



**Assessment of Cold Weather Event Operations in New England,
Appendix H of Market Rule 1, during Winter 2004–2005**

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April 29, 2005



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Assessment of Cold Weather Event Operations in New England, Appendix H of Market Rule 1, during Winter 2004–2005

I. Executive Summary

This report assesses the effectiveness of *Cold Weather Event Operations*, Appendix H of Market Rule 1 (Appendix H) during winter 2004–2005.^{1,2} Appendix H prescribes the formal processes that ISO New England (the ISO), owners of gas-fired generation units, and the natural gas industry follow to improve the ISO’s ability to forecast and operate during periods of extremely cold weather. The ISO assessed how Appendix H procedures performed during three periods characterized by unusually cold weather, one in December 2004 and two in January 2005. For the assessment, the ISO reviewed weather and operable capacity conditions and analyzed prices in the electricity and fuels markets during these periods. The assessment shows that market and system conditions improved, but because winter weather in 2004–2005 was less extreme than the weather that occurred during the cold snap of January 14–16, 2004 (January 2004 Cold Snap), it was not possible to distinguish between the effects of the procedures and the effects of less severe weather. In addition to the results of the analyses, this report includes preliminary recommendations on the implementation of Appendix H.

¹ Market Rule 1 is located at Section III of the ISO New England Transmission, Markets, and Services Tariff (Tariff). The document is available at: http://www.iso-ne.com/smd/market_rule_1_and_iso_new_england_manuals/Market_Rule_1_And_Appendices/.

² Appendix H became effective March 2, 2005, pending further review by FERC, and subject to refund and settlement/hearing procedures. Appendix H replaced Operating Procedure No. 20 (OP 20), which was approved by the New England Power Pool (NEPOOL) Participants Committee on November 5, 2004, and was in effect from that time until March 2, 2005.

Two of the unusually cold weather periods this winter—December 17–20, 2004, and January 27, 2005—did not trigger the scheduling actions of Appendix H. During each of these periods, the capacity margin, measured in megawatts (MW), remained positive, and the markets functioned as expected without the use of Appendix H. However, the improved the coordination and exchange of information with gas pipeline operators may have been enhanced operations. The December period highlights the sensitivity of the triggers in Appendix H to errors in the weather forecast.

The onset of cold weather during another period, January 18–22, 2005, led the ISO, on January 19, to declare a Cold Weather Watch³ for January 21. On January 20, prompted by projected capacity losses, the ISO upgraded the Watch to a Cold Weather Warning. These Appendix H declarations of Cold Weather Conditions triggered a number of ISO actions. These actions resulted in the cancellation of existing outages requested for reasons unrelated to the physical condition of a generating unit (i.e., economic outages, as determined by the ISO per Operating Procedure No. 5, *Generation Maintenance and Outage Scheduling*) (OP 5),⁴ the automatic denial of new applications requesting economic outages, and a request that generating units with dual-fuel capability prepare for conversion to secondary fuels. The capacity margins remained positive throughout the mid-January 2005 cold period, despite a number of constraints and restrictions issued by the regional gas pipeline operators. The recall of units on economic outages and their subsequent return to service contributed to this positive reserve margin.

³ Capitalized terms have the means ascribed to them in the Tariff and are defined below in Section III.

⁴ OP 5 is available at http://www.iso-ne.com/smd/operating_procedures/.

No Cold Weather Events were declared, and the associated special scheduling procedures for gas-fired units were not needed.

The analysis of the application of Appendix H procedures in December 2004 and January 2005 suggests that the classification of Cold Weather Conditions is reasonable, and the resulting actions worked to improve the reliability of the bulk power system. It appears that additional actions were not needed to ensure system reliability. Since special scheduling procedures were not required, natural gas-fired units were committed under standard market rules. The quantities of out-of-merit generation and the resultant uplift and Locational Marginal Price (LMP) distortion were substantially reduced relative to levels experienced during the January 2004 Cold Snap. Based on the implementation and use of Appendix H, the ISO has the following recommendations for further improving the performance of the New England electricity markets during cold weather:

- The ISO should work with the regional natural gas pipeline companies to unify and streamline the gas industry's electronic bulletin board (EBB) information and the timely posting of this information to better serve the needs of system reliability.
- When canceling or denying the economic outage of a gas-fired generating unit, the forecast operator should inquire about the unit's ability to procure gas. This will allow the ISO to better assess the availability of the unit.
- The ISO should improve its understanding of the uncertainty surrounding each day's weather forecast and, as appropriate, incorporate these forecast uncertainty estimates in Appendix H definitions of triggering events.
- The ISO should continue efforts to increase real-time offer flexibility to allow gas units to better reflect intra-day gas costs in their offers.

Concurrent with the implementation of OP 20 and later Appendix H, the ISO continued to make other improvements that address the reliability of the bulk power

system during periods of cold weather. In its *Management Response to the Cold Snap Report*^{5, 6} the ISO enumerated 48 specific actions that should be taken to address or implement the recommendations of the *Cold Snap Report*. Of these recommended measures, 39 actions were successfully completed, and 9 actions are ongoing.

II. Introduction

This report describes and assesses the effectiveness of OP 20, later filed as the Tariff's Market Rule 1, Appendix H, *Cold Weather Event Operations*, during the winter of 2004–2005. These procedures were developed as a short-term remedy in response to observations of system and market operations made during the January 2004 Cold Snap.

In 2004, the ISO led an extensive stakeholder process that resulted in the development and implementation of new operating procedures and market improvements prior to winter 2004–2005. These stakeholder meetings included NEPOOL participants, natural gas industry representatives, and state policy makers and regulators. A new Cold Snap Task Force (CSTF) was formed to work with the existing Fuel Diversity Working Group (FDWG) and the Standing Technical Committees in NEPOOL. The CSTF reviewed existing market rules and operating procedures to find short-term remedial

⁵ ISO New England's *Management Response to the October 12, 2004, Publication, Final Report on Electricity Supply Conditions in New England during the January 14–16, 2004 "Cold Snap"* is available at: http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/.

⁶ The *Final Report on Electricity Supply Conditions in New England during the January 14–16, 2004 Cold Snap* is available at: http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/.

improvements to the procedures and address some of the recommendations identified within the *January 2004 Cold Snap Report*.

At the November 5, 2004, meeting of the NEPOOL Participants Committee, the ISO offered to provide an analysis of cold-weather operations during the upcoming winter. The Participants Committee adopted a resolution that the ISO file with the Commission a report by May 1, 2005.⁷

The response to the events of January 2004 resulted in the development of a new OP 20 Cold Weather Operating Procedure and associated changes to market manuals, which were supported by a large majority of NEPOOL participants. The primary features of this new procedure were as follows:

- Improve the availability of information about natural gas supply and transportation for use by the ISO operations personnel.
- Improve the information provided to regional market participants regarding potential Cold Weather Events and an assessment of power-system conditions during those events.
- In extreme cases, shift the Day-Ahead Energy Market timeline to allow for early commitments of natural gas generators in anticipation of possible natural gas supply or transportation constraints and operable capacity shortages on the bulk power system.

On December 7, 2004, American National Power (ANP) filed a complaint with the Federal Energy Regulatory Commission (FERC) regarding OP 20. By order dated

⁷The full resolution is: *a requirement for the ISO to file with the Commission a report by May 1, 2005 assessing the effectiveness of the cold weather scheduling procedures, with such a report including but not limited to the assessment of the effectiveness of OP 20 to identify the appropriate days and events for use of the special scheduling procedures, the quantity of megawatts and units committed prior to the Day-Ahead Market as a result of the exercise of OP 20, and the ability of price setting rules to reveal in the LMP the cost of all generation needed for reliability.*

January 21, 2005, FERC rejected several arguments put forth in the complaint but directed the ISO to file OP 20 as part of its Tariff.⁸ The Commission allowed OP 20 to remain in effect pending a ruling on the ISO's compliance filing. On January 28, 2005, the ISO filed the provisions of OP 20 as Appendix H to Market Rule 1 of the Tariff. On March 2, 2005, FERC accepted Appendix H for filing, making it effective as of that date and set certain limited issues for settlement/hearing procedures.⁹ FERC directed that hearing to be held in abeyance, while all parties explored settlement options. This process is ongoing. Since that time, the ISO has appended OP 20 to the market rules as Appendix H.

This report is intended to meet the requirements of the resolution adopted by the NEPOOL Participants Committee during its November 5, 2004, meeting. Section III of this report discusses the background of OP 20 and reviews Appendix H as implemented by the ISO. It defines Cold Weather Conditions, and it describes the triggers for classifying the days that experience these conditions and the actions the ISO takes based on these classifications. The section also describes the typical weekly updates that take place between the ISO and regional gas pipelines.

Case studies of the three winter 2004–2005 cold-weather periods are presented in Section IV to Section VI, two in detail and one more briefly. Section IV examines a cold-weather period in December 2004 when, despite an abrupt and unexpected change in weather, the capacity margin remained positive. The section explains how the triggering

⁸ *ANP Funding I. v. ISO New England, et al.*, 110 FERC ¶ 61,040 (2005).

⁹ *ISO New England, et al.*, 110 FERC ¶ 61,202 (2005).

criteria appropriately did not activate Appendix H during that period and examines the resulting wholesale electricity and fuels prices.

January 2005 experienced colder conditions than the December 2004 period, which triggered the use of Appendix H. Section V examines the period in January that contained the day for which the ISO declared both a Cold Weather Watch and then a Cold Weather Warning. This section reviews the period's sequence of operating events and evaluates the performance of Appendix H. The section also contrasts the behavior of gas prices with those of liquid fuels and highlights the importance of dual-fuel capabilities. Section VI describes a third period of cold weather in late January 2005 when Appendix H was not triggered.

Section VII provides conclusions and recommendations to further improve Appendix H. Three appendices provide the following information:

- Appendix A—an update of the status of the actions identified within ISO New England's *Management Response to the Cold Snap Report*
- Appendix B—details of events in the regional natural gas market
- Appendix C—the ISO market rule changes and dual-fuel capability performance during the report period

The Cold Weather Event procedures are referred to as Appendix H procedures throughout the remainder of this document.

III. Review of Appendix H

The *Cold Snap Report* made more than 20 recommendations for improving market and system operations during periods of cold weather. Some of the more important recommendations centered on “improving the ISO’s communications with the natural gas pipelines” and “supporting the dual-fuel capability of gas units.” Another important recommendation was that the ISO should investigate enhanced coordination of gas and electric trading to be effected by synchronizing the respective trading deadlines. The *Cold Snap Report* further noted that “such timing might better enable day-ahead gas purchases and transportation nominations to ensure maximum gas availability in real-time.”

The *ISO Management Response to the Cold Snap Report* addressed each of these recommendations. This report stated that “during the winter of 2004–2005, each gas-sector member of the Electric/Gas Operations Committee (EGOC) will participate in weekly operational look-ahead meetings with the ISO to forecast the occurrence of future cold-weather events.”^{10, 11} The *Management Response* noted the ongoing work to assess and inventory the capabilities of dual-fuel units and to communicate with regulators to enhance these capabilities during periods of cold weather.¹² The *Management Response*

¹⁰ The ISO and representatives of the regional natural gas industry, through coordination with the Northeast Gas Association (NGA), created the Electric/Gas Operations Committee in the spring of 2004 to promote greater regional reliability of the two industries through education, understanding, communications, and coordination.

¹¹ This commitment was included in OP 20 and is an obligatory component of Appendix H.

¹² *Dual-Fuel Generating Capacity and Environmental Constraints Analysis Interim Report*, ESS Group Inc., April 1, 2005. The document is available at http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/8_Dual_Fuel_Interim_Report/.

also noted that the ISO would develop and propose procedures to improve the coordination of the natural gas and wholesale electric market timelines. These proposals led to the development and subsequent approval of Appendix H in November 2004. Appendix A includes information on the status of the recommended action steps.

Appendix H provides specific enhancements to the ISO's routine operating procedures. One enhancement is the identification of forecast periods when system operations might be affected by cold-weather conditions. Every day by 11:00 a.m., the ISO produces weather and operable capacity-margin (capacity-margin)¹³ seven-day forecasts.¹⁴ The expected number of unit outages included in the capacity-margin forecast increases as temperature falls, reflecting both gas availability and weather-related forced-outage risks. For each day of a capacity-margin forecast, the forecast determines which Appendix H condition exists, as follows:

- No Cold Weather Conditions exist¹⁵—default condition for days when the results of the weather and capacity condition analyses do not warrant a Cold Weather Condition categorization
- Cold Weather Watch—declared for days that have Cold Weather Conditions and a forecast capacity margin for the peak hour that is equal to or above 1,000 MW

¹³ Operable Capacity Margin = (Total Available Capacity) – (Peak Load) – (Operating Reserve Requirement). Total Available Capacity = (Installed Generating Capacity) + (Capacity Additions of (Economic Maximum Limits in excess of Seasonal Claimed Capacity) + (Pre-OP4 Dispatchable Loads) – (Outages and Reductions) – (Generation Unavailable due to Start Time) – (Capacity Deliveries). The daily operable capacity (OpCap) analysis is available at: http://www.iso-ne.com/daily_opcap_analysis/.

The ISO Morning Report is available at: http://www.iso-ne.com/smd/operations_forecasting/morning_report_external.html.

¹⁴ Here and elsewhere in the report, the seven-day forecast means the current-day and subsequent six-day forecast.

