%**
3	Engineering	27%
4	Permitting	25%
5	**Construction**	**0%**
6	In Ground	0%
7	Above Ground	0%
8	Commissioning	0%
9	Demo 115 AIS	0%
10		
11	**Circuit 623**	**22%**
12	Engineering	30%
13	Permitting / ROW	5%
14	Construction	0%
15	Commissioning	0%
16		
17	**Circuit 718**	**20%**
18	Engineering	30%
19	Permitting / ROW	5%
20	Construction	0%
21	Commissioning	0%
22		
23	**Circuit 735**	**19%**
24	Engineering	32%
25	Permitting / ROW	5%
26	Construction	0%
27	Commissioning	0%
28		
29	**Circuit 770**	**17%**
30	Engineering	28%
31	Permitting / ROW	5%
32	Construction	0%
33	Commissioning	0%
34		
35		
36	**Station 80 (5th Bay)**	**19%**
37	Engineering	30%
38	Permitting	25%
39	**Construction**	**0%**
40	In Ground	0%
41	Above Ground	0%
42	Commissioning	0%
43		
44	**Regulatory Meetings**	**100%**
45	DPS Staff	100%
46	DEC/DAM Staff	100%

Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPS-DEC (MAY 2015).mpp
Printed Date: Sun 5/31/15

RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

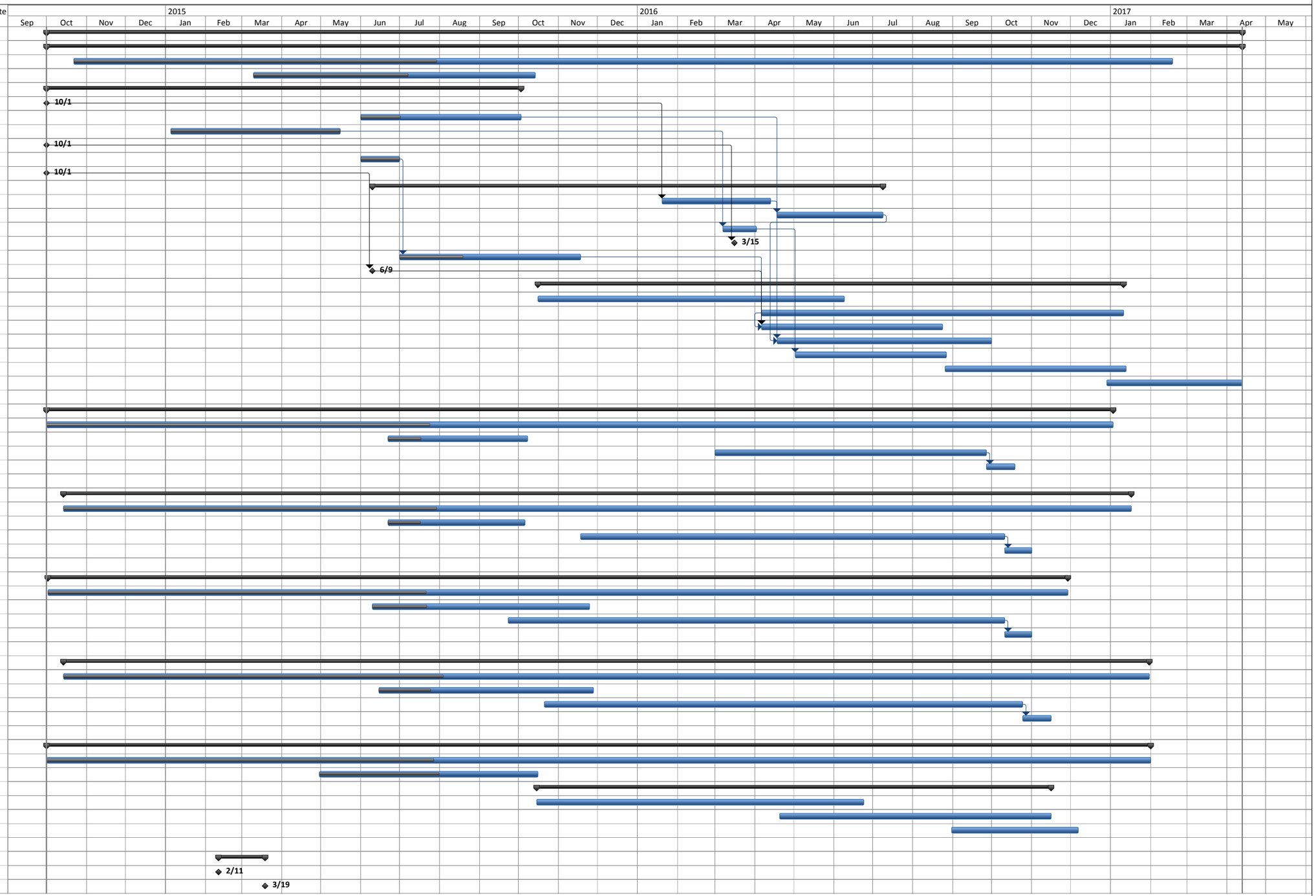
ID	Task Name	% Complete
1	GRTA	20%
2	**Station 122**	**19%**
3	Engineering	30%
4	Permitting	45%
5	**Procurement of Long-lead Equipment**	**65%**
6	Power Transformers T4 and T5	100%
7	Power Transformer T6	20%
8	115kV GIS (EPC)	100%
9	345kV Circuit Breakers (CB)	0%
10	115kV Circuit Breakers (CB)	100%
11	345kV and 115kV Switches	0%
12	**Delivery of Long-lead Equipment**	**0%**
13	Power Transformers T4 and T5	0%
14	Power Transformer T6	0%
15	115kV GIS (EPC)	0%
16	345kV CB	0%
17	115kV CB	0%
18	115kV and 345kV Switches	100%
19	**Construction**	**0%**
20	In Ground	0%
21	Above Ground	0%
22	Install Outdoor Equipment	0%
23	Install Power Transformers (T4, T5, T6)	0%
24	Install 115kV GIS (EPC)	0%
25	Commissioning	0%
26	Demo 115 AIS	0%
27		
28	**Circuit 623**	**23%**
29	Engineering	32%
30	Permitting / ROW	5%
31	Construction	0%
32	Commissioning	0%
33		
34	**Circuit 718**	**21%**
35	Engineering	32%
36	Permitting / ROW	5%
37	Construction	0%
38	Commissioning	0%
39		
40	**Circuit 735**	**21%**
41	Engineering	35%
42	Permitting / ROW	5%
43	Construction	0%
44	Commissioning	0%
45		
46	**Circuit 770**	**19%**
47	Engineering	30%
48	Permitting / ROW	5%
49	Construction	0%
50	Commissioning	0%
51		
52	Station 80 (5th Bay)	20%
53	Engineering	32%
54	Permitting	30%
55	**Construction**	**0%**
56	In Ground	0%
57	Above Ground	0%
58	Commissioning	0%
59		
60	Regulatory Meetings	100%
61	DPS Staff	100%
62	DEC/DAM Staff	100%



Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPS-DEC (JUNE 2015 - REV A).mpp
Printed Date: Fri 7/10/15

RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

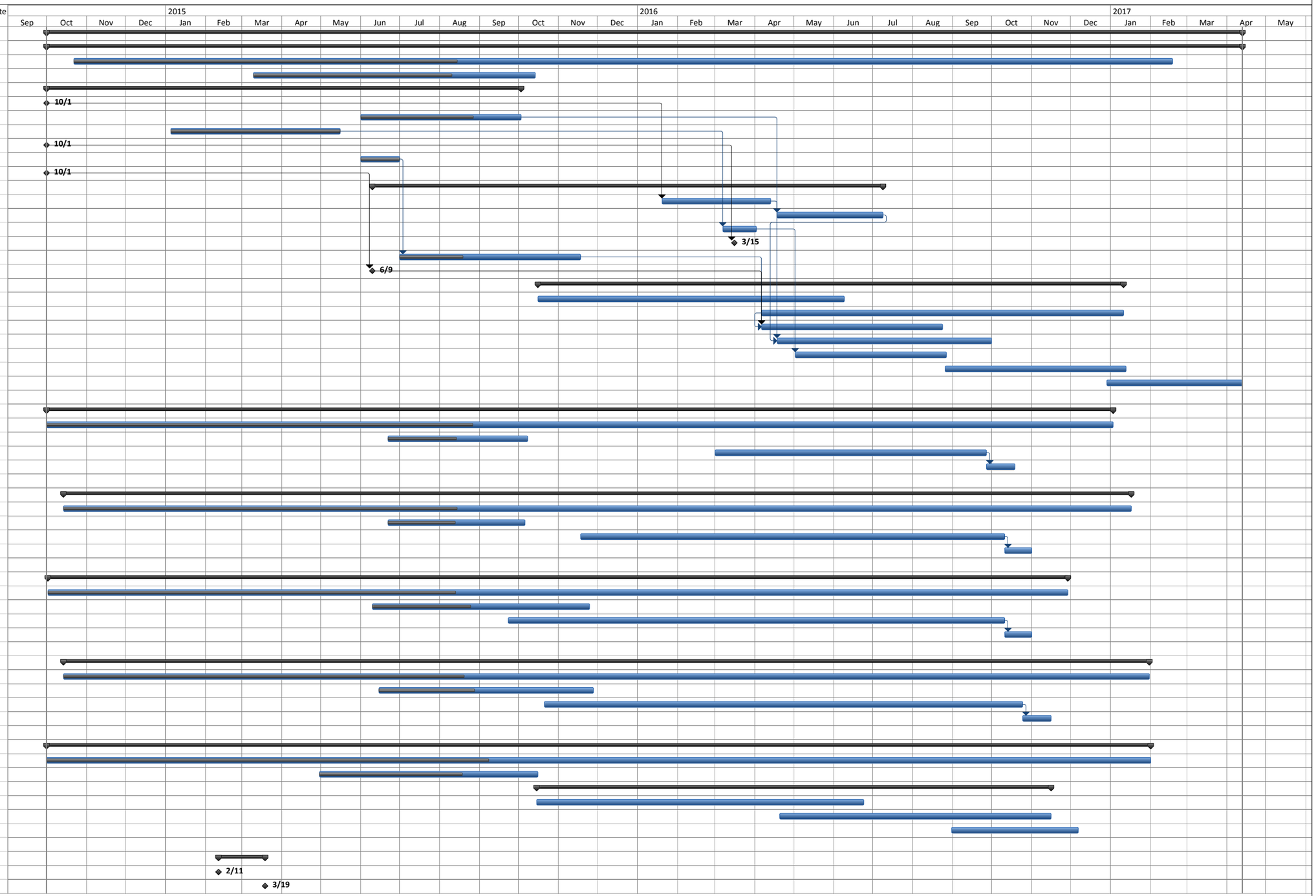
ID	Task Name	% Complete
1	GRTA	24%
2	**Station 122**	**22%**
3	Engineering	33%
4	Permitting	55%
5	**Procurement of Long-lead Equipment**	**67%**
6	Power Transformers T4 and T5	100%
7	Power Transformer T6	25%
8	115kV GIS (EPC)	100%
9	345kV Circuit Breakers (CB)	0%
10	115kV Circuit Breakers (CB)	100%
11	345kV and 115kV Switches	0%
12	**Delivery of Long-lead Equipment**	**15%**
13	Power Transformers T4 and T5	0%
14	Power Transformer T6	0%
15	115kV GIS (EPC)	0%
16	345kV CB	0%
17	115kV CB	35%
18	115kV and 345kV Switches	100%
19	**Construction**	**0%**
20	In Ground	0%
21	Above Ground	0%
22	Install Outdoor Equipment	0%
23	Install Power Transformers (T4, T5, T6)	0%
24	Install 115kV GIS (EPC)	0%
25	Commissioning	0%
26	Demo 115 AIS	0%
27		
28	**Circuit 623**	**28%**
29	Engineering	36%
30	Permitting / ROW	25%
31	Construction	0%
32	Commissioning	0%
33		
34	**Circuit 718**	**25%**
35	Engineering	35%
36	Permitting / ROW	25%
37	Construction	0%
38	Commissioning	0%
39		
40	**Circuit 735**	**25%**
41	Engineering	37%
42	Permitting / ROW	25%
43	Construction	0%
44	Commissioning	0%
45		
46	**Circuit 770**	**24%**
47	Engineering	35%
48	Permitting / ROW	25%
49	Construction	0%
50	Commissioning	0%
51		
52	Station 80 (5th Bay)	25%
53	Engineering	35%
54	Permitting	55%
55	**Construction**	**0%**
56	In Ground	0%
57	Above Ground	0%
58	Commissioning	0%
59		
60	Regulatory Meetings	100%
61	DPS Staff	100%
62	DEC/DAM Staff	100%



Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPS-DEC (JULY 2015).mpp
Printed Date: Wed 8/5/15

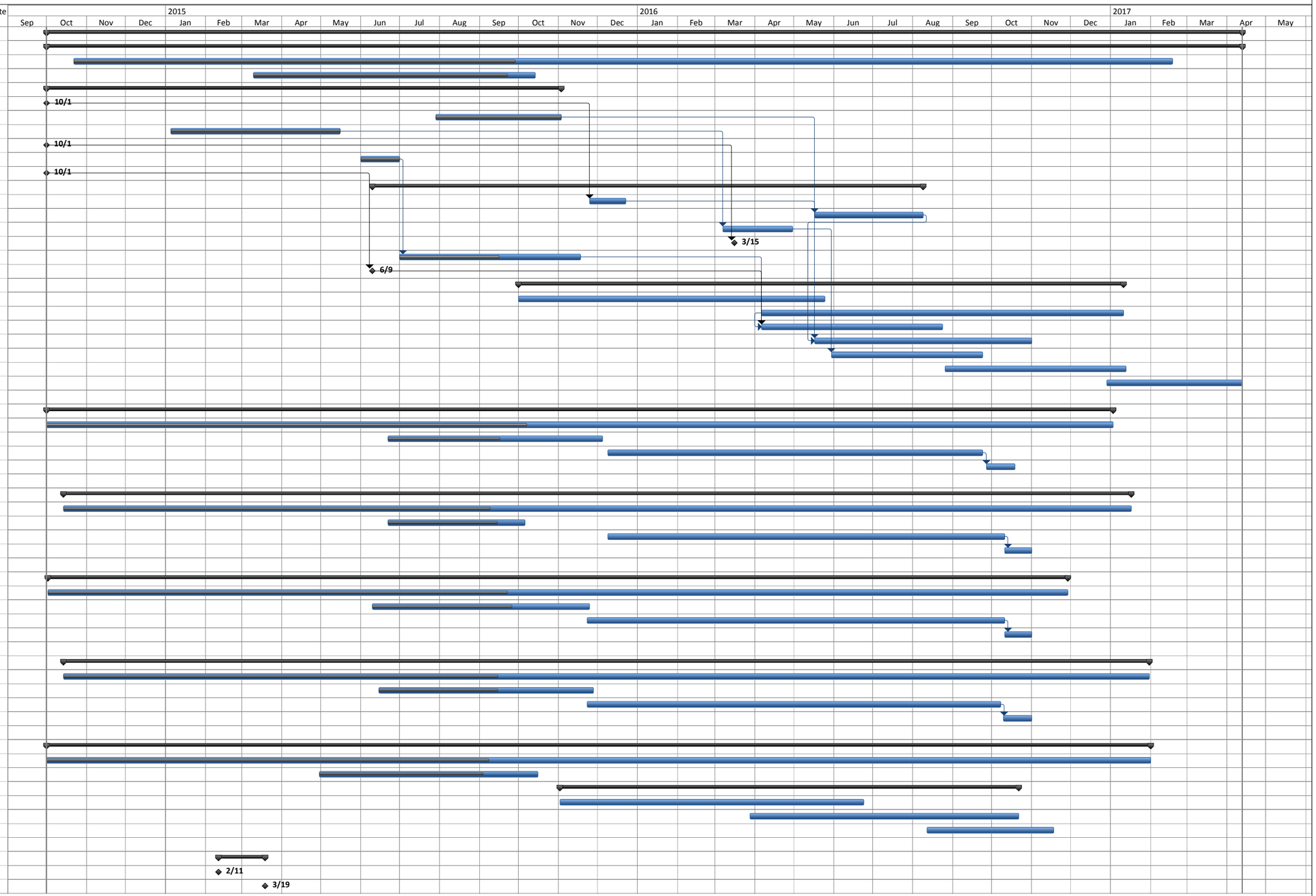
RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

