

**Summary Investigation**

**Into the Aquidneck Island Gas Service Interruption of January 21, 2019**

**Investigation Report**



**October 30, 2019**

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## Executive Summary

On January 21, 2019, at approximately 6:50 pm<sup>1</sup> The Narragansett Electric Company, Inc., (Narragansett Electric) known to its customers as National Grid,<sup>2</sup> shut down a significant portion of its natural gas distribution system in Newport and Middletown on Aquidneck Island, resulting in a gas service outage to 7,455 customers. The impact of the seven-day outage led Governor Gina M. Raimondo to declare a state of emergency in Newport County.<sup>3</sup>

On January 30, following restoration of gas service, the Division of Public Utilities and Carriers (Division) opened a “Summary Investigation” pursuant to §39-4-13 of Rhode Island General Laws to identify the causes of the outage and to assess any other matters related to gas capacity or supply constraints on Aquidneck Island. This Report provides the Division’s investigation findings, identifies alleged violations of Rhode Island gas safety rules and describes a series of recommendations to enhance gas distribution reliability on Aquidneck Island and across Rhode Island.

## Precipitating Factors in the Low-Pressure Condition on the Gas System

The gas service outage on Aquidneck Island was the result of a low-pressure condition on the “G-System” branch of the Algonquin pipeline, the portion of the interstate natural gas pipeline that serves Aquidneck Island and much of Rhode Island owned and operated by Enbridge, Inc. The low-pressure condition was the result of three separate precipitating factors that each contributed to cause the low-pressure condition. Those three precipitating factors that occurred on the morning of January 21<sup>st</sup> were as follows:

- Demand for natural gas was in excess of contractual limits by many of Algonquin’s customers along the Algonquin G-System, driven by sudden low temperatures;
- The uninterruptible power system at the liquified natural gas storage and vaporization facility at Fields Point in Providence, owned and operated by National Grid LNG, failed, shutting down the vaporizers and causing a sudden and very large increase in demand for gas from the Algonquin pipeline into the Providence area;

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<sup>1</sup> All times stated in this Report are Eastern Standard Time, unless otherwise specifically indicated.

<sup>2</sup> Narragansett Electric is a wholly owned subsidiary of National Grid USA. See infra page 11.

<sup>3</sup> Throughout the service outage first-responders from the National Guard, Rhode Island Emergency Management Agency, state and local law enforcement, and fire departments aided Aquidneck Island communities. The Division wishes to acknowledge their contribution to public safety.

demand that would otherwise have been met by vaporized LNG from the Fields Point facility;

- A valve located on the Algonquin pipeline at a meter station in Weymouth, Massachusetts operated by Enbridge malfunctioned. The malfunction stemmed from a programming error that caused the valve to repeatedly open and close restricting the flow of gas when the system operators attempted to inject more into the Algonquin pipeline that feeds gas into the G-System.

The Report, in concert with an accompanying report from the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA), finds that each of these three precipitating factors needed to occur in order to produce the low-pressure condition that ultimately led to the gas service outage.

Had Algonquin programmed its valve in Weymouth correctly, modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment. As the provider of interstate gas transportation, Algonquin had a duty to program its meters and valves correctly to assure safe and reliable service to its customers. But, in this case, it failed to do so. Similarly, the National Grid LNG shutdown of its LNG vaporization facility, due to a failed uninterruptible power supply that caused the plant's vaporizers to fail, contributed to the low-pressure condition. According to PHMSA, National Grid LNG experienced an emergency shutdown in November 2018 due to a failed uninterruptible power supply which it did not adequately investigate or resolve. Had National Grid LNG taken steps to address the faulty uninterruptible power supply modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment.

#### Forecasting and Planning Errors of Narragansett Electric

Regardless of the cause of the low-pressure condition, the ability of Narragansett Electric to respond to the failures at the Weymouth meter station and the Providence LNG facility once they had occurred was significantly limited by its management of the gas distribution system over the previous several years. Narragansett Electric through its decisions created preconditions that significantly contributed to the outage. In particular:

- Narragansett Electric had deactivated its permanent LNG storage and vaporization facility located in Newport in 2010. As demand on the island grew year by year, the Company failed to forecast the need to redeploy LNG to address load growth. Similarly, Narragansett Electric did not deploy temporary LNG vaporization facilities at Portsmouth during the winter of 2018-2019. Narragansett Electric made these decisions based on erroneous forecasting assumptions.
- Narragansett Electric did not engage in contingency planning on its distribution system despite having experienced a similar low-pressure condition on March 7, 2014.

As important as the precipitating factors were, the planning and forecasting errors of Narragansett Electric made the distribution system vulnerable to the effects of a low-pressure condition and a widespread service outage. Based on almost a decade of gas system operational decisions, Narragansett Electric concluded that it did not need to have LNG vaporization capability on Aquidneck Island. Had Narragansett Electric installed backup LNG vaporization, the gas distribution pressure could have survived the low-pressure condition without an outage by supplementing Aquidneck Island with vaporized LNG. Similar to the duty of Algonquin, Narragansett Electric had a duty to forecast accurately, to plan appropriately, and to deploy assets to address foreseeable contingencies.

#### Additional System Vulnerabilities

In addition to the specific causes of the January 21 outage, the Report identifies a series of vulnerabilities that did not contribute to the outage of last winter but present a future vulnerability to the gas system which Narragansett Electric should address. In particular:

- Narragansett Electric lacked a mapping and tracking process to manage outage reports;
- Narragansett Electric did not have a viable plan to sectionalize its gas system as an emergency preparedness measure;
- The National Grid organization manages Narragansett Electric's gas business through an organizational structure that does not have a Rhode Island-based senior executive to direct gas operations;

- Narragansett Electric and National Grid LNG did not conduct an appropriate after-action review and did not provide a report of its review to the Division or to federal regulators. In fact, the Company did not inform the Division of the failure of the vaporizers at the Providence LNG facility until 39 days after the event.

#### Recommendation for Denial of Cost Recovery by Narragansett Electric

Based on the findings of the Report, the Division has identified sufficient grounds for it to oppose recovery of over \$25 million in costs incurred by Narragansett Electric. The Division will recommend that the shareholders of Narragansett Electric and Enbridge, not Rhode Island's gas customers, bear the costs of the gas outage and restoration. The final determination of any cost recovery, should Narragansett Electric seek it, would be made by the Public Utilities Commission. The Report takes no position on how these costs should be allocated between Enbridge and National Grid through civil litigation. In addition, the Division will issue a Notice of Probable Violation to Narragansett Electric for a violation of Division gas regulations pertaining to a failure to notify the Division of the shutdown at the Providence LNG facility on January 21, 2019.

#### Recommendations for Gas System Improvements

- (1) Improve gas long-range Planning;
- (2) Deploy LNG facilities on Aquidneck Island;
- (3) Evaluate reinforcement of the Algonquin lateral pipeline serving Portsmouth;
- (4) Implement demand response initiatives on Aquidneck Island;
- (5) Conduct scenario-based contingency and emergency response planning;
- (6) Evaluate the feasibility of sectionalized gas districts in Newport;
- (7) Establish a process for emergency mobilization of LNG;
- (8) Create an outage mapping and tracking process;
- (9) Conduct an after-action review process;
- (10) Improve communications between Narragansett Electric and Algonquin;
- (11) Appoint a Vice President to supervise the gas business for Rhode Island;



- (12) Implement the recommendations of the PHMSA report on this incident.