¹⁵ See Section III.B, below, for rigorous definition of Cold Weather Conditions.

- Cold Weather Warning—declared for days that have Cold Weather Conditions and a forecast capacity margin for the peak hour that is positive and less than 1,000 MW
- Cold Weather Event—declared for days that have Cold Weather Conditions and a forecast capacity margin for the peak hour that is equal to or less than zero (deficient)

During the winter of 2004–2005, no Cold Weather Events occurred. However, the ISO declared both a Cold Weather Watch and a Cold Weather Warning during this time. This section explains the procedures for classifying Cold Weather Conditions, describes how the classifications trigger appropriate responses, and reviews the actions that resulted from these two particular conditions. The section also describes the typical weekly coordination that took place between the ISO and regional gas pipeline companies during the winter season.

A. Coordination with Gas Pipelines

Appendix H requires the ISO to confer with natural gas pipeline companies during the Winter Capability Period¹⁶ to review pipeline-transmission conditions for the coming week and to discuss weather and temperature forecasts, anticipated demand, and any notices posted by pipeline operators.¹⁷ During the Winter Capability Period, the weekly discussions between the ISO and regional natural gas pipeline companies typically take place on Thursdays, either via electronic mail or telephone; the discussions

¹⁶ ISO OP 14, *Technical Requirements for Generation, Dispatchable, and Interruptible Loads*, defines the Winter Capability Period as being from October 1 to May 31 of the following year.

¹⁷ Tariff Section 111.H.3.1.1

may be held more frequently if conditions warrant. For the winter of 2004–2005, these communications began on November 18, 2004, and continued through March 31, 2005.¹⁸

Gas-sector participation includes representatives from the following companies:

- Duke Energy—Algonquin Gas Transmission System (AGTS), Maritimes & Northeast Pipeline (M & N), and Texas Eastern Transmission Company (TETCO) pipelines
- El Paso Corp.—Tennessee Gas Pipeline (TGP)
- Iroquois Gas Transmission System (IGTS)
- Portland Natural Gas Transmission System (PNGTS)
- Distrigas of Massachusetts Corp. (DOMAC)—liquefied natural gas (LNG) company
- KeySpan Corp. (KEYSPAN)—local distribution company (LDC)

During their weekly communications, the ISO and gas industry representatives discuss real-time operations and projections for future-week operations and the following typical issues:

- weather forecast
 - impact on gas loads
 - impact on production areas (supply)
- maintenance
 - scheduled
 - unscheduled (forced outages)
- critical and non-critical notices/informational notices

¹⁸ At their November 10, 2004, meeting, EGO members initially agreed to support the weekly information exchanges through these dates only. Future discussions will be undertaken to assess the need to perform this function in the future.

- nature of constraint
- services impacted
- regions impacted
- expected duration

- gas-storage levels
 - storage volumes (percent full)
 - storage levels compared to the last-year and five-year average
 - restrictions on withdrawals or injections

- pipeline volumes
 - if the pipeline is running full, moderate, or empty
 - line pack and/or drafting issues

- upstream pipeline issues or constraints
 - TETCO feeding AGTS
 - TransCanada feeding IGTS and PNGTS

- gas supply
 - any weather-related or other disruptions (shut-in production)
 - Gulf of Mexico (AGTS and TGP)
 - Western Canadian Sedimentary Basin (IGTS and PNGTS)
 - Sable Island (M & N)

- LNG status
 - DOMAC status
 - satellite facilities (LNG and propane)

After these communications occur, the ISO compiles all relevant gas-sector information and distributes it to designated ISO staff. ISO Operations uses the applicable information during its weekly look-ahead conference call with the Northeast Power Coordinating Council (NPCC) of the North American Electric Reliability Council (NERC).¹⁹ A copy of the status report is also sent to the Northeast Gas Association.

¹⁹ The NPCC's mission is to promote the reliable and efficient operation of the interconnected bulk power systems in northeastern North America through the establishment of criteria; coordination of system planning, design and operations; and assessment of compliance with such criteria. When developing

In addition to these communications, the ISO regularly monitors the electronic bulletin boards of the regional gas pipelines. This alerts ISO personnel to operational warnings and problems and facilitates the verification of generator gas nominations.

B. Cold Weather Condition Triggers

The ISO uses the seven-day weather and capacity-margin forecasts to determine Appendix H conditions, relative to threshold values established in Appendix H. First, Appendix H requires a determination of Cold Weather Conditions, and it applies two measures to determine if Cold Weather Conditions exist. One measure is the hourly forecasted effective temperature T_{eff} :

$$T_{eff} = T_{db} - \frac{WS(65 - T_{db})}{100}, \quad (1)$$

where T_{db} is a dry-bulb temperature, measured in Fahrenheit,²⁰ and WS is wind speed, measured in miles per hour. The hourly effective temperature is an accurate predictor of energy consumption in a given hour.

reliability criteria, NPCC, to the extent possible, facilitates the attainment of fair, effective, and efficient competitive electric markets. See <http://www.npcc.org>.

NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. Since its formation in 1968, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure, and the mutual self-interest of those involved. See <http://www.nerc.com>.

²⁰ This dry-bulb temperature is the weighted average of the temperatures at different locations in New England, obtained from all the weather services contracted by the ISO for New England, as described in SOP-OUTSCH.0040.0010–Create Load Forecast (Attachment A). The document is available at http://www.iso-ne.com/smd/system_operating_procedures/SOP-OUTSCH.0040.0010.doc.

The second measure of weather used by Appendix H is the daily forecasted effective heating degree days (HDD_{eff}). HDD was originally developed for evaluating daily energy demand and consumption.²¹ The formula to calculate HDD_{eff} is as follows:

$$HDD_{eff} = 68 - \frac{T_{eff}^{\max} + T_{eff}^{\min}}{2}, \quad (2)$$

where T_{eff}^{\max} and T_{eff}^{\min} are the maximum and minimum forecasted hourly effective temperatures for a given day.

Cold Weather Conditions are announced based on the forecast values of T_{eff} and HDD_{eff} . Namely, a day is forecast to have Cold Weather Conditions if the following conditions are fulfilled simultaneously:

$$CWC \equiv \begin{cases} \bar{T}_{eff}^{on-peak} \leq 0 \\ HDD_{eff} \geq 65 \end{cases} \quad (3)$$

where $\bar{T}_{eff}^{on-peak}$ is the arithmetic average of on-peak T_{eff} values.²² If these conditions are not met, a day is categorized as not experiencing Cold Weather Conditions, and no further evaluation is required.

Each day that Cold Weather Conditions are expected, the ISO evaluates the seven-day capacity-margin forecast.²³ The expected capacity margin determines which

²¹ For a definition of HDD, see the glossary of Climate Prediction Center at National Weather Service, NOAA. The document is available at <http://www.cpc.noaa.gov/products/outreach/glossary.shtml#DD>.

²² On-peak hours are Hour Ending (HE) 8:00 a.m.–HE 10:00 p.m.

²³ Tariff Section III.H.3.1.2

cold-weather category designation a day receives (i.e., Cold Weather Watch, Warning, or Event). The ISO updates the status of Cold Weather Conditions on a daily basis according to forecasts. A Cold Weather Watch or Warning may be upgraded or downgraded in severity based on the subsequent forecasts. Cold Weather Event declarations can be made no later than two days prior to the Operating Day,²⁴ and, unlike a Cold Weather Watch or Warning, once a Cold Weather Event is declared, it cannot be cancelled.²⁵ If the ISO does not cancel a day's Cold Weather Condition status, the classification expires at the end of the day at midnight.

C. Appendix H Categories and Actions

1. Cold Weather Watch

A Cold Weather Watch may be declared for any day in the seven-day forecast period.²⁶ If the ISO declares a Cold Weather Watch for specific day(s), the ISO takes the following actions:

- A Special Notice is posted on the ISO's website:

ISO has issued a Cold Weather Watch for [dates]. Extreme Cold Weather Conditions are forecast. ISO forecasts that sufficient capacity is available to meet the forecasted demand and reserve requirements.

- The ISO notifies the local Satellite Control Centers that a Cold Weather Watch has been declared.

²⁴ As defined in Tariff Section III.H.3.1.3(c), Operating Day means the calendar day beginning at midnight, for days in which transactions in the New England electricity markets are scheduled.

²⁵ Ibid.

²⁶ See generally, Tariff Sections III.H.3.1.2 and III.h.3.1.3(a).

- During a Cold Weather Watch, the ISO grants new economic outages for the Cold Weather Watch days only if it projects that it can maintain a capacity margin of greater than 1,000 MW.

2. Cold Weather Warning

A Cold Weather Warning may be declared for any day in the seven-day forecast period.²⁷ If the ISO declares a Cold Weather Warning for specific day(s), the following actions are taken:

- A Special Notice is posted on the ISO's website:

*ISO has issued a Cold Weather Warning for [dates]. Extreme Cold Weather conditions are forecast. ISO forecasts that sufficient capacity may not be available to meet the forecasted demand and reserve requirements.*²⁸

- The ISO notifies the local Satellite Control Centers that a Cold Weather Warning has been declared.
- The ISO requests all permitted and equipped dual-fuel units that normally burn natural gas to voluntarily take all necessary steps to prepare to switch to their secondary fuel, presumably, liquid fuel oil, in anticipation of a Cold Weather Event day.
- During a Cold Weather Warning, the ISO cancels all economic outages for the period during which a Cold Weather Warning is in effect. The ISO denies any new economic outage requests for the same period. The ISO will request all generators on economic outage to return to service in accordance with OP 5.
- The ISO alerts Demand Response Market participants to be prepared to activate if and when the ISO reaches the actions of Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4), at which time they are called.

²⁷ See generally, Tariff Sections III.H.3.1.2 and III.H.3.1.3(b).

²⁸ Appendix H erroneously lists the Special Notice as alerting for an "Extreme Cold Weather Event." Appendix H will be revised to remove the word "Event."

3. Cold Weather Event

The most severe cold-weather and capacity-margin conditions may result in a Cold Weather Event.²⁹ The most significant additional action ISO must take during a Cold Weather Event is the change of the trading deadline for submitting offers and bids to the Day-Ahead Energy Market, from 12:00 noon to 9:00 a.m. of the day prior to the Operating Day. By 10:00 a.m. of the day prior to the Operating Day, gas-fired units necessary to meet forecast load and reserve requirements are advised that they will be pool-scheduled in the Day-Ahead Market. Since New England did not experience a Cold Weather Event during the winter of 2004–2005, a complete description of the respective procedures and resulting actions is not provided.³⁰

IV. Case Study: December 17–20, 2004

This section examines the outlook, weather, and capacity-margin forecasts of the cold-weather period in December 2004, considered to be December 17–20, 2004, for this case study. Applying Appendix H definitions, Cold Weather Conditions did not exist during this period. It was studied, however, because of the abrupt and unexpected change in the weather on December 20, 2004. Despite this change in the weather, the capacity margin remained positive throughout the period. This result suggests that Appendix H procedures correctly determined that it was not necessary to declare Cold Weather

²⁹ See generally, Tariff Sections 111.3.1.2 and 111.3.1.3(c).

³⁰ For details of declaration of Cold Weather Event and complete list of resulting actions see section III.H.3.1.3 (c) of Appendix H. The document is available at:

http://www.iso-ne.com/smd/market_rule_1_and_ISO_new_england_manuals/Market_Rule_1_And_Appendices/.

Conditions, but it also highlights the present vulnerability of the triggers in Appendix H to errors in the weather forecast. For example, a weather forecast that predicts higher temperatures than actually materialize may not trigger what should be a Cold Weather Condition. And, a weather forecast that predicts colder temperatures than actually occur may trigger the use of Appendix H when it is not needed.

A. Operating Conditions during the December 2004 Study Period

1. The Outlook

On Thursday, December 16, 2004, during its weekly update with the regional natural gas industry, the ISO projected daily high temperatures for the following week to be in the 35°F–40°F range, with nightly low temperatures in the 20s. The ISO also mentioned the potential that a significant winter storm might move through New England sometime on Monday morning through Tuesday afternoon. The ISO projected capacity margins of at least 8,000 MW through Friday, December 24, 2004. The regional gas pipelines did not report any operating issues for the seven days that followed.

2. Weather

Table 1 shows the forecasted and actual average on-peak effective temperature and effective HDDs for December 17–20, 2004. None of the daily weather forecasts satisfied the Cold Weather Condition requirements that the on-peak effective temperature be less than or equal to zero and the effective HDDs be 65 or more. However, the actual average on-peak effective temperature on Monday, December 20, 2004, was much lower than forecasted over the previous days, and the effective number of HDDs was higher.

While the actual weather conditions did not trigger Cold Weather Conditions, and declaring them is unlikely to be effective because the ISO has limited additional actions in real time, a more accurate forecast for December 20 possibly would have triggered Cold Weather Conditions on that day.³¹ This event highlights the vulnerability of Appendix H determinations to errors in the weather forecast. In this case, it was not problematic, but a similar error under more severe conditions could be.

Table 1 – Forecasted and Actual Average On-Peak Effective Temperature and Effective HDDs for December 17–20, 2004

Forecasted on:	Forecasted for:							
	December 17		December 18		December 19		December 20	
	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD
Dec. 17	34	36	27	43	30	40	27	42
Dec. 18			26	45	33	36	25	43
Dec. 19					35	34	12	56
Dec. 20							13	55
Actual Average	30°F	38	27°F	44	33°F	37	1°F	68

³¹ The forecast error may come from the weather services used by the ISO or from the ISO algorithms that convert the weather service forecasts into the ISO forecast. In this case, the cold-weather onset was missed by the weather services.