ID	Task Name	% Complete
1	GRTA	28%
2	**Station 122**	**26%**
3	Engineering	35%
4	Permitting	70%
5	**Procurement of Long-lead Equipment**	**87%**
6	Power Transformers T4 and T5	100%
7	Power Transformer T6	70%
8	115kV GIS (EPC)	100%
9	345kV Circuit Breakers (CB)	100%
10	115kV Circuit Breakers (CB)	100%
11	345kV and 115kV Switches	100%
12	**Delivery of Long-lead Equipment**	**15%**
13	Power Transformers T4 and T5	0%
14	Power Transformer T6	0%
15	115kV GIS (EPC)	0%
16	345kV CB	0%
17	115kV CB	35%
18	115kV and 345kV Switches	100%
19	**Construction**	**0%**
20	In Ground	0%
21	Above Ground	0%
22	Install Outdoor Equipment	0%
23	Install Power Transformers (T4, T5, T6)	0%
24	Install 115kV GIS (EPC)	0%
25	Commissioning	0%
26	Demo 115 AIS	0%
27		
28	**Circuit 623**	**33%**
29	Engineering	40%
30	Permitting / ROW	50%
31	Construction	0%
32	Commissioning	0%
33		
34	**Circuit 718**	**28%**
35	Engineering	37%
36	Permitting / ROW	50%
37	Construction	0%
38	Commissioning	0%
39		
40	**Circuit 735**	**29%**
41	Engineering	40%
42	Permitting / ROW	45%
43	Construction	0%
44	Commissioning	0%
45		
46	**Circuit 770**	**28%**
47	Engineering	37%
48	Permitting / ROW	45%
49	Construction	0%
50	Commissioning	0%
51		
52	Station 80 (5th Bay)	29%
53	Engineering	40%
54	Permitting	65%
55	**Construction**	**0%**
56	In Ground	0%
57	Above Ground	0%
58	Commissioning	0%
59		
60	Regulatory Meetings	100%
61	DPS Staff	100%
62	DEC/DAM Staff	100%



RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

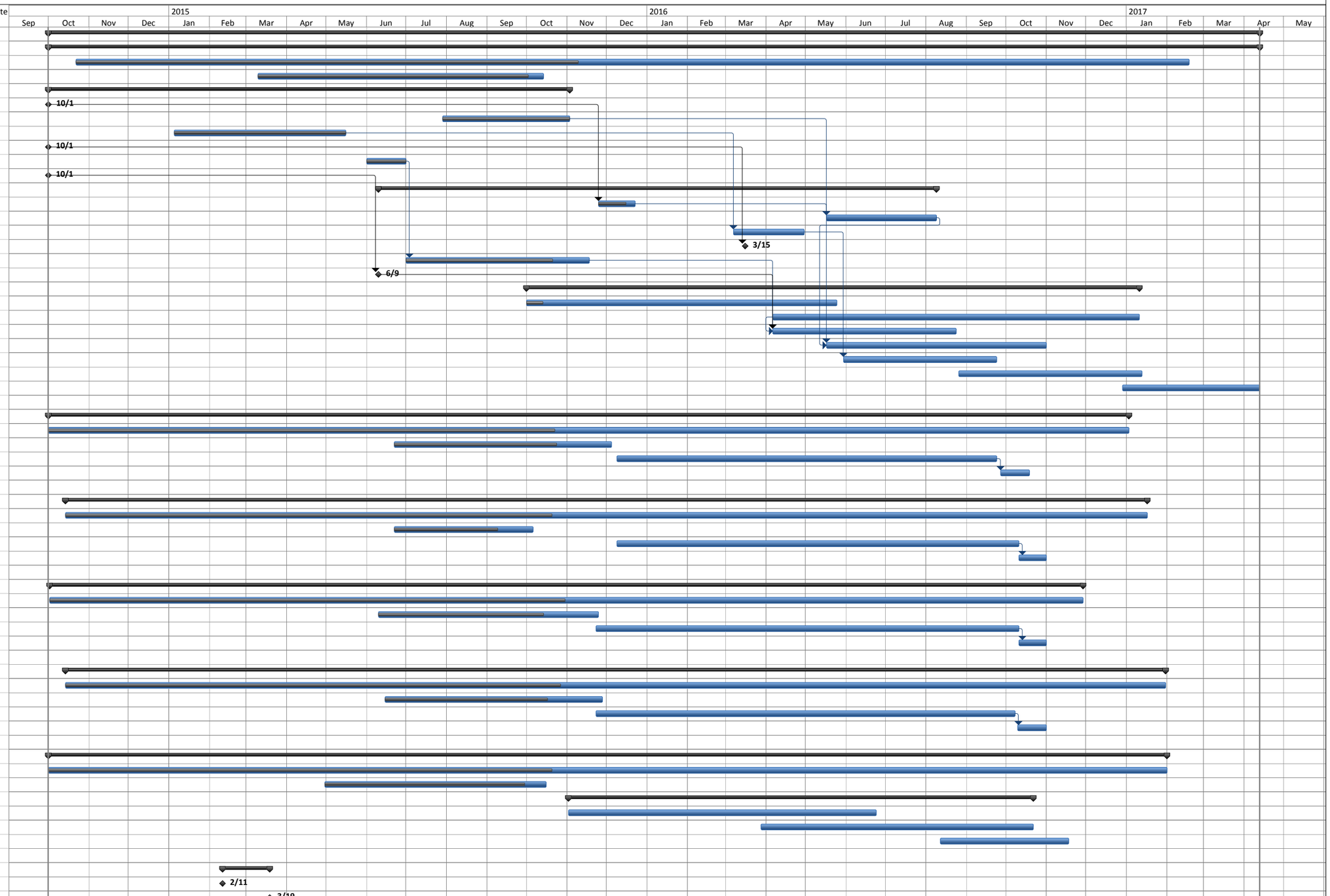
ID	Task Name	% Complete
1	GRTA	33%
2	**Station 122**	**31%**
3	Engineering	40%
4	Permitting	90%
5	**Procurement of Long-lead Equipment**	**100%**
6	Power Transformers T4 and T5	100%
7	Power Transformer T6	100%
8	115kV GIS (EPC)	100%
9	345kV Circuit Breakers (CB)	100%
10	115kV Circuit Breakers (CB)	100%
11	345kV and 115kV Switches	100%
12	**Delivery of Long-lead Equipment**	**25%**
13	Power Transformers T4 and T5	0%
14	Power Transformer T6	0%
15	115kV GIS (EPC)	0%
16	345kV CB	0%
17	115kV CB	55%
18	115kV and 345kV Switches	100%
19	**Construction**	**0%**
20	In Ground	0%
21	Above Ground	0%
22	Install Outdoor Equipment	0%
23	Install Power Transformers (T4, T5, T6)	0%
24	Install 115kV GIS (EPC)	0%
25	Commissioning	0%
26	Demo 115 AIS	0%
27		
28	**Circuit 623**	**35%**
29	Engineering	45%
30	Permitting / ROW	52%
31	Construction	0%
32	Commissioning	0%
33		
34	**Circuit 718**	**33%**
35	Engineering	40%
36	Permitting / ROW	80%
37	Construction	0%
38	Commissioning	0%
39		
40	**Circuit 735**	**36%**
41	Engineering	45%
42	Permitting / ROW	65%
43	Construction	0%
44	Commissioning	0%
45		
46	**Circuit 770**	**32%**
47	Engineering	40%
48	Permitting / ROW	55%
49	Construction	0%
50	Commissioning	0%
51		
52	Station 80 (5th Bay)	30%
53	Engineering	40%
54	Permitting	75%
55	**Construction**	**0%**
56	In Ground	0%
57	Above Ground	0%
58	Commissioning	0%
59		
60	Regulatory Meetings	100%
61	DPS Staff	100%
62	DEC/DAM Staff	100%



Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPSWed 10/7/15EC (SEPTEMBER 2015).mpp
Printed Date: Wed 10/7/15

RG&E / Ginna Retirement Transmission Alternative
Monthly Gantt Schedule for DPS/DEC

ID	Task Name	% Complete
1	GRTA	37%
2	**Station 122**	**35%**
3	Engineering	45%
4	Permitting	95%
5	**Procurement of Long-lead Equipment**	**100%**
6	Power Transformers T4 and T5	100%
7	Power Transformer T6	100%
8	115kV GIS (EPC)	100%
9	345kV Circuit Breakers (CB)	100%
10	115kV Circuit Breakers (CB)	100%
11	345kV and 115kV Switches	100%
12	**Delivery of Long-lead Equipment**	**43%**
13	Power Transformers T4 and T5	75%
14	Power Transformer T6	0%
15	115kV GIS (EPC)	0%
16	345kV CB	0%
17	115kV CB	80%
18	115kV and 345kV Switches	100%
19	**Construction**	**1%**
20	In Ground	5%
21	Above Ground	0%
22	Install Outdoor Equipment	0%
23	Install Power Transformers (T4, T5, T6)	0%
24	Install 115kV GIS (EPC)	0%
25	Commissioning	0%
26	Demo 115 AIS	0%
27		
28	**Circuit 623**	**39%**
29	Engineering	47%
30	Permitting / ROW	75%
31	Construction	0%
32	Commissioning	0%
33		
34	**Circuit 718**	**36%**
35	Engineering	45%
36	Permitting / ROW	75%
37	Construction	0%
38	Commissioning	0%
39		
40	**Circuit 735**	**40%**
41	Engineering	50%
42	Permitting / ROW	75%
43	Construction	0%
44	Commissioning	0%
45		
46	**Circuit 770**	**37%**
47	Engineering	45%
48	Permitting / ROW	75%
49	Construction	0%
50	Commissioning	0%
51		
52	Station 80 (5th Bay)	34%
53	Engineering	45%
54	Permitting	90%
55	**Construction**	**0%**
56	In Ground	0%
57	Above Ground	0%
58	Commissioning	0%
59		
60	Regulatory Meetings	100%
61	DPS Staff (Initial Call, plus monthly updates)	100%
62	DEC/DAM Staff	100%



Prepared: Vazquez/Murphy
File Name: GRTA & ST080 5th Bay - Monthly Schedule for DPSThu 11/5/15EC (OCTOBER 2015).mpp
Printed Date: Thu 11/5/15