### Conclusions

Over 250,000 Rhode Island families and businesses depend on natural gas to heat and operate the buildings in which they work, live and sleep. For most of these customers, natural gas is their only fuel option. The recommendations of this Report will enhance the reliability of winter heat for gas customers and will ensure that the customers of Narragansett Electric and Enbridge are not financially responsible for the outage.

## **Investigation Process Note**

This Report is the final product of an investigation undertaken by the Rhode Island Division of Public Utilities and Carriers (Division), pursuant to its authority under §39-4-13 of the Rhode Island General Laws.<sup>4</sup> The statute authorizes the Division to “summarily investigate” matters prescribed in that section of the law, including issues relating to public safety, the quality or adequacy of service of any public utility, or “any matter relating to a public utility.”

On January 30, 2019, then Deputy Administrator Kevin Lynch notified The Narragansett Electric Company, Inc. (Narragansett Electric) that the Division had opened an investigation of the gas service interruption on Aquidneck Island. Mr. Lynch, who became Interim Administrator of the Division in February 2019, assigned Jonathan Schrag, Deputy Administrator, the role of Investigative Lead and John Spirito, Chief Legal Officer, the role of Hearing Officer and arbiter of any procedural legal issues. Consistent with precedent in Division investigations, neither John Spirito nor Interim Administrator Lynch participated in any substantive part of the investigation, remaining in reserve to decide any matter, violation, or request for regulatory order the investigation might produce, pursuant to §39-4-14 of Rhode Island General Laws.<sup>5</sup> Shortly before the completion of this Report, Mr. Lynch left the Division to pursue another government position and Linda George was appointed Interim Administrator. Ms. George similarly remained separate from the investigation to preserve her impartiality.

To perform the investigation, Deputy Administrator Schrag assembled an investigation team. The team included: Ron Gerwatowski, Senior Regulatory Advisor to the Division,<sup>6</sup> as the lead coordinator; Leo Wold, Deputy Chief of Legal Services for the Division; and Alberico Mancini, Deputy Chief Public Utility Accountant for the Division. In addition, pursuant to §39-1-19 the Division relied on the Office of the Attorney General Public Utilities Regulatory Unit to represent the Division. For gas technical expertise, the Division hired two expert consultants on natural gas matters: Greg Lander, President of Skipping Stone, LLC who provided expertise relating to interstate pipeline matters; and Rod Walker, CEO/President of Rod Walker &

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<sup>4</sup> See: <http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-4/39-4-13.HTM>

<sup>5</sup> § 39-4-14 states: “If, after making a summary investigation, the division becomes satisfied that sufficient grounds exist to warrant a formal hearing being ordered as to the matters so investigated, it shall furnish to the public utility interested, a statement notifying the public utility of the matters under investigation. Ten (10) days after the notice has been given, the division may proceed to set a time and place for a hearing and investigation.”

<sup>6</sup> Mr. Gerwatowski works for the Division through a consultancy contract.

Associates, who provided expertise on gas distribution system operations. The Division relied upon the advice and expertise of these natural gas experts for the technical conclusions in this Report.

The Division conducted its investigation through multiple rounds of written requests for information and data from Narragansett Electric, as well as interviews with Narragansett Electric employees. The Division received over 200 written responses to questions and many files containing operational data. In total, the Division reviewed over 5,000 pages of information from the Company. The Division also held five interviews with Narragansett Electric employees to orally examine designated topics related to the outage. At these meetings, the employees had an opportunity to present their views.

Throughout its investigation, the Division worked in close cooperation with the Pipeline and Hazardous Materials Safety Administration (PHMSA) – the agency of the U.S. Department of Transportation that oversees pipeline and liquefied natural gas (LNG) safety. PHMSA has direct regulatory authority over interstate pipelines, including the operations of Enbridge, the owner of Algonquin Gas Transmission, LLC that operates an interstate pipeline providing service to Rhode Island. PHMSA also has direct authority over gas safety and maintenance matters, including the operations of National Grid LNG, LLC, a distinct, federally regulated and wholly-owned subsidiary of National Grid USA, which owns the LNG storage facility located at Fields Point in Providence.<sup>7</sup> The Division relied on PHMSA for information that PHMSA obtained directly from Enbridge and National Grid LNG, LLC. The Division and PHMSA investigation teams collaborated through regular telephone conferences and a two-day in-person meeting in Rhode Island. PHMSA will issue its own report consistent with the scope of its regulatory authority. Throughout the investigation PHMSA and the Division exchanged information and the reports of the two agencies are intended to be read in concert with each other.

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<sup>7</sup> There is a provision in Title 39 of Rhode Island General Laws which states that there is a statutory presumption of state jurisdiction over the use of any liquefied natural gas within the borders of the state. See §39-1-2.2. However, the provision lacks specificity. In contrast, the owner of the Providence LNG facility is regulated directly by federal authorities under laws and regulations that are specific and wide in scope. The existence of this federal authority raises technical legal questions about the doctrine of federal preemption which holds that if there is a conflict between state and federal authority, the federal rule prevails. See *Verizon New England Inc. v. Rhode Public Utilities Commission*, 822 A.2d 187, 192 (R.I. Sup. Ct., 2003) (“The Supremacy Clause of the United States Constitution, Article VI, clause 2, preempts or invalidates state law that interferes or conflicts with federal law.”). The Division does not concede the applicability of the preemption rule here and reserves all of its rights.

The Hearing Officer issued a protective order that set forth the confidentiality parameters of the investigation, consistent with Rhode Island General Laws §38-2, the Access to Public Records Act (APRA).<sup>8</sup> The Division’s investigation and all information accumulated during the pendency of the investigation were treated confidentially, in accordance with the provisions of APRA.<sup>9</sup> With the completion of the summary investigation through the issuance of this Report, the records specifically relied upon for the conclusions in this Report are public, unless there is an APRA exemption that applies. For the convenience of the public, this Report includes an Appendix that contains copies of the key records relied upon, as cited in the footnotes to the Report.<sup>10</sup>

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<sup>8</sup> See <http://webserver.rilin.state.ri.us/Statutes/TITLE38/38-2/INDEX.HTM> A copy of the protective order is provided at the end of the Appendix to this Report.

<sup>9</sup> All materials during the investigation are exempted from public disclosure as “investigatory records” pursuant to §38-2-2(4)(P). The applicable exemption is defined as: “All investigatory records of public bodies, with the exception of law enforcement agencies, pertaining to possible violations of statute, rule, or regulation other than records of final actions taken, provided that all records prior to formal notification of violations or noncompliance shall not be deemed to be public.”

<sup>10</sup> As indicated in the Appendix, there are a limited number of records or sections of records that remain exempt from public disclosure pursuant to other APRA exemptions, such as critical energy infrastructure information, personal or customer-specific information, and materials claimed as proprietary by Narragansett Electric.