3. Capacity Margin

Table 2 presents the forecasted and actual capacity margins for the peak hours on December 17–20.

Table 2 – Forecasted and Actual Capacity Margin (MW) for Peak Hour of December 17–20, 2004

Dates		Forecasted for peak hour on:			
		December 17	December 18	December 19	December 20
Forecasted on:	Dec. 17	1,743	9,579	9,937	7,996
	Dec. 18		381	9,737	7,173
	Dec. 19			918	7,543
	Dec. 20				1,729
Actual	December 20	2,033	671	1,208	2,018

Note that the capacity margins that were forecasted more than a day in advance are significantly larger than those forecasts for the Operating Day. This is primarily because the start times for generating units that can be brought on-line only a day or more in advance generally prevent the units from being available in the morning for the peak hour of the same day. The ISO calculates Appendix H capacity margins used to determine cold-weather categorizations days in advance. As the time between the forecast and the Operating Day decreases, fewer generating units may be available to operate on that day because they require advance notification to operate. This is most evident for the capacity margin forecasts for the peak hour made on the same Operating Day. Many units become unavailable because adequate time is not available between the forecast and the

peak hour to start the unit and have it operating in the peak hour.³² Every day during December 17–20, the actual capacity margin remained positive. Peak load on December 20, 2004, was 22,552 MW.

B. Prices of Electricity and Fuels during the Case Study Period

Figure 1 shows the price of natural gas at selected pricing hubs during December 2004. The prices are very close across New England and do not exhibit large changes over the period. The very cold temperatures on Monday, December 20, 2004, did not trigger an increase in gas prices, since the gas trades for that day had been made on the previous Friday when the low temperatures were not forecast.

³² The capacity margin projected in the morning is always 290 MW greater than the forecast capacity margin for the same day. The 290 MW is 25% of 1,160 MW, which usually is the largest second contingency in New England and represents the Replacement Reserve Requirement. Because the ISO does not declare OP 4 when the pool is deficient in replacement reserves, the actual capacity margin is increased by the value of the replacement reserve.

Figure 1 – Price of Day-Ahead Natural Gas at Selected Pipelines during December 2004

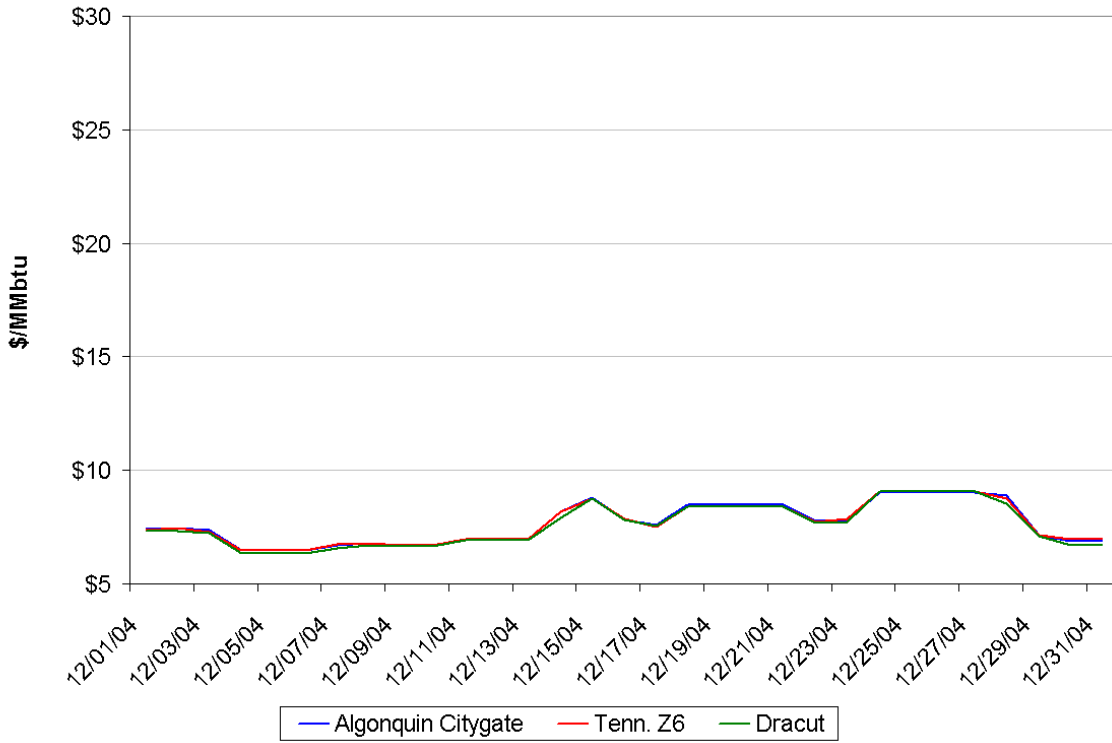
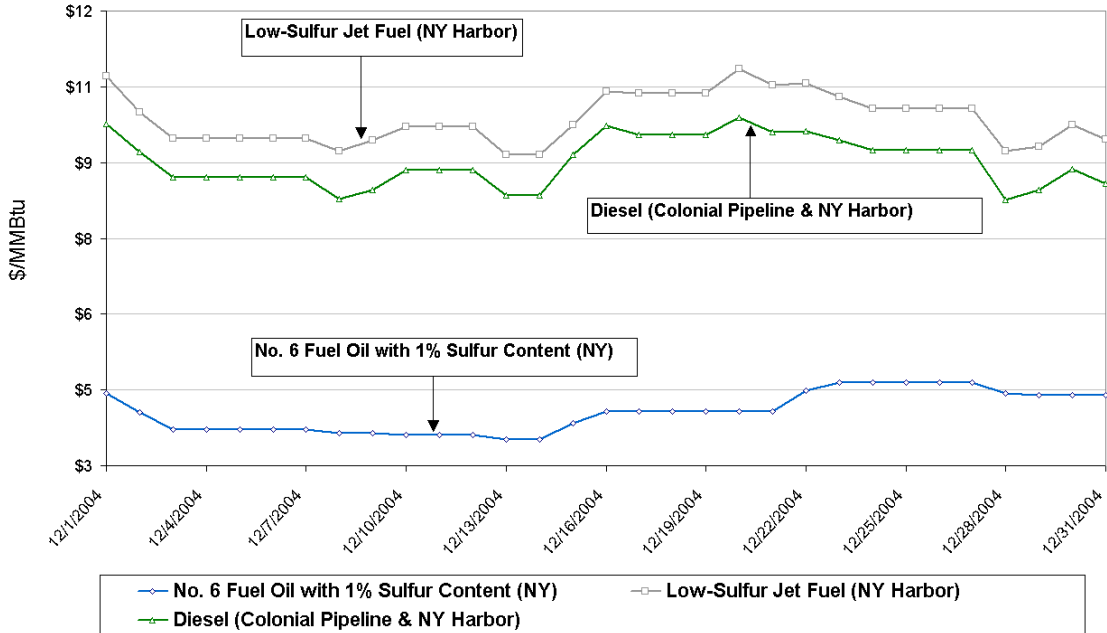


Figure 2 shows the daily price of selected fuel oils during December 2004. There was a modest increase of about 5% in the prices of diesel and low-sulfur jet fuels on December 20, but generally oil prices were stable during December 2004.

Figure 2 – Price of Selected Fuel Oils during December 2004



Given the spot price of natural gas, marginal cost can be calculated for a generator with an assumed heat rate at the applicable gas price, and the cost can be compared to actual LMPs.³³ This can aid in evaluating the incentives for gas units to procure and burn gas. Figure 3 shows an example of a power plant with the heat rate of 8 MMBtu/MWh offered with the underlying fuel price equal to the observed day-ahead average gas trade, as compared to day-ahead and real-time electricity Hub prices.³⁴ Whenever the power price is above the unit’s heat rate multiplied by the gas costs, it will be profitable for this unit to operate, assuming there are no start-up or no-load costs and there is a one-hour

³³ A generator’s heat rate is the rate at which it converts gas (MMBtu) to electricity (MWh) and measures the thermal efficiency of the conversion process.

³⁴ Day-ahead gas price is computed as the arithmetic average of day-ahead gas prices for the Algonquin Citygate, Tennessee Zone 6, and Dracut pipelines.

minimum run time.³⁵ The most efficient plants (i.e., those with heat rates below roughly 9 MMBtu/MWh) are not this flexible. There was a large increase in real-time electricity prices and a deviation of the real-time price from the day-ahead price during the evening peak on December 20, likely due to the unexpectedly cold weather. Figure 3 shows that while day-ahead electricity prices may not have caused commitment of gas units, these units had incentives to be available on the real-time market if intra-day gas prices were consistent with day-ahead gas prices. Under these conditions, intra-day gas prices might be expected to increase significantly from day-ahead gas prices, thereby reducing incentives for gas units to operate in real-time. Additional real-time offer flexibility would allow units to better reflect intra-day gas prices and better ensure proper incentives for operating under these conditions.

³⁵ Variable operations and maintenance and environmental costs are not included in this calculation. For most units, these costs are small, relative to fuel costs.

Figure 3 – Variable Production Costs of Gas Plant with a Heat Rate of 8 MMBTU/MWh, Based on Average Day-Ahead Gas Prices and Electricity Prices, for December 18–25, 2004

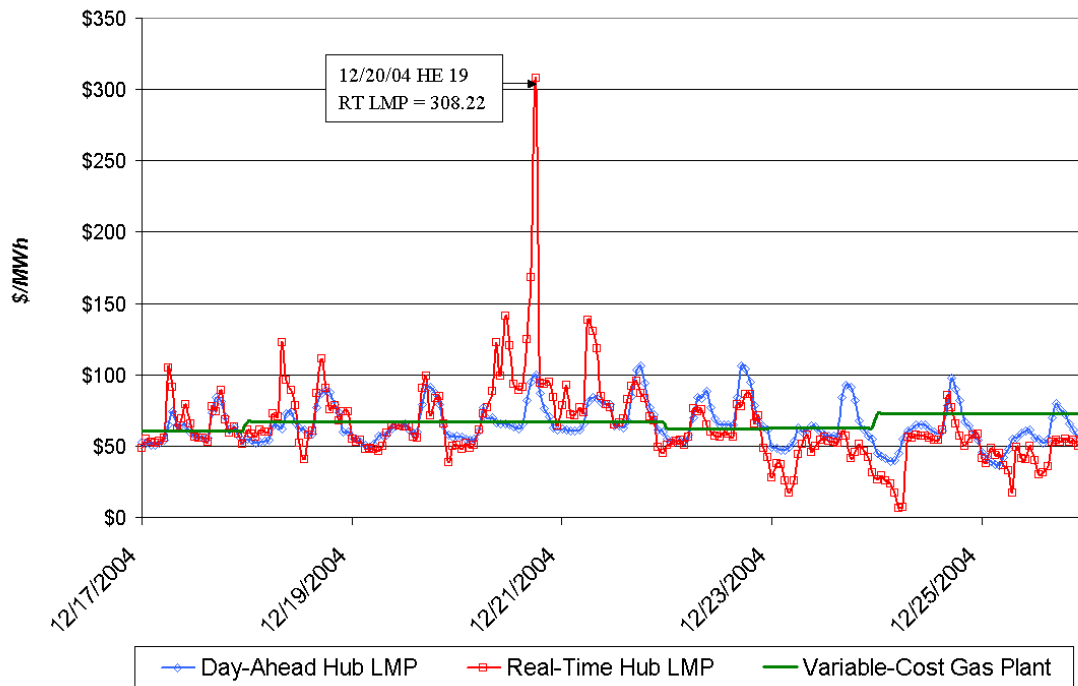


Figure 4 plots the day-ahead and real-time implied heat rates,³⁶ which are the ratios of the day-ahead and real-time prices of power shown in Figure 3 to the day-ahead price of gas in