## **National Grid Group Corporate Naming Structure**

In Rhode Island, the utility providing gas service is recognized under the corporate name and logo of “National Grid.” Yet, as a legal and corporate matter, the actual corporate entity regulated by the Public Utilities Commission and the Division is “The Narragansett Electric Company” (Narragansett Electric) which does business under the brand name of “National Grid.” Narragansett Electric is a subsidiary in the chain of corporate entities that begins with the London-based parent company, “National Grid plc.”

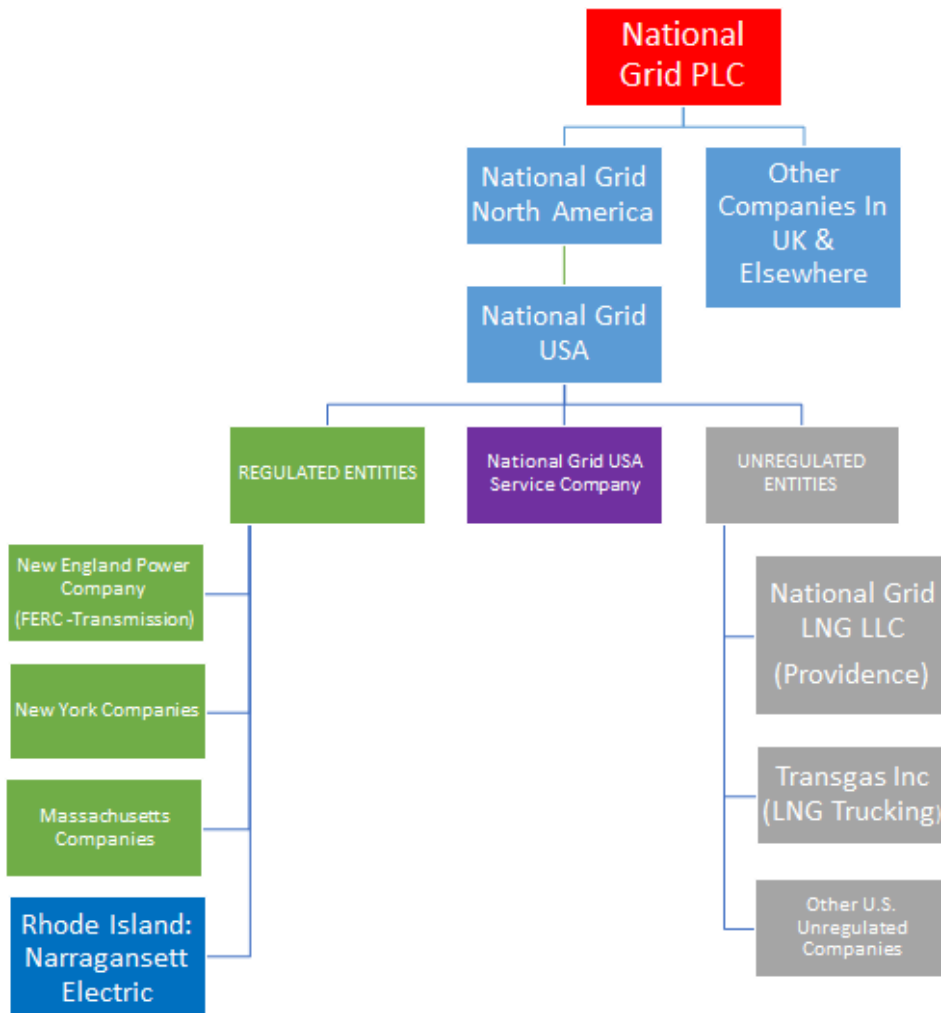
Because numerous subsidiaries under “National Grid plc” do business under the brand name of “National Grid,” it can cause confusion when more than one company in the National Grid corporate family is involved in a single matter. For that reason, this Report will use the formal legal name of the Rhode Island entity The Narragansett Electric Company, Inc. (Narragansett Electric) when describing most of the events. Throughout this Report, the terms “Narragansett Electric” and “the Company” refer to the Rhode Island public utility regulated by the Division and the Commission. When the Report describes other specific National Grid corporate entities, it will use their formal names to avoid confusion.<sup>11</sup>

Below is a simplified corporate organization chart which is designed to illustrate the structure. The chart is not comprehensive and leaves out numerous separate corporations. For example, there are several separate regulated companies in the states of Massachusetts and New York, as well as numerous other entities in Europe and elsewhere. For purposes of the chart, they are bundled in one box each for each state and one box for the other international companies. Numerous other entities are not shown. While the chart is simplified, it is designed to illustrate the structure starting with the London-based parent and cascading down to the companies in the United States. As the chart also indicates, there are both regulated and unregulated entities in the corporate family. This distinction is important for reasons that are addressed in subsequent sections of the Report. The chart is provided here to assist the reader.<sup>12</sup>

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<sup>11</sup> While this Report attempts to draw the corporate distinctions, the responses to the Division’s data requests from Narragansett Electric do not always do the same. Many of the written responses tend to use the term “Company” and “National Grid” quite liberally, without clear distinctions between the separate entities.

<sup>12</sup> More information about the numerous entities are available at the following National Grid plc website: <https://investors.nationalgrid.com/debt-investors/group-structure>



**Figure 5:** Simplified Illustration of National Grid Corporate Structure – from U.K Parent down to U.S. entities.

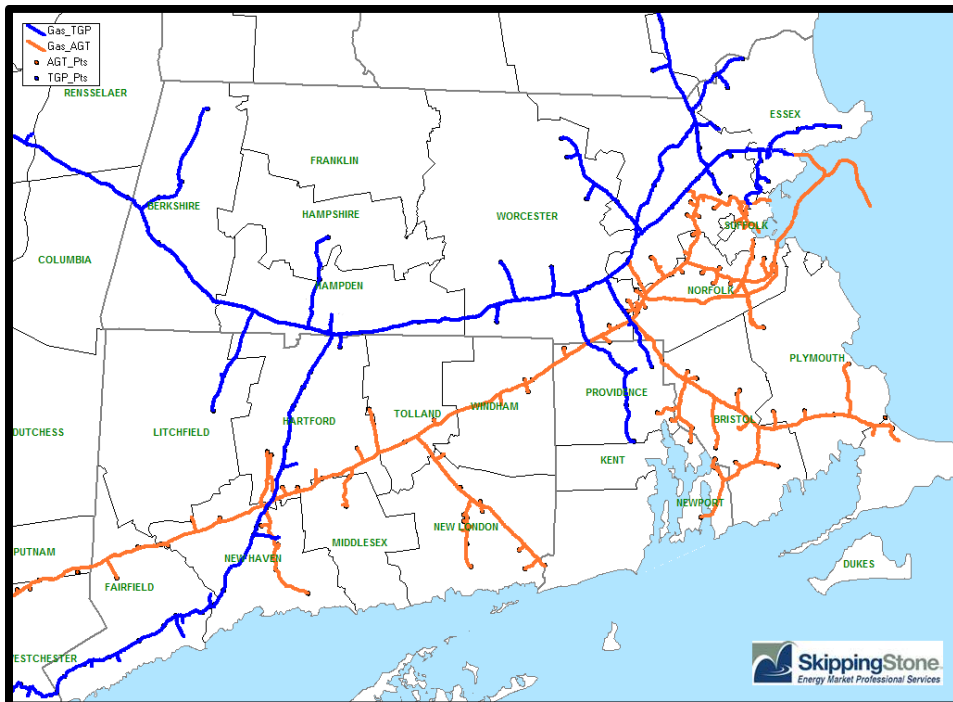
## **Section 1.0: The Natural Gas Systems**

The events of January 21, 2019 occurred within a complex set of natural gas pipeline systems serving Rhode Island. This section provides information about the structure of these pipeline systems as they affected the events of January 21, 2019.

### **1.1 The Interstate Gas Systems Serving Rhode Island**

The general configuration of the natural gas pipeline systems that serve Rhode Island consist of two types of systems. One is the interstate pipeline system that transports gas across state lines and the other is the local gas distribution system confined to Rhode Island that is owned by Narragansett Electric.

The map in Figure 2 shows the two interstate pipelines that deliver natural gas into Rhode Island. One is the Tennessee Gas Pipeline system owned by Kinder Morgan, shown in blue. The other is the Algonquin Gas Transmission system (Algonquin) owned by Enbridge LLC (Enbridge), shown in orange.



**Figure 2.** Map showing the Algonquin pipeline (orange) and Tennessee Gas Pipeline (blue)

Each of the interstate pipelines delivers gas to Local Distribution Companies (“LDCs”) and direct-connected end-users<sup>13</sup> at receipt points known as “take stations.”<sup>14</sup> The take stations are both the physical and jurisdictional demarcations between the interstate pipelines, which are regulated by federal authorities including PHMSA and the Federal Energy Regulatory Commission (FERC), and the intrastate gas distribution system that is regulated by the State of Rhode Island through the Division of Public Utilities and Carriers and the Public Utilities Commission.

The Algonquin Gas Transmission (“Algonquin”) system, owned by Enbridge delivers gas to Aquidneck Island and was the interstate pipeline system most directly involved in the outage of January 21. The Algonquin mainline begins with an interconnection at the Texas Eastern Transmission System in New Jersey,<sup>15</sup> runs through New York and Connecticut, across the northwest tip of Rhode Island, and into Massachusetts, ultimately interconnecting with the Maritimes & Northeast Pipeline<sup>16</sup> north of Boston.

One of the main branches of the Algonquin system in New England, referred to as the G-System, branches south from the mainline near Mendon, Massachusetts to provide gas service to southeastern Massachusetts and Rhode Island.<sup>17</sup> The G-System delivers gas to Providence and eventually onward to Aquidneck Island. The G-System is the subsystem of Algonquin on which the low-pressure condition causing the outage on Aquidneck Island occurred.

Typically, most of the natural gas delivered into Rhode Island on the Algonquin system follows a path from southwest to northeast. But, the Algonquin mainline can be supplemented with deliveries from the north to the south through a branch that connects to the Maritimes & Northeast pipeline which extends from Canada to the Boston area. This branch of the Algonquin system is referred to as the I-System. In the middle of the I-System is a metering and valve station at Weymouth, Massachusetts which controls the flow of gas from northern supply areas in Canada as well as, when present, off-shore LNG tankers capable of vaporizing LNG into the I-System<sup>18</sup>.

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<sup>13</sup> In New England, direct-connected end-users are primarily natural gas fired power plants that generate electricity.

<sup>14</sup> In industry parlance, “take stations” also are referred to as “gate stations” and “M&R stations.” In this Report we will use the term take station. From the pipeline’s perspective a take station is a delivery point; while from the gas distribution company’s perspective it is a receipt point.

<sup>15</sup> The Algonquin system also receives gas from other interstate pipelines, including Transcontinental Gas Pipeline, Columbia Gas Transmission, Tennessee Gas Pipeline, Millennium Pipeline, and Iroquois Gas Transmission.

<sup>16</sup> Both of the Texas Eastern Transmission and Maritimes and Northeast pipelines are also owned and operated by Enbridge. In this report, these two lines will be referred to by their operating names and not as Enbridge.

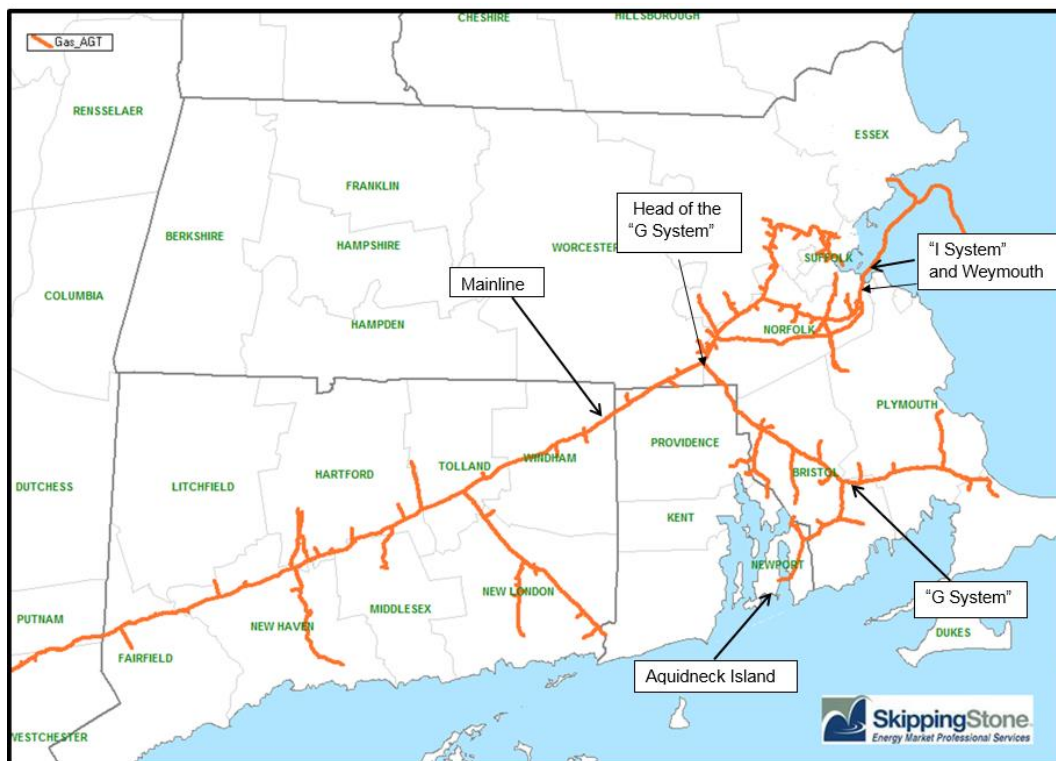
<sup>17</sup> There are various subsystems off the Algonquin mainline system that are identified with letters.

<sup>18</sup> On January 21, 2019 there was an LNG Tanker that was vaporizing LNG into the I-System.



This Weymouth metering station was one of the precipitating factors of the low-pressure condition on January 21, 2019.

For reference, the map in Figure 3 shows the Algonquin system and marks the location of the mainline, G-System, the I-System, Aquidneck Island and the Weymouth meter station.