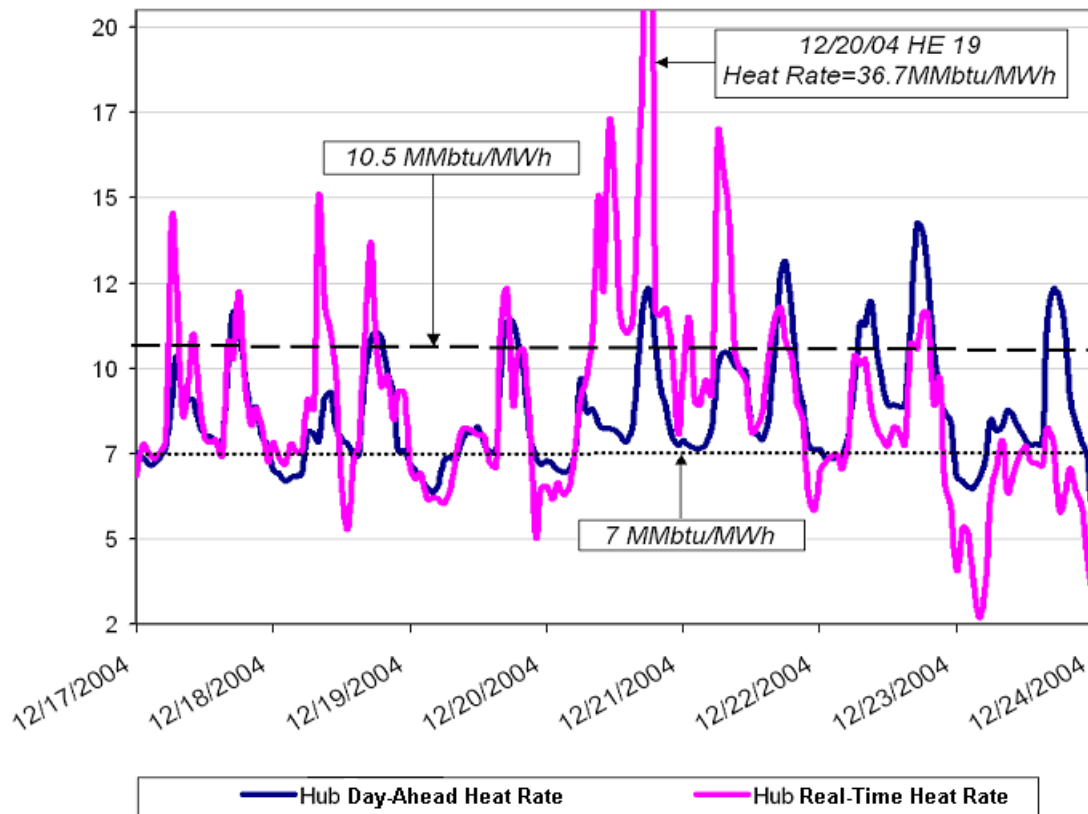
Figure 1. Also shown are the approximate efficiencies of a state-of-the-art combined-cycle plant (7 MMBtu/MWh) and a typical single-cycle combustion turbine (10.5 MMBtu/MWh) in New England.³⁷ In general, highly efficient gas-fired units were generating in-merit during the on-peak hours of December 20, 2004, in both the day-

³⁶ The implied heat rate for any day can be calculated as the ratio of forward power and forward gas prices for that day, which approximates the thermal efficiency that would be required to break even on the conversion of fuel to electricity. Variable operations and maintenance and emissions are not considered.

³⁷ One can compute the implied heat rates, using the average day-ahead and real-time price of power, at the node of each generator that runs on natural gas delivered by either the Algonquin or Tennessee gas pipelines, and their respective gas prices. During the December 2004 case-study period, the implied heat rates at all three trading locations closely track each other.

ahead and real-time markets. Again, this analysis of real-time market results assumes that day-ahead gas prices accurately reflect actual intra-day gas prices. Published indices are not available for intra-day gas prices. Higher intra-day gas prices, in this case driven by unexpectedly cold weather, would have reduced the incentives for gas units to procure fuel and operate. Additional real-time offer flexibility would help to address this issue.

Figure 4 – Implied Day-Ahead Forward Heat Rate for Gas Units for December 17–25, 2004



C. Unit Availability

Table 3 shows generator outages and reductions for the peak hour of December 20, 2004.^{38, 39} That day, outages and reductions were typical for a winter day. The daily average for December 2004 was 3,695 MW of outages and reductions; on December 20, the total was 3,683 MW. The amount of economic outage on December 20 was low (approximately 58 MW). The weather-related outages that day totaled 207 MW, and reductions totaled 180 MW.⁴⁰ The number of fuel- and weather-related outages on December 20 suggests that the risk of outage for a unit increases when Cold Weather Conditions occur. Thus, it is appropriate that the ISO continues to forecast an increased number of unit outages during Cold Weather Conditions.

³⁸ Economic outages, as defined in OP 5, are those approved by the ISO and requested for non-physical reasons. Non-economic outages include non-weather equipment outages, such as “typical” forced outages or tube leaks. Fuel- or weather-related outages are, respectively, outages due to a lack of fuel availability (e.g., natural gas pipeline restraints) or forced outages due to weather-related problems (e.g., frozen fuel lines). Other outages are those that cannot be accurately categorized with data that are readily available to the ISO.

³⁹ The hourly average MW of “other” outages and reductions are close to the peak hour numbers. The hourly average economic reductions were 615 MW; however, there were no economic reductions during the peak hour.

⁴⁰ With one exception, these units were different from those that experienced fuel- or weather-related outages during the January 2004 Cold Snap. This one unit was not able to procure gas in each instance. This dual-fuel unit would likely be able to burn oil if a Cold Weather Event were declared.

Table 3 – Generator Outage and Reductions (MW) for December 20, 2004, HE19

Generator Outages (MW) for December 20, 2004, HE19

Unit Fuel Type	Outage					Subtotal Outages
	Economic	Fuel/ Weather	Annual Inspection	Forced/ Other Explained Outages	Other	
Gas Capable - Primary	57.77	207.09	941.66	387.93	-	1,594.45
Coal	-	-	-	-	-	-
Oil Only	-	-	35.88	-	-	35.88
Hydro	-	-	69.75	292.28	-	362.03
Other	-	-	-	-	-	-
Subtotal	57.77	207.09	1,047.29	680.21	-	1,992.36

Generator Reductions (MW) for December 20, 2004, HE19

Unit Fuel Type	Reductions					Total Outages/Reductions		
	Economic	Fuel/ Weather	Annual Inspection	Forced/ Other Explained Outages	Other	Subtotal Reductions	Total	Percent
Gas Capable - Primary	-	180.38	-	955.90	277.58	1,413.86	3,008.31	82%
Coal	-	-	-	28.00	-	28.00	28.00	1%
Oil Only	-	-	-	-	42.45	42.45	78.32	2%
Hydro	-	-	-	-	144.58	144.58	506.61	14%
Other	-	-	-	31.89	29.55	61.44	61.44	2%
Subtotal	-	180.38	-	1,015.79	494.16	1,690.33	3,682.69	100%

"Other Explained Outages" includes:

- Ambient air
- Administrative
- System contingency
- Postured
- Transmission limitations

D. Conclusions for the December 2004 Case Study

Total outages were normal during the December study period, despite those that appeared to be due to cold weather. The cold weather-related outages suggest that the ISO should continue to reflect an increased number of outages in its capacity-margin forecasts during periods of cold weather. There were no Cold Weather Conditions, as defined by Appendix H, during this period. This determination is consistent with observed fuel prices and reliable system operations. High real-time electricity prices reflect that weather conditions were colder than expected given the weather forecast. Although the weather on December 20, 2004, turned out to be much colder than forecasted, the capacity margin remained positive—2,018 MW for the peak hour—without the need to implement Appendix H actions. This event highlights the vulnerability of the present Appendix H procedures to errors in the weather forecast.⁴¹ The ISO may want to consider improving its understanding of the uncertainty of weather forecasts,⁴² and incorporate forecast uncertainty into some of the Appendix H triggering events.

Analysis of day-ahead gas prices shows that gas units were inframarginal during real-time.⁴³ However, because of the error in the weather forecast, intra-day gas prices may have been significantly higher.

⁴¹ The ISO purchases three different commercial weather forecasts and uses each to produce a composite forecast as an input to the load-forecasting process.

⁴² For example, the ISO may want to better understand forecast uncertainties related to the season, hour of the day, and prior weather conditions.

⁴³ Inframarginal units that submit lower offers than the marginal units(s) setting the LMP(s) are higher in the merit-commitment order.

V. Case Study: January 18–22, 2005

This section reviews the Cold Weather Watch and Warning conditions that were triggered during the week of January 16–22, 2005 (January 2005 study period). A Cold Weather Watch was declared on January 19 for Operating Day January 21. On January 20, this condition was upgraded to a Cold Weather Warning for January 21. No other days during the January 2005 study period were categorized as having Cold Weather Conditions. The section reviews the actual weather and operating conditions in the natural gas and electricity markets in New England during that week, including gas-fired units that were operating out-of-merit. The section concludes with an assessment of Appendix H's performance during this period.

A. Operating Conditions and Actions during the January 2005 Study Period

1. The Outlook

During its weekly update with the regional natural gas industry on Thursday, January 13, 2005, the ISO projected daily high temperatures of 30°F and low temperatures of 15°F for the following week starting Sunday, January 16. The ISO also forecasted adequate capacity margins, expected to be above 8,000 MW. No gas pipeline reported any anticipated problems for the upcoming week.

2. Weather

Prior to January 19, 2005, the weather forecast did not predict or trigger any Cold Weather Conditions, although the forecast for January 18 was very close to triggering Cold Weather Conditions.⁴⁴ Unlike the December study period, the weather forecasts for this period were only slightly off. By January 19, the weather forecast was revised and predicted much colder conditions. Beginning January 19, the forecast predicted and triggered Cold Weather Conditions for January 21, in accordance with Appendix H.

Table 4 shows the New England forecasts and actual average on-peak effective temperatures and effective HDDs for January 18–21, 2005.

Table 4 – Forecasted and Actual Average On-Peak Effective Temperature (°F) and Effective HDDs for January 18–21, 2005

Forecasted on:	Forecasted for Peak Hours on:							
	January 18		January 19		January 20		January 21	
	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD
Jan. 18	1	67	13	58	21	48	8	61
Jan. 19			14	57	20	48	0	68
Jan. 20					18	51	0	68
Jan. 21							-1	69
Actual Average	-3°F	71	11°F	58	14°F	55	-4°F	72

⁴⁴ Note that actual weather conditions are irrelevant for triggering Appendix H Cold Weather Conditions. If actual weather conditions could trigger them, those on January 18 would have done so.

3. Capacity Margin

Table 5 shows forecasted and actual capacity margins for the peak hours of January 18–21, 2005. On January 19, the expected capacity margin for January 21 was above 1,000 MW, which, when combined with the Cold Weather Conditions forecast for that day, triggered a Cold Weather Watch. By January 20, the capacity-margin forecast for January 21 was below 1,000 MW, triggering an upgrade in severity to a Cold Weather Warning. Because the capacity margin was forecast to be positive, no Cold Weather Event was forecasted.⁴⁵ Peak electricity load on January 21 was 21,136 MW.

Table 5 – Forecasted and Actual New England Capacity Margin (MW) for Peak Hour on January 18–21, 2005

Dates		Forecasted for peak hour on:			
		January 18	January 19	January 20	January 21
Forecasted on:	Jan. 18	1,151	4,464	7,178	4,836
	Jan. 19		3,078	4,134	1,582
	Jan. 20			1,319	702
	Jan. 21				695
Actual	Jan. 21	1,441	3,368	1,609	984

4. Appendix H Implementation

At 11:25 a.m. on January 19, in accordance with Appendix H, the ISO issued a Cold Weather Watch for January 21. This was based on a forecast of Cold Weather

⁴⁵ Capacity margins that were forecasted more than a day in advance were significantly larger than the forecasts made during the Operating Day. This is primarily because units with long start times cannot be brought on-line in the morning and be available for the peak hour of the same day.

Conditions and an expected capacity margin greater than 1,000 MW. Following the Cold Weather Watch declaration, the ISO undertook the following actions in accordance with Appendix H:

- At 11:30 a.m., the ISO posted a Special Notice on its website:
ISO has issued a Cold Weather Watch for January 21, 2005. Extreme Cold Weather Conditions are forecast. ISO forecasts that sufficient capacity is available to meet the forecasted demand and reserve requirements.
- By 1:35 p.m., the ISO notified the local Satellite Control Centers that a Cold Weather Watch had been declared.
- Throughout the day, the ISO continued to monitor regional gas pipeline EBBs and review Informational Postings by the individual pipeline operators.

Additionally, the ISO notified state regulators that a Cold Weather Watch had been declared.

At 12:06 p.m., on January 20, 2005, the ISO issued a Cold Weather Warning for January 21, 2005, in accordance with Appendix H. This upgrade from the previously issued Cold Weather Watch was triggered by a decrease in the forecast capacity margin to below 1,000 MW. Following the Cold Weather Warning, the ISO undertook the following actions in accordance with Appendix H and its general authority to cancel economic outages:

- At 12:10 p.m., the ISO posted a Special Notice on its website:
ISO has issued a Cold Weather Warning for January 21, 2005. Extreme Cold Weather Event conditions are forecast. ISO forecasts that sufficient

*capacity may not be available to meet the forecasted demand and reserve requirements.*⁴⁶

- By 1:35 p.m., the ISO notified the local Satellite Control Centers that a Cold Weather Warning has been declared.⁴⁷
- Immediately after notifying the local Satellite Control Centers, the ISO requested that all permitted and equipped dual-fuel units that normally burn natural gas voluntarily take all necessary steps to prepare to switch to a secondary fuel, presumably liquid fuel oil. Each dual-fuel power station was contacted and asked about its plans to switch to a secondary fuel and how long that process would take.
- At 12:59 p.m., the ISO canceled all economic outages for the Cold Weather Warning day and requested all generators on economic outages to return to service in accordance with OP 5.⁴⁸
- By 1:35 p.m., the ISO alerted all Demand Response Participants that they should prepare to be activated if and when the ISO reaches the actions of OP 4, at which point they would be called.⁴⁹
- The ISO continued to monitor regional natural gas pipeline EBBs and review informational postings by the individual pipeline operators throughout the day.

Additionally, the ISO notified state regulators that a Cold Weather Warning had been declared.⁵⁰ At 4 p.m., the ISO conducted a teleconference to brief state regulators on the Cold Weather Warning.

⁴⁶ The second sentence of the Special Notice should have said: “Extreme Cold Weather Conditions are forecast.”

⁴⁷ The problems with the mail server caused delay, and fewer participants than intended received the notice.