**Figure 3:** Map identifying relevant areas on Algonquin Transmission relating to the events of January 21, 2019.

Narragansett Electric has ten take stations at which it receives deliveries for firm customers from the Algonquin system.<sup>19</sup> Eight of the take stations are off the G-System – three take stations in the Providence area, and one each in Cumberland, Barrington, Warren, Tiverton, and Portsmouth.<sup>20</sup>

<sup>19</sup> “Firm customers” are defined as those whose service may not normally be interrupted and generally include most residential and commercial customers. In contrast, “interruptible customers” pay a lower price for gas service and are often interrupted during times of peak demand. These include power generators and other industrial customers who have dual fuel capability for heating or other uses.

<sup>20</sup> The other receipt points are in Westerly and Burrillville. There are other receipt points off the Algonquin system that serve generators in Rhode Island that are not related to gas distribution service provided by Narragansett Electric. Exhibit 1 to the Company’s Operational Balancing Agreement with Algonquin identifies all the Narragansett Electric receipt points. Attachment DIV 4-1, page 5. A listing of all the Narragansett Electric contracts can be found on the Algonquin website at: <https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG>

Aquidneck Island is located at the downstream end of the Algonquin G-System, leaving it in a vulnerable position with respect to unusual gas pressure conditions that might occur on the Algonquin system. All of Aquidneck Island depends exclusively on the G-System take station at Portsmouth for natural gas service. There are no other connections from Algonquin or any other interstate pipeline system to Aquidneck Island. The Portsmouth take station is at the “downstream” end of the G-System, with many customers located between it and the head of the G-System. As a result, a low-pressure condition on the G-System will have a particularly significant impact on the pressure of the Portsmouth take station. In addition, there is a single six-inch diameter pipe that delivers gas into the Portsmouth Station to serve all of Aquidneck Island, a smaller diameter connection to the mainline than many other locations on the Algonquin system.

### **1.2 Federal and State Regulatory Authority**

Under the federal Natural Gas Act, regulatory oversight over natural gas service is divided between federal and state authorities. PHMSA and FERC have authority over the interstate pipeline systems, including Algonquin. The Division has regulatory authority over regulated public utilities doing business in the state, but the Division has no regulatory authority over Algonquin or its parent company, Enbridge. While the Division has no regulatory authority over Algonquin, the Division coordinated with PHMSA in the investigation. PHMSA provided important information that allowed the Division to understand the sequence of events that resulted in the low-pressure condition on January 21, 2019. This complementary regulatory framework highlights the need for communication among Narragansett Electric, National Grid LNG and Algonquin to ensure reliability.

### **1.3 The Physical Attributes of Natural Gas Delivery**

The events of January 21, 2019 reflected important physical characteristics of natural gas transportation. Unlike the electric system, where the flow of electricity is nearly instantaneous across long distances, gas travels relatively slowly, typically between 10 and 30 miles per hour. As a result, gas pressure and flow anomalies that occur on gas delivery systems do not typically result in instantaneous effects across long distances.

Pressure on the interstate pipeline systems needs to be relatively high to move large volumes of gas. Once the gas reaches a take station, the gas pressure is reduced in order to flow

the gas into the distribution system as it is safely delivered to consumers. Gas service reliability is at risk if gas pressure drops below the level necessary to push the needed quantities to the gas load.<sup>21</sup> Gas pressure and gas flows, in this regard, are critical at every stage of the transportation process.

Along a pipeline, natural gas flows from high pressure supply areas to lower pressure demand areas. If there is a pipeline pushing natural gas in one direction and there are consumers taking gas all along the pipeline, gas will go to the demand that it first encounters. If there is not enough gas to meet the demand all the way to the end of the pipe, then consumers closest to the higher-pressure supply “upstream” will draw first. As less and less gas is available traveling downstream, the demand for gas will cause the system to try to pull more gas than is available. This, in turn, will cause the pressure on the overall system to drop. The only options to retain gas pressure in this scenario are either to inject more gas into the system (upstream or at the location of consumption) or to shut off demand. A low-pressure condition can create the risk of a widespread loss of gas service to customers on the gas distribution system.

Natural gas pipeline transmission companies design their systems to assure that there is enough gas supply, flow and pressure on the coldest days of the year to assure that all contracted levels of service to take stations can be served simultaneously, all the way to the most downstream take stations. This means that each take station on the interstate system is assigned an hourly maximum of natural gas that should not be exceeded during the hours of highest demand. However, it is not always possible to control the precise amount of gas draw. For that reason, pipelines may allow some flexibility for gas to exceed the hourly maximums to some degree, as long as the reliability of the system is not affected. But the degree to which this is allowed may vary from interstate pipeline to interstate pipeline. Nevertheless, if all take station locations in a subsystem are taking their maximum hourly flow and there is an unusual condition that causes one or more take stations on the system to draw amounts significantly over their maximums, this can cause the pressure on the pipeline to drop, if the aggregate draw exceeds the capacity of the system. Pressure and flow were factors in the events that transpired on January 21, 2019.

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<sup>21</sup> Here, gas load is the consumption by homes and businesses downstream of the take station.

#### **1.4 The Low-Pressure Distribution System on Aquidneck Island**

Aquidneck Island is vulnerable to low-pressure conditions that might occur on the Algonquin G-System based on its location at the end of the line. But there is another significant factor contributing to the outage that relates to the gas distribution system on Aquidneck Island itself. This system was acquired by Narragansett Electric in 2006 from Southern Union Gas Company, when Narragansett Electric purchased the gas distribution assets of Southern Union Gas Company and took over the gas distribution business. Responsibility for maintenance and planning of the gas distribution system on Aquidneck Island transferred to Narragansett Electric in 2006.

Because the detail of the system configuration may constitute confidential critical energy infrastructure information, the Report will not describe the configuration precisely. In general, the distribution system is not uniform but comprises a variety of pressures. This is not unusual in condensed areas within municipalities that had gas service installed long ago. Among these diverse systems on the island, there are bottlenecks along the pipes where the pipe size is not uniform from point to point. There is a lack of redundancy in some areas, with many areas of dead ends of distribution pipe. Sections also lack looping of service that would facilitate flow to stabilize pressures. This does not necessarily mean that the system is flawed, as these features are common to older systems that were initially constructed long ago.

### **Section 2.0 Operational Conditions in the Winter of 2018-2019**

The pipeline systems in and around Rhode Island experienced operational conditions during the winter of 2018-2019 that affected the events of January 21, 2019.

#### **2.1 The Role of Supplemental Liquefied Natural Gas (LNG)**

The supply of LNG is central to the events that occurred on January 21, 2019. This section will describe the use of LNG generally in the gas distribution industry, particularly in New England.

LNG is natural gas that has been liquified at very cold temperatures. When natural gas is liquified, its volume shrinks to 1/600<sup>th</sup> of its gaseous state. At this condensed volume, liquified natural gas can be stored in insulated tanks or transported by truck (as opposed to pipeline) to locations where it can be re-gasified (vaporized) and injected into a pipeline system (including

distribution company pipelines). While LNG serves many purposes in the domestic and global gas markets, one of its most important purposes in New England is to supplement natural gas pipeline supplies during winter peak periods.<sup>22</sup> Once vaporized into a system, LNG can maintain system pressures in distant areas of the gas distribution system during peak hours of demand on the coldest days of the year. In this manner, well-planned LNG storage and vaporization facilities can effectively counteract a low-pressure condition especially with respect to constrained areas of a gas system.