⁴⁸ There were no requests for new economic outages on January 21, 2005, after this action. Any such requests would have been denied in accordance with Appendix H.

⁴⁹ The problems with the mail server caused delay, and fewer participants than intended received the notice.

⁵⁰ “State regulators” include New England’s state public utility commissions and certain state, regional, and federal energy offices and New England’s state air regulators. The ISO’s External Affairs Department follows a communications protocol to ensure that state regulators are notified if the ISO declares a Cold Weather Watch, Warning, or Event. These communications emphasize to state air regulators the request for

On January 21, 2005, the ISO did not change the status or cancel the previously issued Cold Weather Warning, and it expired at midnight on January 21. The ISO notified state regulators of the anticipated expiration of the Cold Weather Warning.

B. Prices of Electricity and Fuels during the January 2005 Study Period

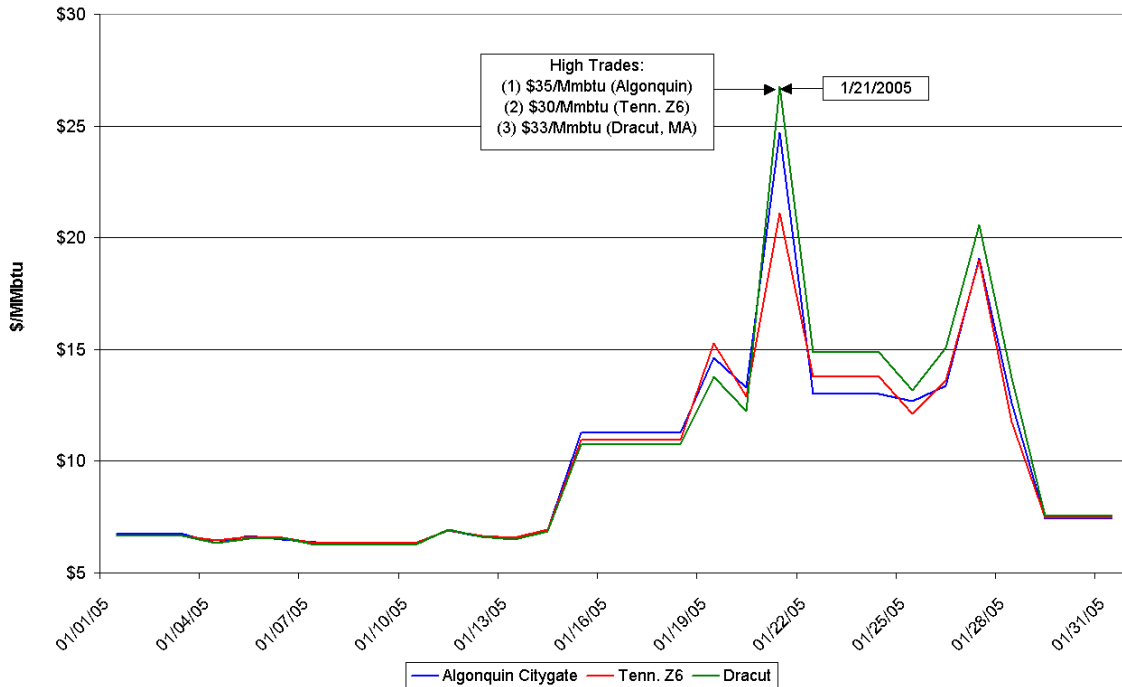
Figure 5 shows the price of natural gas at selected New England trading locations during the month of January 2005. Over the first half of the month, natural gas prices were very similar throughout New England and showed little volatility. However, coincident with the beginning of the January 2005 study period, there was a significant increase in natural gas prices, as well as price separation between different pricing points.

Natural gas prices hit a seasonal high in the day-ahead gas market for Northeast price points on January 21, 2005, with a high-trade price of \$35.00/MMBtu reported at Algonquin Citygate. The average trade price for Algonquin Citygate on January 21 was \$24.71/MMBtu.⁵¹ Over the January 2005 study period, gas pipelines experienced numerous capacity constraints and operating restrictions. Appendix B provides the timeline of events on the regional natural gas pipelines for this period.

generators to switch to secondary fuels. To the extent that system conditions lead to the implementation of OP 4, the ISO follows established protocols for notification of such actions.

⁵¹ On January 21, 2005, the high trade for Tennessee Zone 6 was \$30.00/MMBtu, and the average trade was \$21.12/MMBtu; on Dracut, the high trade was \$33.00/MMBtu, and the average trade was \$26.76/MMBtu. The high trade on Iroquois was \$30.00/MMBtu, and the average was \$24.52/MMBtu.

Figure 5 – Price of Day-Ahead Natural Gas at Selected Pipelines during January 2005



The price dynamics of natural gas during January 2005 contrast sharply with the price behavior of fuel oils that month; the latter is shown in

Figure 6. There was only a modest, gradual price increase in the fuel oil markets in the second half of January, with no clear increase in price volatility, unlike the behavior of regional natural gas prices. Given relative natural gas and fuel oil prices during the January 2005 study period, the use of oil should have been an attractive economic option for plants with this capability.

Figure 6 – Price of Selected Fuel Oils during January 2005

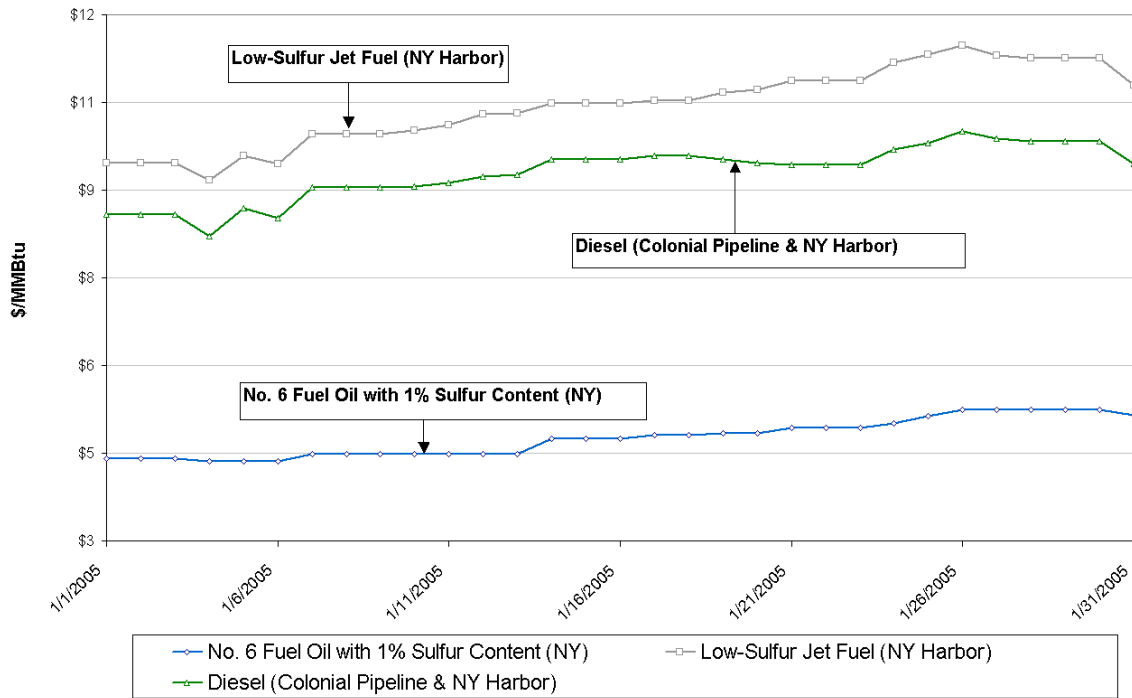


Figure 7 shows production costs of a power plant with a heat rate of 8 MMBtu/MWh during January 15–22, 2005, using day-ahead gas prices. These costs are contrasted with day-ahead and real-time electricity prices. There was an increase in day-ahead and real-time electricity prices during Friday, January 21, 2005, with day-ahead prices higher. This is the opposite of the relationship seen on December 20, 2004, when real-time prices exceeded \$308/MWh (cf. Figure 3). However, this increase did not enable even the most efficient generators to operate in-merit at spot-gas prices, as production costs for gas units were higher than electricity prices during most of the hours, as shown in Figure 7.

Figure 7 – Variable Production Costs of Gas Plant with a Heat Rate of 8 MMBTU/MWh, Based on Average Day-Ahead Gas Prices and Day-Ahead and Real-Time Electricity Prices, for January 15–22, 2005

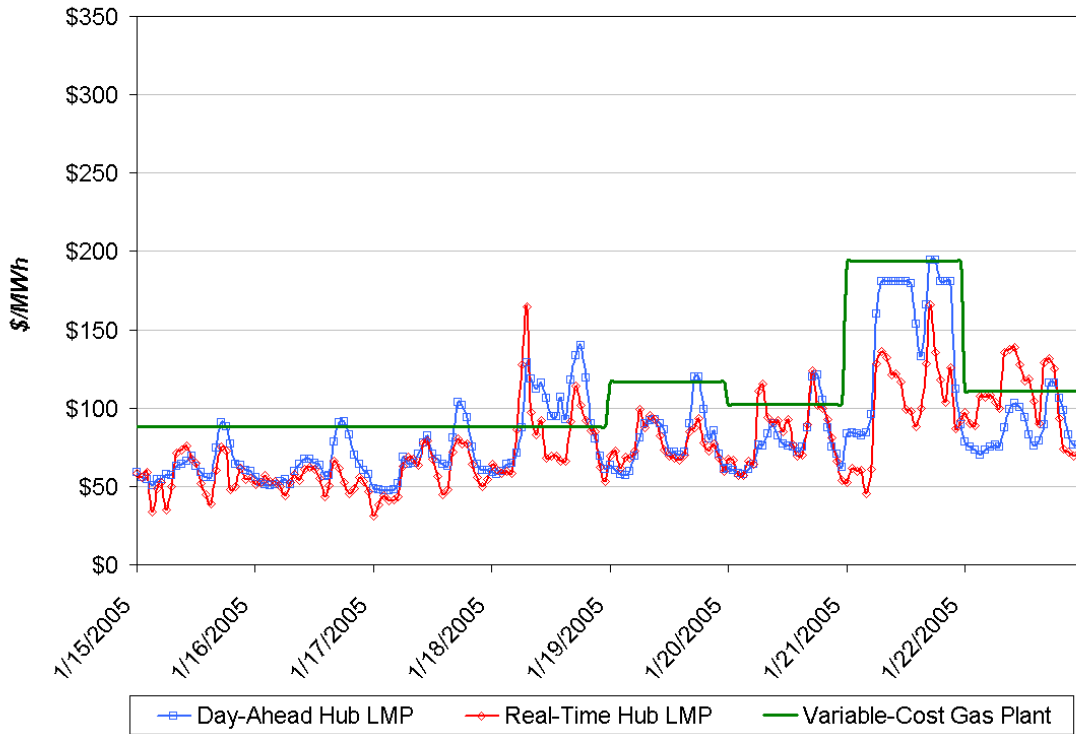
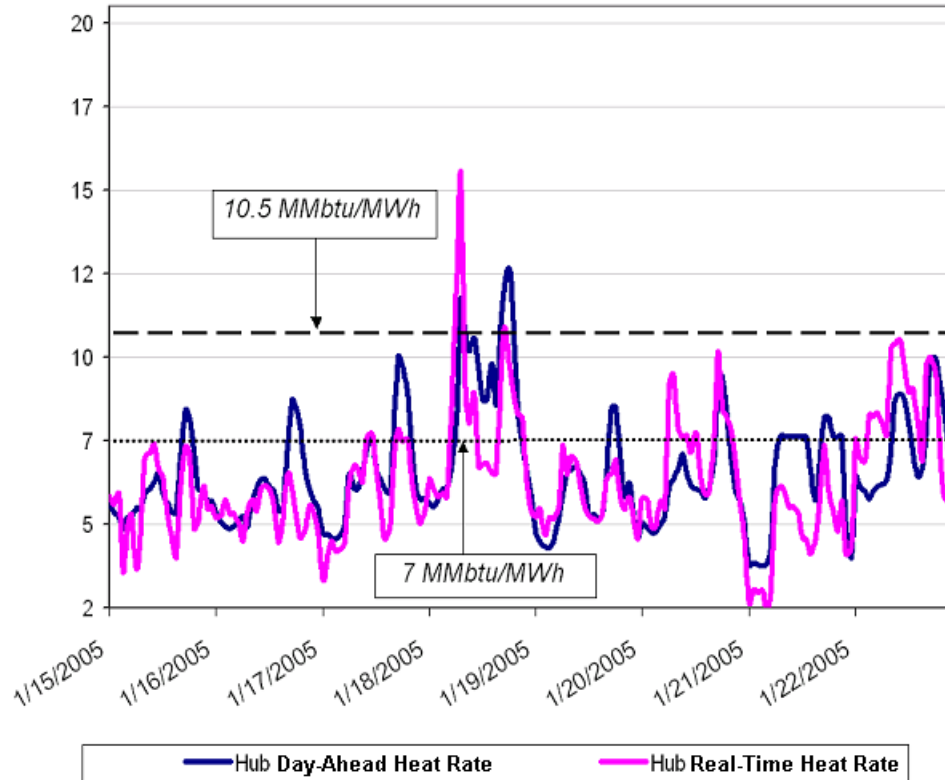


Figure 8 plots the day-ahead and real-time implied heat rates at the New England Hub, which are the ratios of the day-ahead and real-time prices of power shown in Figure 7 to the day-ahead price of natural gas shown in

Figure 5. Except for January 18, many gas-fired units were not inframarginal in the Day-Ahead Energy Market during the week of the January 2005 study period, unlike the December 2004 study period (cf. Figure 4). On January 21, 2005, the most efficient gas-fired units would have been inframarginal for only a few hours in the Day-Ahead and Real-Time Energy Markets.

Figure 8 – Implied Day-Ahead Forward Heat Rate for Gas Units for January 15–22, 2005

C. Out-Of-Merit Commitments

Table 6 shows the daily dollar amount of Operating Reserve Credits (ORCs) charged in Day-Ahead and Real-Time Energy Markets, according to fuel type of the recipients, during the week of January 16–22, 2005. During that week, there were ORCs for Economic (EOR), Reliability Must Run (RMR), and Voltage Amperes Reactive (VAR) Operating Reserve, but none for Special Constraint Resources (SCRs). Gas units operating in real-time accounted for the large majority of ORC, which were split nearly evenly between Economic and RMR Operating Reserve Credits. The largest amount of ORC during the week was attributable to the real-time EOR and Reliability Must Run reserves of the gas-only generation on January 21, 2005. These Operating Reserve

Credits accounted for over 44% of all ORC for the week.⁵² These charges were well below those incurred during the January 2004 Cold Snap.

⁵² Additional data on ORC and out-of-merit generation is contained in the presentation by the ISO to the NEPOOL Markets Committee of March 29, 2005, *Review of Winter Season LMP Setting*. The document is available at http://www.iso-ne.com/committees/markets/2005_03_29/.

Table 6 – Operating Reserve Payments (\$) during the Week of January 16–22, 2005

Fuel Type	Service Type	Jan-16			Jan-17			Jan-18			Jan-19			Jan-20		
		EOR	RMR	VAR	EOR	RMR	VAR	EOR	RMR	VAR	EOR	RMR	VAR	EOR	RMR	VAR
Gas	Day-Ahead			220,674.15	11,100.74		176,996.55				182,538.25			48,083.60		
	Real-Time	176,136.14	300,356.34		77,136.57	309,460.44		128,156.83	609,769.91		1,765.13	137,626.46			264,751.68	
Hydro	Day-Ahead	104.95														
	Real-Time									1,756.17						
Jet Fuel	Day-Ahead															
	Real-Time							7,370.34								
Oil	Day-Ahead				352.10			117.99								
	Real-Time							44.88		57,562.02			27,347.84			
Oil/Gas	Day-Ahead				840.80			340.20								
	Real-Time	19,767.24						6,797.27								
Total	Day-Ahead	104.95	0.00	220,674.15	12,293.64	0.00	176,996.55	458.19	0.00	0.00	182,538.25	0.00	0.00	48,083.60	0.00	0.00
	Real-Time	195,903.38	300,356.34	0.00	77,136.57	309,460.44	0.00	142,369.32	609,769.91	0.00	61,083.32	137,626.46	0.00	27,347.84	264,751.68	0.00
Grand Total		196,008.33	300,356.34	220,674.15	89,430.21	309,460.44	176,996.55	142,827.51	609,769.91	0.00	243,621.57	137,626.46	0.00	75,431.44	264,751.68	0.00

Fuel Type	Service Type	Jan-21			Jan-22			Total			Grand Total
		EOR	RMR	VAR	EOR	RMR	VAR	EOR	RMR	VAR	
Gas	Day-Ahead	57,182.41						298,905.00	0.00	397,670.70	696,575.70
	Real-Time	1,729,021.24	853,999.25		148,502.84	203,380.05		2,260,718.75	2,679,344.13	0.00	4,940,062.88
Hydro	Day-Ahead							104.95	0.00	0.00	104.95
	Real-Time				5,706.36			7,462.53	0.00	0.00	7,462.53
Jet Fuel	Day-Ahead	321.64						321.64	0.00	0.00	321.64
	Real-Time							7,370.34	0.00	0.00	7,370.34
Oil	Day-Ahead							470.09	0.00	0.00	470.09
	Real-Time				23,713.18			108,667.92	0.00	0.00	108,667.92
Oil/Gas	Day-Ahead	11,564.80						12,745.80	0.00	0.00	12,745.80
	Real-Time				2,891.69			29,456.20	0.00	0.00	29,456.20
Total	Day-Ahead	69,068.85	0.00	0.00	0.00	0.00	0.00	312,547.48	0.00	397,670.70	710,218.18
	Real-Time	1,729,021.24	853,999.25	0.00	180,814.07	203,380.05	0.00	2,413,675.74	2,679,344.13	0.00	5,093,019.87
Grand Total		1,798,090.09	853,999.25	0.00	180,814.07	203,380.05	0.00	2,726,223.22	2,679,344.13	397,670.70	5,803,238.05

To show the effect that Out-Of-Merit (OOM) commitment has on LMPs, Table 7 presents data on price-setting and inframarginal units for two Scheduling, Pricing, and Dispatch (SPD) software runs on January 21, 2005. These price effects are important, because LMPs that do not accurately reflect the marginal costs of needed resources do not provide the appropriate incentives for units to operate. Resources dispatched at economic minimum reduce LMPs because they affect prices in the same way as a zero offer, even though the offer submitted for the unit might be priced much higher. The problem of low LMPs was especially acute during the January 2004 Cold Snap, when the marginal cost of gas units was well above LMPs, yet thousands of MW of gas-fired generation were dispatched. These data focus on two hours, HE 3:00 p.m. and HE 6:00 p.m. The former hour (low \$ SPD) was selected because it was an especially low-priced on-peak interval. HE 6:00 p.m. (high \$ SPD) was chosen because it had the highest Hub LMP for the day.⁵³

⁵³ The peak load hour of the day was HE 7:00 pm.

Table 7 – Data on Price-Setting and Inframarginal Units

	1/21 - Low \$ SPD	1/21 - High \$ SPD
Load	18,946	21,046
Marginal Unit Setting Price (Type)	Oil/Gas	Hydro
Marginal Unit Setting Price (\$/MWh)	\$82.00	\$150.00
Out-of-Merit MWh (All Fuel Types)	1,423	387
Price Without OOM MW	\$120.00	\$166.94
Price Effect (\$)	\$38.00	\$16.94
Price Effect (% Decrease)	32%	11%
Integrated Hourly \$/MWh (Real-Time Hub)	\$88.08	\$165.81
Hourly Capacity Margin	2,967	1,257
OOM MW Flagged VAR⁵⁴	-	-
OOM MW Flagged Daily RMR	90	90
OOM MW Economic	1,333	297

In HE 3:00 p.m., a dual-fuel (oil/gas) unit was setting the dispatch rate at \$82/MWh. Generation of 1,423 MW, most of it gas-fired, was running at its economic minimum, which made it ineligible to set the LMP. This effect decreased LMPs by approximately \$38/MWh or 32%. In HE 6:00 p.m., the price was \$150/MWh, and OOM generation was only 387 MW, with approximately 50 MW gas-fired. In that hour, the price would have been \$17/MWh higher without the units that were running at economic minimum. The integrated hourly numbers show that the SPD runs were reasonably representative of the hour as a whole. The estimated marginal cost of an efficient gas unit on this day was \$198/MWh.

The number of OOM megawatts was lower than during similar periods of the January 2004 Cold Snap, especially over the peak hour.⁵⁵ The price effects were also smaller. The large

⁵⁴ Flagging is an ISO procedure that designates certain generators for RMR, VAR, and SCR Operating Reserves in day-ahead and real-time markets.

number of OOM megawatts during the low-priced period was due to a combination of unit inflexibility and capacity requirements during the peak hour. These OOM megawatts could not have been decommitted and still have been available during the peak hour, and it was expected that they would be needed for reliability during the peak hour.⁵⁶ The LMP effects of unit inflexibility are significant, but there do not appear to have been economic alternatives to the commitment and dispatch of these inflexible units.

Out-of-merit operation over the peak hour was relatively low, with less than 300 MW (approximately 1.4% of hourly load) of unflagged resources, plus 90 MW flagged as daily RMR. The price effect was also more modest. Of these unflagged MW, 220 MW (one unit) were not committed in the Day-Ahead Energy Market. These MW were priced at \$151/MW, one dollar over the marginal unit, and likely would have become inframarginal if decommitted. All of the remaining 77 MW were committed in the Day-Ahead Energy Market, with some given lower dispatch points in real-time.⁵⁷ These results suggest remarkably little excess real-time commitment, given the uncertainties inherent in real-time dispatch (e.g., load forecasts, unit outages, self-schedules and net imports). It is not clear that further reductions in OOM operation over the peak hour were practical with current resources while maintaining system reliability.

The in-merit operation of significant quantities of gas-fired generation in each hour, either at submitted offer prices or due to self-scheduling, also contributed to relatively low LMPs

⁵⁵ On January 15, almost 2,100 MW of gas units were at economic minimum during HE 2:00 p.m., and almost 1,200 MW were at economic minimum during the peak-load hour of HE 7:00 p.m.

⁵⁶ Additional details on OOM generation and unit inflexibility during this and other periods are provided in the ISO's presentation to the NEPOOL Markets Committee on March 29, 2005, Review of Winter Season LMP Setting. The document is available at http://www.iso-ne.com/committees/markets/2005_03_29/.

⁵⁷ By its rules and procedures, the ISO does not decommit units with a Day-Ahead Energy Market schedule unless the lead participant requests decommitment.

during January 21. These units were operating at LMPs below their estimated marginal costs. During HE 3:00 p.m., about 1,200 MW of gas units, and 4,000 MW of gas/oil units were either self-scheduled or inframarginal. During HE 6:00 p.m., about 1,350 MW of gas units were self-scheduled or inframarginal, with about 5,000 MW of gas/oil units self-scheduled or inframarginal.

D. Unit Availability

Table 8 provides information on unit outages and reductions for the peak hours of January 20–21, 2005. The table shows that 569 MW of gas-fired generation was on economic outage during the peak hour on January 20, 2005. By the peak hour on January 21, all units had returned from economic outage and declared themselves available for dispatch. There were no units on economic outage during the peak hour on January 21, 2005.⁵⁸ Overall, there were about 2,741 MW of outages and reductions over the peak hour on January 21, which is less than the outages typically experienced on a winter day. In particular, the average amount of outages and reductions in January 2005, excluding the week of January 17–22, 2005, was 3,717 MW. One gas-fired unit caused the 273 MW of fuel/weather-related outages during the peak hour on January 21; no such outages were reported on January 20. The 273 MW figure is small relative to the daily total, based on the ISO’s experience during the January 2004 Cold Snap.⁵⁹ The “other” outage category includes those for which the ISO could not establish or classify the

⁵⁸ The hourly average MW of outages and reductions are close to the peak hour numbers. For example, the hourly average of total outages and reductions was approximately 3,135 MW on January 20, and 2,758 MW on January 21. Economic outage totals are almost identical.

⁵⁹ This unit did experience an outage during the January 2004 Cold Snap because the lead participant was unable to procure natural gas. This outage was not related to fuel procurement, but was caused by a frozen line.

cause. Further discussion with participants might have aided in identifying the outages categorized as “other,” although the small number of MW involved made this seem unnecessary. Total outages and reductions fell by 285 MW from January 20 to January 21, largely because of the cancellation of economic outages. Without the cancellation of economic outages and the return to service of these units, the actual capacity margin over the peak hour would have been slightly over 400 MW.

Table 8 – New England’s Generator Outages and Reductions (MW) for the Peak Hour on January 20, 2005, and January 21, 2005

Generator Outages (MW) for January 20, 2005, HE19

Unit Fuel Type	Outage					Subtotal Outages
	Economic	Fuel/ Weather	Annual Inspections	Forced/ Other Explained Outages	Other	
Gas Capable - Primary	569.37	-	164.91	267.24	-	1,001.52
Coal	-	-	-	-	-	-
Oil Only	-	-	21.72	23.34	-	45.06
Hydro	-	-	83.74	293.05	-	376.80
Other	-	-	44.30	-	-	44.30
Subtotal	569.37	-	314.68	583.63	-	1,467.68

Generator Reductions (MW) for January 20, 2005, HE19

Unit Fuel Type	Reductions						Total Outages/Reductions	
	Economic	Fuel/ Weather	Annual Inspections	Forced/ Other Explained Outages	Other	Subtotal Reductions	Total	Percent
Gas Capable - Primary	-	-	-	1,245.13	73.44	1,318.57	2,320.08	78%
Coal	-	-	-	28.00	-	28.00	28.00	1%
Oil Only	-	-	-	-	15.52	15.52	60.58	2%
Hydro	-	-	-	58.91	70.38	129.29	506.09	17%
Other	-	-	-	-	12.10	12.10	56.41	2%
Subtotal	-	-	-	1,332.04	171.44	1,503.48	2,971.16	100%

"Other Explained Outages" includes:

- Ambient air
- Emissions
- Administrative
- Transmission constraint

Table 8 – New England’s Generator Outages and Reductions (MW) for the Peak Hour on January 20, 2005, and January 21, 2005 (Continued)

Generator Outages (MW) for January 21, 2005, HE19

Unit Fuel Type	Outage					Subtotal Outages
	Economic	Fuel/ Weather	Annual Inspection	Forced/ Other Explained Outages	Other	
Gas Capable - Primary	-	273.27	-	553.19	38.45	864.91
Coal	-	-	-	-	-	-
Oil Only	-	-	21.72	147.51	17.13	186.35
Hydro	-	-	83.74	293.05	-	376.80
Other	-	-	44.83	24.32	25.66	94.81
Subtotal	-	273.27	150.29	1,018.07	81.24	1,522.86

Generator Reductions (MW) for January 21, 2005, HE19

Unit Fuel Type	Reductions						Total Outages/Reductions	
	Economic	Fuel/ Weather	Annual Inspection	Forced/ Other Explained Outages	Other	Subtotal Reductions	Total	Percent
Gas Capable - Primary	-	-	-	981.97	68.87	1,050.84	1,915.74	70%
Coal	-	-	-	28.00	-	28.00	28.00	1%
Oil Only	-	-	-	-	15.52	15.52	201.87	7%
Hydro	-	-	-	-	111.72	111.72	488.52	18%
Other	-	-	-	-	12.10	12.10	106.91	4%
Subtotal	-	-	-	1,009.97	208.21	1,218.18	2,741.04	100%

"Other Explained Outages" includes:

- Ambient air
- Administrative
- System contingency

E. Impact of Appendix H Implementation

Appendix H seeks to ensure a positive capacity margin and prevent Cold Weather Events by triggering actions that provide more accurate information to the marketplace. The procedures' effectiveness in providing this information is difficult to determine. This section reviews two quantifiable areas of focus in the *January 2004 Cold Snap Report*, dual-fuel switching and economic outage recall, during the January 2005 study period.