LNG is stored in large permanent tanks at various locations in New England. In some areas, there are vaporization facilities that can directly inject vaporized LNG into the interstate pipeline system. There also are vaporization facilities that inject directly into the local distribution system. LNG can be transported by trucks where it is taken to facilities to be vaporized and injected into points in the gas distribution system to maintain system pressures where there are no permanent storage facilities. Gas distribution companies can use temporary vaporization facilities that can be mobilized to areas of the distribution system when the gas distribution company identifies a risk of inadequate supply or system pressure based on forecasted conditions. These temporary facilities can be moved to locations near the gas distribution system at relatively short notice when the need arises due to unusual conditions.

Although the use of vaporized LNG to maintain system pressures is critical, injection of vaporized LNG generally occurs infrequently. During normal winters, it is possible in some situations where no injections would be necessary at certain locations for the entire winter. In many instances, the injection of vaporized LNG for system pressure support may occur for only a limited number of hours per year. The availability of LNG to address the small number of hours during the year when it is needed can be a very cost-effective alternative to adding interstate pipeline capacity, especially when the capacity risk and cost relate to a small number of days and hours during a given winter.

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<sup>22</sup> The use of LNG described in this Report to provide tactical support to the gas system is distinct from the large-scale international transportation of LNG from international supply areas that relies on LNG tanker ships and regasification facilities such as the one located at Everett, MA.

## **2.2 The Mothballed LNG Facility in Newport and Portable LNG Equipment**

Narragansett Electric has a lease and operating agreement with the Navy for an LNG facility at the Newport Naval Base. The lease was assumed when Narragansett Electric purchased the gas distribution business from Southern Union in 2006. The purpose of the facility was to ensure LNG availability for vaporization to meet design day peak hourly demand for the Navy's facility on Aquidneck Island. As explained in later sections of this Report, a design day is the coldest day that the gas utility forecasts could occur, based on certain forecasting criteria. Since design days are very rare, the facilities were rarely used. Nevertheless, the LNG facilities were available to assure system reliability.

In 2010, the Company purchased 6,000 dekatherms/day of incremental pipeline capacity from Algonquin to serve its Rhode Island loads. At that time, the Company informed the Commission and the Division that it did not need the LNG facility at the Newport Naval Base and mothballed the operations.<sup>23</sup> As a consequence, the LNG facility on the Naval Base was not operational in January of 2019.<sup>24</sup> Neither the Division nor the Commission approved the decommissioning. The decommissioning was simply reported by the Company in response to a question. The decision was within the discretion of the Company in the management of its operations and neither the Division nor the Commission at that time had any reason to question the decision.

The Company also owned temporary LNG equipment for potential use at the Portsmouth take station.<sup>25</sup> The Company had plans to use the temporary LNG equipment during the summer of 2019 when Algonquin was scheduled to perform maintenance on its interstate pipeline (which would eliminate gas to Portsmouth for the maintenance period). The equipment, however, was in storage for the winter of 2018-19 because the Company did not believe the equipment would be needed for the winter.

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<sup>23</sup> Response provided in 2010 to data request "Division 1-3(c) in PUC docket 4199.

<sup>24</sup> For a discussion of the status as of 2018, see Company testimony in PUC Docket 4872, beginning on page 34 of 50, which can be found at: [http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att\(10-22-18\).pdf](http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att(10-22-18).pdf)

<sup>25</sup> See pages 36 & 37 of 50 of the testimony in Docket 4872, cited above.

### 2.3 National Grid’s Providence LNG Facilities

In addition to the two other LNG facilities owned by Narragansett Electric in Rhode Island, there is a permanent LNG storage tank and associated vaporization facilities at Fields Point in Providence that is owned by Narragansett Electric’s affiliate – National Grid LNG, LLC. This facility enjoys a regulatory and commercial status that is not intuitively consistent with its operational function. The National Grid LNG facility in Providence engages in transactions of interstate commerce and is therefore subject to federal regulation and not a regulatory part of the gas distribution system over which the Division or the PUC has jurisdiction. However, the facility is directly connected to the gas distribution system of Narragansett Electric and operates as a key reliability resource for the distribution system. The facility does not have any direct physical connection to the interstate Algonquin system.<sup>26</sup>

Specifically, the facility vaporizes volumes of natural gas scheduled by its customers, including Narragansett Electric. When the facility is vaporizing gas into the Narragansett Electric gas distribution system in Providence, Narragansett Electric does not need to take as much natural gas from the Algonquin system at the Company’s Providence area take stations. Other customers purchase LNG from the facility through a “displacement” arrangement, whereby Narragansett Electric receives and uses the gas, and gas that otherwise would have been delivered to Narragansett Electric is then exchanged and taken by the customers at their locations in the interstate systems. In that sense, there is a “paper transaction” of a purchase and sale of gas. But, as a matter of actual gas flow, the LNG is injected into Narragansett Electric’s system. Thus, the vaporized LNG essentially displaces natural gas that otherwise would need to be drawn off the Algonquin G-System by Narragansett Electric.<sup>27</sup>

Despite its separate corporate identity, National Grid LNG’s internal structure also indicates that it is functionally a part of the Narragansett gas distribution system. The same group

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<sup>26</sup> A concise description of National Grid LNG, LLC and its facilities at Fields Point can be found in an order issued by the FERC in October of 2018, approving a liquefaction project for the facility. The order can be found at: <https://www.ferc.gov/media/statements-speeches/glick/2018/10-17-18-glick-CP16-121-000.pdf?csrt=4290037376884803216>

<sup>27</sup> Other customers purchase vaporized LNG from the facility through a “displacement” arrangement, whereby Narragansett Electric receives and uses the gas, and gas that otherwise would have been delivered to Narragansett Electric at other delivery points in the interstate systems is then exchanged and taken by the customer. In that sense, there is a “paper transaction” of a purchase and sale of gas. But the LNG is actually injected into Narragansett Electric’s system.

of employees are assigned to supervise and manage all LNG operations in Rhode Island together, including the LNG facilities owned by Narragansett Electric in other locations. In this way, the Providence LNG facility is essentially managed and operated as a part of the group of LNG assets within Rhode Island, together with the facilities owned by Narragansett Electric, which likely brings operational synergies for the National Grid companies and related benefits to their customers.<sup>28</sup>

On a day as cold as January 21, 2019, the Providence LNG facility was performing an important function. The facility was not only supplying gas to the wholesale customers of National Grid LNG LLC, but it also was reducing the amount of natural gas supply that otherwise would have been drawn from other sources by Narragansett Electric, including additional supply off the Algonquin system. In other words, to the extent vaporized LNG was being injected into the Narragansett Electric natural gas distribution system in Providence, the gas draw in the Providence area on this very cold day would be reduced from the Algonquin G-System. Conversely, to the extent vaporized LNG was not injected, more gas would need to be drawn off the Algonquin system.<sup>29</sup> The Providence LNG was particularly important to the gas distribution system from an operational perspective as it maintained pressure, flow and line pack of the gas distribution system to manage the cold weather event of January 21, 2019. So, when the Providence LNG vaporizers shut down unexpectedly in the early morning hours of that day, a greater draw of gas was required from the G-System during the most crucial early morning peak hours of January 21, 2019. The shut-off that occurred at the Providence LNG facility on the morning of January 21, 2019 was the third precipitating cause of the low-pressure condition.