During the period of this case study, twenty-one permitted and equipped dual-fuel units that normally burn natural gas were contacted about their fuel-switching operations. Seven of them provided electricity for the peak hour, all using liquid fuel oil, totaling 1,050 MW of capacity during the peak hour on January 21, 2005. This generation cannot be exclusively attributed to the Appendix H actions that took place during this period, since the decisions to convert to a secondary fuel could have been made independently of and prior to the Cold Weather Warning declaration.

One of the Appendix H actions the ISO undertook after declaring the Cold Weather Warning was to cancel all economic outages. The total impact of canceled and denied economic outages, along with conversions to a secondary fuel, resulted in the availability of 1,619 MW during the peak hour on January 21, 2005. The capacity margin on January 21 was 984 MW. Thus, these actions by the ISO and participants may have helped to prevent the triggering of a Cold Day Event.

F. Conclusions for the January 2005 Case Study

An Appendix H Cold Weather Watch and Warning were triggered during the January 2005 study period. Market and system operations were normal during the period. While actual conditions on January 18 would have triggered Cold Weather Conditions, forecast conditions were less severe and did not trigger action under Appendix H. Given the observed low-market prices and reliable system operations, not triggering Appendix H was appropriate. January 21 was appropriately forecast as a Cold Weather Warning day, with forecast and actual capacity margins less than 1,000 MW and volatile gas prices. Unit outages on January 21 were below those experienced during typical winter days, as the cancellation of economic outages increased the available resources. Many dual-fuel resources switched to secondary fuels, a response consistent with the observed levels of fuel prices.

Prices during the study period often were below the supply-offer price calculated for an efficient gas unit, based on day-ahead gas prices, though some gas units were inframarginal or marginal at their offer prices. While ORC increased, out-of-merit operation during the peak hour was not high, and the units operating out-of-merit were either flagged for local-transmission support, had day-ahead commitments, or were within one dollar of the marginal unit. Peak-hour prices were consistent with the offers of the more expensive gas-fired units that were dispatched. There does not appear to be much scope for improved commitment over the peak hour studied. Much of the ORC appears to reflect inflexible units run during the mid-day period to span the morning and evening peaks. Operation of these units contributed to lower LMPs during the mid-day hours.

VI. Other Periods of Cold Weather

Except for January 21, 2005, Cold Weather Conditions were not forecast during winter 2004–2005. However, other days experienced low temperatures coupled with tight gas supply, high ORC, and higher-than-normal LMPs. One such day was January 27, 2005. Table 9 shows the New England forecast and actual average on-peak effective temperatures and effective HDDs for January 24–27, 2005. Lower temperatures were accurately predicted.⁶⁰ No Cold Weather Conditions were triggered by this forecast.

Table 9 – Forecasted and Actual Average On-Peak Effective Temperature (°F) and Effective HDDs for January 24–27, 2005

Forecasted on:	Forecasted for Peak hours on:							
	January 24		January 25		January 26		January 27	
	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD	Eff. Temp. (°F)	Eff. HDD
Jan. 24	10	62	14	54	16	55	21	49
Jan. 25			14	55	13	56	10	59
Jan. 26					13	55	3	67
Jan. 27							1	67
Actual Average	9°F	63	16°F	55	12°F	56	2°F	66

Several regional pipelines issued capacity constraints and operational flow orders for that day. Despite these restrictions and low temperatures, the capacity surplus for the peak hour was 1,926 MW and the peak electricity load was 21,497 MW. Many gas-fired units were off-line or extramarginal for most of the day. Most of the units operating at economic minimum were gas-fired. The total OOM operation for HE 1:00 was 1,594 MW, and it decreased to 583 MW by the

⁶⁰ Compare with Table 1 for December cold period.

peak hour. Total ORC for January 27 was \$1.6 million, with one gas-fired unit receiving most of that payment for providing daily RMR support. There were no VAR or SCR payments on January 27, 2005.

Because the capacity margin remained positive, no Cold Weather Conditions were forecasted, and the markets worked as expected, the report does not review this day in detail.

VII. Conclusions and Recommendations for Action

This report reviews the performance of Appendix H procedures during the winter of 2004–2005, using the examples of two periods characterized by cold weather.

The December 2004 study period did not trigger Appendix H, although the weather was much colder than forecasted. The capacity margin during that period remained positive, and the wholesale electric markets functioned as expected. The large forecast error demonstrated the vulnerability of Appendix H triggers to the weather forecast used to determine Cold Weather Conditions and the seven-day capacity margin. A number of weather-related outages occurred during the period, which suggests that ISO forecasting procedures that incorporate higher levels of expected outages during Cold Weather Conditions are appropriate.

During the January 2005 study period, cold weather resulted in the declaration of a Cold Weather Watch that was later upgraded to a Cold Weather Warning. The resulting cancellation of economic outages and conversion to secondary fuel sources helped to maintain the positive capacity margin, despite numerous capacity constraints and operational restrictions experienced by regional natural gas pipelines. The invocation of Appendix H procedures potentially prevented the declaration of a Cold Weather Event. Unit inflexibility and gas-unit offers below those implied by spot-gas prices contributed to relatively low LMPs during the period. Peak-hour

commitment and dispatch appear to have been remarkably good given the constraints faced by the ISO (e.g., the need for second-contingency coverage and the required operation of resources with Day-Ahead Energy Market commitments).

In general, Appendix H appropriately triggered actions only during the period of most severe weather. This triggering was consistent with high electricity demand, tight reserve margins, and gas-price volatility. The information provisions of Appendix H were helpful. Given the successful operation of the system and markets during periods that were near Cold Weather Conditions, it does not seem that events need to be triggered earlier than the current procedures allow. There also is no indication that the triggers are too sensitive. Because a Cold Weather Event was not declared during winter 2004-2005, it is not possible to evaluate the effects of moving the day-ahead offer submittal deadline.

The implementation and use of Appendix H lead to several modest recommendations:

- The ISO should work with the regional natural gas pipeline companies to unify and streamline the gas industry's electronic bulletin board information and the timely posting of this information to better serve the needs of system reliability.
- When canceling or denying the economic outage of a gas-fired generating unit, the forecast operator should inquire about the unit's ability to procure gas. This will allow the ISO to better assess the availability of the unit.
- The ISO should improve its understanding of the uncertainty surrounding each day's weather forecast and incorporate, as appropriate, these forecast uncertainty estimates in Appendix H definitions of triggering events.
- The ISO should continue efforts to increase real-time offer flexibility to allow gas units to better reflect intra-day gas costs in their offers.

Appendix A—Status of the Actions in the ISO Management Response to the January 2004 Cold Snap Report

In its *Management Response to Cold Snap Report*, the ISO stipulated specific 48 actions to address or implement the recommendations of the *Cold Snap Report*. Out of these, 39 actions were successfully completed, and 9 represent the on-going items. This appendix presents information on the recommended action steps, responsible parties, target completion dates, action status, and utilization update.

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
1	Task the Fuel Diversity Working Group with the Electric/Gas Wholesale Initiative.	ISO & NEPOOL	March 2004	Completed	Yes
2	Form the ISO/NEPOOL Cold Snap Task Force to develop short-term recommendations to enhance electric markets and ensure system reliability for winter 2004/2005.	ISO & NEPOOL	March 2004	Completed	Yes
3	Form the Electric/Gas Operations Committee to facilitate the exchange of near-term operating data between the two industries, in accordance with the NEPOOL Information Policy, FERC Standards of Conduct, and antitrust law compliance.	ISO & Northeast Gas Association	June 2004	Completed	Yes
4	Request Levitan & Associates, Inc. to assess whether the regional pipeline capacity could have been better utilized during the Cold Snap.	ISO & Levitan	March 2004	Completed	Yes
5	Address within the draft <i>RTEP04 Report</i> the need for additional LNG terminals in the Northeast.	ISO	September 2004	Completed	Yes
6	Identify longer-term gas pipeline capacity improvements that would improve electric system reliability.	ISO	1 st Quarter 2005	Completed	Yes
7	Review performance of the forward-reserve market resources during the Cold Snap.	ISO	January 2004	Completed	TBD

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
8	Based on experiences from the Cold Snap, modify input assumptions along with planning and operating procedures prior to winter of 2004–2005.	ISO	August 2004	Completed	Yes
9	Implement short-term electric market fixes as recommended by the Cold Snap Task Force for winter 2004–2005.	ISO	November 2004	Completed	Yes
10	Review designated reserve providers to determine level of reserve actually available during the Cold Snap.	ISO	4 th Quarter 2004	Completed	TBD
11	Distribute letter to NEPOOL participants to remind them of their obligations to report generator outages and reductions on a timely basis.	ISO	October 2004	Completed	Yes
12	Discuss appropriate outage-notification and sanctions policies with the NEPOOL Reliability Committee.	ISO	November 2004	Completed	Yes
13	Conduct meetings with regional gas pipeline companies to explore the development of new gas services for gas-fired units, in conjunction with potential changes to structure of the electric market.	ISO	March 2004	Completed	Yes
14	Solicit proposals from the regional gas pipeline companies for new products and services.	ISO	1 st Quarter 2004	Completed ⁶¹	Yes
15	Evaluate new or incremental natural gas products and services. If deemed applicable, develop the necessary changes to existing market rules to take advantage of any new natural gas products and services.	ISO	1 st Quarter 2005	Completed ⁶²	No ⁶³

⁶¹ *Assessment of “Peaking Gas” Service for New England’s Quick-Start Generators*, Herbert Rakebrand and Associates, LLC, April 1, 2005. The document is available at http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/6_Peaking_Gas_Service_Assessment.pdf

⁶² Ibid.

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
16	Review the additional amount of capacity that could have been on-line during the Cold Snap if dual-fuel switching was 100% efficient.	ISO	February 2004	Completed	Yes
17	Conduct meetings with New England air regulators to review permitting restrictions on dual-fuel units.	ISO	May-November 2004	Ongoing	Yes
18	Engage an environmental consultant to assist the ISO in its efforts to address dual-fuel issues.	ISO	4 th Quarter 2004	Completed ⁶⁴	Yes
19	Engage an environmental consultant to develop an inventory of air permits for all dual-fuel units. Investigate the air-permit limitations on burning both primary and secondary fuel sources.	ISO	4 th Quarter 2004	Completed ⁶⁵	Yes
20	Establish a new operating procedure that triggers a request for all primary gas-fired dual-fuel units to switch to secondary liquid fuel oil during Cold Weather Events.	ISO	October 2004	Completed	Yes
21	Consult with and provide status reports of all Cold Snap initiatives to the New England Governors' Conference Power Planning Committee.	ISO	Ongoing	Ongoing	Yes
22	Conduct site visits of both existing and potential dual-fuel units to identify what barriers exist to obtaining full dual-fuel operability.	ISO	3rd Quarter 2005	Ongoing ⁶⁶	TBD

⁶³ After reviewing the results of *Assessment of "Peaking Gas" Service for New England's Quick-Start Generators*, the ISO determined that no new or incremental natural gas products or services will be offered until the regional gas supply situation changes significantly. Therefore, the ISO determined that there was no need, at this time, to change the existing market rules and procedures.

⁶⁴ *Dual-Fuel Generating Capacity and Environmental Constraints Analysis Interim Report*, ESS Group Inc., April 1, 2005. The document is available at http://www.iso-ne.com/special_studies/January_14_-_16_2004_Cold_Snap_Reports/8_Dual_Fuel_Interim_Report/

⁶⁵ Ibid.

⁶⁶Ibid.

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
23	Develop economic incentives to encourage greater generating availability during times of peak demand or reserve shortage conditions.	ISO	August 2004	Completed ⁶⁷	TBD
24	Address seams issues relating to unit availability and capacity markets with other ISOs.	ISO	Ongoing	In progress	TBD
25	Provide the ISO forecast department with information regarding gas-fired generator transportation contracts and the capability to verify fuel nominations and scheduled volumes.	ISO	September 2004	Completed ⁶⁸	Yes
26	Provide the ISO forecast office with access to the regional interstate pipelines' electronic bulletin boards to obtain real-time operational information.	ISO	August 2004	Completed	Yes
27	Based on the experiences from the Cold Snap, modify the input assumptions and forecasting/operating procedures prior to winter 2004–2005.	ISO	August 2004	Completed	Yes
28	Follow up with those generating units that experienced cold weather-related outages during the Cold Snap to ensure that remedial actions have been taken to prevent further occurrences.	ISO	August 2004	Completed	Yes
29	Align the timing of the wholesale electric markets to the natural gas market during severe cold weather or equivalent emergency events.	Cold Snap Task Force	November 2004	Completed	Yes
30	Investigate allowing increased flexibility for generator offers within the energy market.	ISO	4 th Quarter 2005	In progress	TBD
31	Investigate rule changes necessary to better reflect in LMPs the cost of units dispatched out-of-merit.	ISO	4 th Quarter 2005	In progress	TBD

⁶⁷ LICAP project

⁶⁸ Contract database was created by Merimack Energy.

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
32	Revise internal system operating procedures to ensure economic outages are not granted after the defined notification deadlines.	ISO	September 2004	Completed	TBD
33	Modify OP 5 to tighten generator notification responsibilities with respect to economic outages.	ISO	October 2004	In progress	TBD
34	Implement a new operating procedure that will trigger the elimination and cancellation of economic outages during a projected Cold Weather Event.	ISO	October 2004	Completed	Yes
35	Review the necessity of economic outages with the NEPOOL Markets Committee.	ISO	March 2005	Completed	TBD
36	Review existing operating procedures for clarification of transmission operation under extreme conditions.	ISO	February 2004	Completed	TBD
37	Within RTEP04, assess transfer capabilities and generation fuel mix within transmission-constrained load pockets under extreme demand conditions.	ISO	August 2004	Completed	Yes
38	Modify operating guides to ensure maximum transfer capabilities are utilized under both normal and emergency operating conditions.	ISO	January 2004	Completed	TBD
39	Investigate dynamic re-dispatch procedures with external control areas to enable higher import/export capabilities between control areas.	ISO	2 nd Quarter 2005	On-going	TBD
40	Develop a "Best Practices" process for transmission rating and transfer capability calculations to optimize import capabilities during emergencies.	ISO	2 nd Quarter 2005	On-going	TBD
41	Investigate modifications to existing market rules regarding real-time deviation penalties.	ISO	March 2005	Completed	TBD
42	Determine the additional amount of capacity that could have been online if the regional gas pipelines had increased line-pack on their systems prior to the Cold Snap.	ISO	March 2004	Completed	Yes

Action Number	Action Step	Responsible Party	Target Completion Date	Status	Utilized
43	Review and revise, as necessary, the established procedures and protocols for communicating with state officials and regulatory agencies during periods of high demand or abnormal conditions.	ISO	May and December 2004	Completed	Yes
44	Incorporate “lessons learned” from the Cold Snap into the MMD’s review of future events.	ISO	May 2004	Completed	TBD
45	Review and update, as necessary, information transfer with FERC’s Office of Market Oversight and Investigations and state and other regulators.	ISO	March 2004	Completed	TBD
46	Develop a non-disclosure agreement between the ISO and the natural gas pipeline companies to assure information transfer.	ISO	July 2004	Completed	No
47	Execute non-disclosure agreements with the regional gas companies participating on the EGOC.	ISO	4 th Quarter 2004	Completed	No
48	Review the NEPOOL information policy to determine the requirements that govern information sharing during the look-ahead meetings between the ISO and gas pipelines.	ISO	September 2004	Completed	Yes

Appendix B—Events in the Regional Natural Gas Markets

The table below presents a timeline of events in the regional natural gas market for January 16–28, 2005. Please note all times are referenced to Eastern Standard Time (EST). The information shown below is compiled from a mixture of anticipated notices, final end-of-day notices, and new postings from the electronic bulletin boards of several of the regional interstate natural gas pipelines.

Date	Time	Events
1/15/05	1:21:26 p.m.	Algonquin issues capacity constraint for 1/16: <ul style="list-style-type: none"> o No due shipper gas on Algonquin. o Algonquin restricts all AIT-1 and a portion of priority 3 nominations for gas flowing through Stony Point compressor station. o No incremental nominations through Stony Point, NY.
	2:20:00 p.m.	Tennessee issues capacity constraint for 1/16: <ul style="list-style-type: none"> o Flow restrictions through Station 245 (East Windfield, NY) and through Station 314 (Main Line Valve 314).
1/16/05	2:05:00 p.m.	Tennessee issues capacity constraint for 1/17: <ul style="list-style-type: none"> o Flow restrictions through Station 245 (East Windfield, NY) and Station 321 (Uniondale, PA).
	2:27:40 p.m.	Algonquin issues capacity constraint for 1/17: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts a portion of priority 3 nominations for gas flowing through Stony Point compressor station. o No incremental nominations through Stony Point, NY.

Date	Time	Events
1/17/05	1:46:06 p.m.	Algonquin issues capacity constraint for 1/18: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts a portion of priority 3 nominations for gas flowing through Stony Point compressor station. o No incremental nominations through Stony Point, NY.
	2:35:00 p.m.	Tennessee issues capacity constraint for 1/18: <ul style="list-style-type: none"> o Flow restrictions through Station 245 (East Windfield, NY) and Station 321 (Uniondale, PA).
	3:50:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/17: <ul style="list-style-type: none"> o Tennessee not accepting nominations for withdrawal increases from Egan Storage (located near Evangeline in Acadia Parish, Louisiana) issued for remainder of 1/17 gas day.
1/18/05	9:25:00 a.m.	New Notice: Tennessee revises capacity constraint for 1/18: <ul style="list-style-type: none"> o Tennessee not accepting increases in Park/Loan nominations for remainder of gas day 1/18 gas day.
	10:00:00 a.m.	Iroquois issues capacity constraint for 1/18–1/21: <ul style="list-style-type: none"> o No due shipper gas on Iroquois. o Shippers and point operators requested to remain in balance daily.
	2:35:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/18: <ul style="list-style-type: none"> o Bump/Restriction–57% of excess AOT and no Cycle 1(C1) increases for secondary out-of-path supply-aggregation nominations for withdrawal volumes received at Egan Storage for remainder of gas day.
	3:00:00 p.m.	Tennessee Operational Flow Order (OFO) goes into effect for Zones 5 and 6 (Northeast Region): Critical Day 1 OFO effective 1/19/05 at 9:00 a.m. CCT for LMS-MA Balancing in Zones 5 & 6: <ul style="list-style-type: none"> o Daily discrepancies between scheduled deliveries and actual flows required to not exceed the greater of 1,000 decatherms (dths) or 2% of actual quantities. A penalty of \$5.00 plus the applicable Regional Daily Spot Price per dth will be assessed on overtakes.

Date	Time	Events
	1:31:42 p.m.	Algonquin issues capacity constraint for 1/19: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts a portion of priority 3 nominations for gas flowing through Stony Point compressor station. o No incremental nominations through Stony Point, NY.
	3:35:00 p.m.	Tennessee issues capacity constraint for 1/19: <ul style="list-style-type: none"> o Flow restrictions through Station 245 (West Windfield, NY) and Station 321 (Uniondale, PA). o OFO remains in effect.
	3:35:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/19: <ul style="list-style-type: none"> o Tennessee not accepting increases in Park Withdraws/Loan and no increases in scheduled IS-PA Withdraw, IS-MA Withdraw, and FS-AO Withdraw nominations for the gas day 19th system wide.
1/19/05	1:20:11 p.m.	Algonquin issues capacity constraint for 1/20: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts all AIT-1 and a portion of priority 3 nominations for gas flowing through Stony Point compressor station. o No incremental nominations through Stony Point, NY.
	3:05:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/19: <ul style="list-style-type: none"> o Flow restrictions (no increases through) Station 336 (pipeline point P00095).
	4:15:00 p.m.	Tennessee issues capacity constraint for 1/20: <ul style="list-style-type: none"> o Flow restrictions on the Leidy meters and Central Texas Gathering System including the Wharton meter. In addition, no increases in Supply to Market for Secondary out-of-the-Path nominations pathed through Station 245 and Station 321. o OFO remains in effect.
	5:19:27 p.m.	Algonquin revises capacity constraint for 1/19: <ul style="list-style-type: none"> o Restriction of delivery nominations at Tennessee Gas Mahwah for the remainder of the gas day.

Date	Time	Events
	10:45:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/20: <ul style="list-style-type: none"> o Flow restrictions lifted for services pathed through the Leidy meters for C1 gas day of 1/20.
1/20/05	9:05:00 a.m.	New Notice: Tennessee revises capacity constraint for 1/20: <ul style="list-style-type: none"> o No increases in interruptible services pathed through Station 336 (pipeline point P00095) for the remainder of the gas day.
	10:00:00 a.m.	Iroquois revises capacity constraint, new end date 1/26: <ul style="list-style-type: none"> o No unscheduled due shipper gas on Iroquois (Allowing ‘scheduled’ due shipper gas (i.e., loans, OBAs) but not unauthorized overruns.) o Shippers and point operators requested to remain in balance daily.
	1:00:33 p.m.	Algonquin issues capacity constraint for 1/21: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts all AIT-1 and a portion of priority 3 nominations for gas flowing through Hanover compressor station. o No incremental nominations through Hanover, NJ.
	2:15:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/20: <ul style="list-style-type: none"> o No nomination increases pathed through Station 336 (pipeline point P00095) for the remainder of the gas day 1/20.
	2:45:00 p.m.	New Notice: Tennessee revises capacity constraint for 1/20: <ul style="list-style-type: none"> o Flow restrictions on the Leidy meters effective C1 Restricted 64% of newly increased Secondary out of Path; Supply-to-Market nominations.

Date	Time	Events
	3:15:00 p.m. 5:30:00 p.m.	Tennessee issues capacity constraint for 1/21: <ul style="list-style-type: none"> o Flow restrictions on Station 47 (producing region, pipeline point P00033). o End-of-Day Notice: Restricted 100% Supply-to-Market IT through Stations 47; 34% Supply-to-Market, Secondary out-of-the-Path through Station 336; No Supply-to-Market, Secondary out-of-the-Path nomination increases through Central Texas Gathering System, Station 245, and Station 321. o OFO remains in effect.
1/21/05	12:55:22 p.m.	Algonquin issues capacity constraint for 1/22: <ul style="list-style-type: none"> o Shippers and point operators requested to remain in balance daily. o No due shipper gas on Algonquin. o Algonquin restricts all AIT-1 and a portion of priority 3 nominations for gas flowing through Hanover compressor station. o No incremental nominations through Hanover, NJ.
	2:25:00 p.m. 5:10:00 p.m.	Tennessee issues capacity constraint for 1/22: <ul style="list-style-type: none"> o Flow restrictions on Station 47 (producing region, pipeline point P00033). o OFO remains in effect. o End-of-Day Notice: Restricted 100% Supply-to-Market IT through Stations 47; No Supply-to-Market, Secondary out-of-the-Path nomination increases through Central Texas Gathering System, Station 245, Station 321, and Station 336.
1/25– 28/05		Tennessee continued OFO, and Tennessee and Algonquin continued flow restrictions.
1/28/05	2:20:00 p.m.	Tennessee issues Critical Day OFO lifted, effective January 29, 2005, at 9.00 a.m.

As of January 25, 2005, Tennessee continued OFO, and Tennessee and Algonquin continued flow restrictions.

Appendix C—Change of Rules by Rhode Island and Dual-Fuel Performance during the Winter 2004–2005

One of the action items defined by the *January 2004 Cold Snap Report* was to assess the regulatory barriers, if any, that impact the ability of dual-fuel units to operate on secondary fuel (presumably, liquid fuel oil) during such extreme winter weather events. This action item had several objectives:

- to gather information on the true ability of each permitted and equipped dual-fuel resource to switch from its primary fuel, natural gas, to its secondary fuel
- to work with the New England air regulators to determine if it were possible to modify or clarify air permits in any way to improve bulk power system reliability during periods of extreme winter weather
- to explore the state emergency procedures that might be utilized, consistent with real-time operations, to access permit-constrained generation under extreme emergency conditions

The ISO staff held several meetings with New England’s state air regulators during 2004 to undertake this action item. With their help, the ISO compiled a comprehensive database that includes details of the air permits for all fossil-fueled resources in the region. This was very helpful in determining how to approach expanding regional dual-fuel capability. In addition, this information provided a basis for identifying which generating resources had the potential to improve the reliability of the electric power system, in the near-term, by modifying their air-permits prior to the winter of 2004–2005.

Previously, the air permits issued in Rhode Island focused on the availability (or unavailability) of natural gas as the trigger mechanism for allowing the generator to switch to its secondary fuel. After discussions with the Rhode Island Department of Environmental Management (RIDEM), changes were initiated to revise the air permits for Manchester Street

Station that would allow the station to switch to its secondary fuel when the ISO implements certain actions outlined in Appendix H.⁶⁹

⁶⁹ The permit allows units to convert to a secondary fuel in the case of a Cold Weather Warning and invocation of OP 4 actions for the same day, or a Cold Weather Event declaration. However, during the winter of 2004–2005, no conditions triggered this permit clause, since no OP 4 conditions took place during Cold Weather Conditions, and no Cold Weather Event occurred.