#### **2.4 Cold Weather on January 21**

January 21, 2019 was one of the coldest days experienced over the last decade. According to data reported on “newportriweather.com,” the low temperature for Portsmouth on January 21 was 2 degrees Fahrenheit and the high was 12 degrees. According to the Company, there were only five days since January 2005 that were colder.

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<sup>28</sup> National Grid’s LNG group manages all operations of LNG facilities of National Grid across all National Grid operations in New York, Rhode Island, and Massachusetts.

<sup>29</sup> This is because the demand for gas in the Providence area did not change even as the source of supply to that demand did.



The temperature was not only cold on January 21, but the temperatures also changed rapidly over the course of the evening of January 20 into January 21.<sup>30</sup> For example, the weather report for T.F. Green Airport in Warwick shows that the temperature was above freezing in the early afternoon of January 20. By 5:00 pm on January 20, the temperature dropped to 25 degrees. By 9:51 pm, the temperature was only 18 degrees. Then by 1:51 am on January 21, the temperature had plummeted to 7 degrees. The temperature continued to drop to a low of 1 degree by 8:51 am.<sup>31</sup> Heavy rain was another weather factor. The rain hit the Warwick/Providence area on January 20 and was followed by the rapidly dropping temperatures in the early morning hours of January 21.<sup>32</sup>

### **Section 3.0 The Sequence of Events**

This section of the Report provides a narrative of the key events of January 21, 2019, leading up to the Company's decision to curtail gas service in the low-pressure system in Newport and a portion of Middletown.<sup>33</sup>

#### **3.1 Narrative of the Sequence of Events Up to Shut Off**

At 3:45 am on the extremely cold morning of January 21, operators on the Algonquin G-System identified a significant demand increase.<sup>34</sup> The amount of natural gas delivered to Rhode Island was the highest in Rhode Island history.<sup>35</sup> According to Algonquin, hourly takes on the Algonquin system were higher on January 21, 2019 than any day in the previous 10-year period.<sup>36</sup> The previous high peak hourly rate for the Algonquin system in January 2015 was equivalent to 2.9 billion cubic feet per day. On January 21, the peak hourly rate for the Algonquin system

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<sup>30</sup> Attachment DIV 1-26S.

<sup>31</sup> Attachment DIV 1-26S.

<sup>32</sup> Division 1-26 Supplemental and Attachment DIV 1-26S.

<sup>33</sup> Both the Division and PHMSA have produced timelines of events. If the timelines are compared, there are two important distinctions to note. First, the Division uses Eastern Standard Time, to match the actual times experienced in Rhode Island. In contrast, PHMSA and Algonquin use Central Standard Time, which is often used in the interstate pipeline industry. Second, the Division cites pressure readings at various locations that were obtained from Narragansett Electric's information. In contrast, PHMSA used readings in many instances from data retrieved from Algonquin data. The pressure readings do not always match precisely for the approximate hours identified but are not material.

<sup>34</sup> Algonquin Summary provided to PHMSA, dated Feb. 1, 2019 (hereinafter "Algonquin Summary to PHMSA").

<sup>35</sup> Attachment DIV 1-7S.

<sup>36</sup> "Chronological Explanation of the Events of January 21, 2019" from Enbridge (hereinafter "Enbridge Chronology for the Division").

reached approximately the equivalent to 3.3 billion cubic feet per day.<sup>37</sup> On the G-System, the total actual hourly takes significantly exceeded contractually scheduled nominations beginning at 4:30 am (EST) and continuing until 9:30 am (EST). Beginning at 5:00 am (EST), actual hourly takes at the ten delivery points on the G System into Rhode Island averaged more than 33% above maximum hourly limits based on the scheduled quantities for that day.<sup>38</sup>

During the hours between 3:45 am and 4:45 am, the gas distribution system of Narragansett Electric in Rhode Island was operating normally.<sup>39</sup> According to the Company, the G-System supplying the Company's take stations had inlet pressures ranging between 639 pounds per square inch gauge (psig) in Providence to 495 psig in Portsmouth.<sup>40</sup> However, according to Algonquin, the actual hourly takes at the Providence area meters where Narragansett Electric receives gas in the Providence area began to exceed Narragansett Electric's nominations that had been made for the gas day due to the high peak demand.<sup>41</sup> According to Algonquin, other unspecified customers of Algonquin on the G-System also were taking supply in excess of nominations.<sup>42</sup>

During this time prior to 4:45 am, the vaporization facilities at the Providence LNG facility were operating normally to provide supplemental supply into the Providence area.<sup>43</sup> At 4:44 am, the pressure at Portsmouth was in normal range, at 477 psi.<sup>44</sup>

At 4:45 am, the LNG facility experienced an unscheduled automatic shutdown.<sup>45</sup> According to information from PHMSA, the shutdown was initiated when the facility's uninterruptible power supply system failed, causing a loss of power. When power was lost, a "boil off" valve closed, which prevented the system from restarting.<sup>46</sup> According to Narragansett Electric, the area had experienced heavy rain on January 20 which left standing water in the area of the LNG plant that later froze when the temperature dropped during the late evening hours and

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<sup>37</sup> To calculate the equivalent daily rate, the hourly rate is multiplied by 24.

<sup>38</sup> Enbridge Chronology for the Division.

<sup>39</sup> Division 1-1.

<sup>40</sup> Division 1-1.

<sup>41</sup> Enbridge Chronology for the Division.

<sup>42</sup> Algonquin Response to PHMSA Item 38.

<sup>43</sup> NG LNG 2-1, page 2.

<sup>44</sup> Attachment DIV 4-4-1, page 58.

<sup>45</sup> Attachment NG LNG 2-1. National Grid control room described it as an "emergency shut down." Division 2-11

<sup>46</sup> Memo from National Grid to PHMSA, dated June 11, 2019.

early morning hours of January 21.<sup>47</sup> When the system could not restart, the fuel valves to three of the four vaporizers at the facility froze from ice buildup.<sup>48</sup>

There also were separate problems at the LNG facility with the burner management system and exhaust system. Vaporization records provided to the Division by the National Grid LNG affiliate show that the vaporizers began operating again briefly, but then shut down at 6:00 am and did not resume partial vaporization operations until sometime around 8:30 am.<sup>49</sup> Even after the facility resumed operations the unit continued to experience vaporization problems throughout the day.<sup>50</sup>

According to Algonquin and information provided to the Division by PHMSA, shortly after the Providence LNG facility experienced the first shutdown at 4:45 am, the hourly takes of natural gas at Narragansett Electric's take stations off the G-System increased dramatically.<sup>51</sup> According to Algonquin, actual hourly takes at the Providence area meters significantly exceeded scheduled nominations after 4:45 am. Algonquin's records indicate that the actual hourly takes at the combined ten delivery points serving Narragansett Electric reached as high as 54% *above* the maximum hourly limits for the hour beginning at 7:00 am.<sup>52</sup> Despite the increase in takes, neither Narragansett Electric nor National Grid LNG informed Algonquin of the shutdown of the facility when it occurred.<sup>53</sup>

As indicated, other Algonquin customers were already taking gas in excess of their scheduled nominations. Combined with the draw now occurring from the shutdown of the LNG facility, the demand on the Algonquin system was extreme.

According to information provided by PHMSA, within an hour after the Providence LNG facility experienced the shutdown, pressure at the head of the G-System began to drop.<sup>54</sup> While Algonquin was unaware of the LNG plant shutdown, it saw the significant increase in demand on the G-System. In response, around 7:20 am Algonquin initiated a remote system order to change

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<sup>47</sup> See Division 1-26 Supplemental and Attachment DIV 1-26S.

<sup>48</sup> NG LNG 2-1 and Memo from National Grid to PHMSA, dated June 11, 2019.

<sup>49</sup> NG LNG 2-1.

<sup>50</sup> See Attachment NG LNG 2-8-6, pp. 6-7.

<sup>51</sup> Algonquin Summary to PHMSA; Algonquin Response to PHMSA, Item JH 50, p. 2. (This response JH 50 contains confidential modeling information provided to PHMSA.)

<sup>52</sup> Enbridge Chronology for the Division.

<sup>53</sup> Algonquin Response to PHMSA, Item 45.

<sup>54</sup> Pressure data provided by PHMSA.

the gas flowing through its metering station in Weymouth.<sup>55</sup> This was done to increase the flow of gas from north to south on the mainline. However, the Remote Terminal Unit at the meter had been programmed incorrectly.<sup>56</sup> As a result, instead of the flow increasing, the meter controlling the flow began to cycle open and closed, restricting the flow of gas. According to PHMSA, flow should have increased from 550,000 dekatherms/day to 700,000 dekatherms/day. But instead, flow dropped to 150,000 dekatherms/day.<sup>57</sup> In turn, outlet pressure dropped from approximately 850 psi to approximately 450 psi.<sup>58</sup> As a result of the meter malfunction, the low-pressure condition on the “G-System” was exacerbated, instead of mitigated. According to Algonquin, when they were unable to resolve the issue remotely, a technician was sent to the meter location to address the issue, arriving shortly after 9:00 am.<sup>59</sup>

By 9:07am, Narragansett Electric began to experience a significant decrease in pressure at the Portsmouth take station. According to the Company’s records, pressure had dropped from 477 psi that was recorded around 4:45 am to 174 psi.<sup>60</sup> By 10:00 am, the inlet pressures from Algonquin to the Portsmouth take station had fallen to 97.7 psig.<sup>61</sup>

At around 9:45 am, a representative from Algonquin’s gas control called National Grid to report the valve malfunction. According to National Grid, the Algonquin representative apologized for the incident.<sup>62</sup>

By 9:55 am, National Grid began to direct its technicians and other personnel to Aquidneck Island to assist in the response to the emergency conditions.<sup>63</sup>

Shortly after receiving the call from Algonquin’s control center, at 10:18 am, the manager of the National Grid control center who had just spoken with the Algonquin representative sent an email to his boss, the Director of the control center, describing the low-pressure event as it was unfolding. In pertinent part, the email stated the following:

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<sup>55</sup> Enbridge Chronology for the Division.

<sup>56</sup> Algonquin Response to PHMSA, Item 2.

<sup>57</sup> Algonquin Response to PHMSA, Item 2.

<sup>58</sup> Psi information provided from PHMSA.

<sup>59</sup> Enbridge Summary for the Division.

<sup>60</sup> Attachment DIV 4-4-1, page 58.

<sup>61</sup> Division 1-1, page 2. At 97.7 psi, the inlet pressure was now 2.3 psi below the contractual minimum pressure specified in the capacity contract between Narragansett Electric and Algonquin.

<sup>62</sup> Division 1-1, page 2.

<sup>63</sup> Division 17-1.

The loss of the LNG had an immediate impact to our distribution system, the 200-psi line quickly dropped out to 100 psi, and the 99-psi system began to sag off as well. We picked up flow at Crary St and the loss of LNG naturally picked up the flow at Wampanoag Trail. This also had an immediate effect on the AGT G-System which supplies down to Portsmouth [sic] GS on Aquidneck Island. The inlet pressure to Portsmouth has collapsed from 459 psi at the time of the shutdown down to 90 psi. We have I&R standing by on the island top [sic] bypass reg stations if needed.

Coupled with the plant shutdown was an issue that AGT was having up in Massachusetts that contributed to the G-System suffering. They had a frozen valve on the Hub Line (Maritimes NE) supply in Weymouth Ma. They have since bypassed this valve and pressures have recovered nicely in the Weymouth – Milton area of MA but will likely take several hours to show any relief on Cape Cod and Rhode Island which are fed from the G-System.”<sup>64</sup>

Meanwhile, the Algonquin technician who had been dispatched to Weymouth by Algonquin around 9:00 am was able to obtain manual control of the valve at the Weymouth metering station and re-establish stable flow by 10:29 am in Weymouth.<sup>65</sup> But the low-pressure condition was already having a significant effect on Aquidneck Island.

According to the Company, the response team recognized the impact that the low pressure was having on the distribution system on the island at around 10:26 am. At that point, Narragansett Electric began a process to bypass gas regulators in Newport to increase the flow of gas into the low-pressure system.<sup>66</sup> By bypassing the regulators, the Company was attempting to compensate for the loss of pressure occurring across the gas distribution system. The Company then continued to manually open bypass valves at regulator stations at other locations on the island.<sup>67</sup>

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<sup>64</sup> Attachment DIV 4-4-1, page 39 and Division 2-2 Supplemental.

<sup>65</sup> Enbridge Chronology for the Division.

<sup>66</sup> Division 1-1, page 2.

<sup>67</sup> Division 1-1.

At 11:09 am, the Company began to receive phone calls from customers regarding lost gas service or poor pressure.<sup>68</sup> The Company's records show 11 calls received between 11:09 and noon. However, these figures were only from customers who called the Company. There is no data available to indicate how many customers were without gas service and simply had not called the Company about the issue. The Company's process was to have customer meter services technicians (CMS technicians) respond to the calls by visiting the premises to shut off the meters.<sup>69</sup> At this time, however, the Company had four CMS technician vehicles deployed on the island to respond to the incoming calls.<sup>70</sup>

By 11:30 am, the Company alerted its LNG Operations team of the situation. The Company did not have a process in place for the emergency deployment of LNG operations.<sup>71</sup> Nevertheless, the Company believed it might be able to mobilize portable LNG quickly enough to inject gas into the Aquidneck Island distribution system to increase supply and pressure.<sup>72</sup> The National Grid Director of LNG for Rhode Island then began to take steps to mobilize temporary portable LNG operations to the Portsmouth take station.<sup>73</sup> However, the various equipment and supplies necessary to mobilize the LNG vaporization operations were stored in different places. Portable containment equipment was in Cumberland and the portable LNG vaporizer equipment (owned by Narragansett Electric's Massachusetts affiliate) was in Leominster, Massachusetts. Arrangements also were needed to be made with contractors for site preparation and the transport of a required chemical (glycol) that was needed for operation of the facility.<sup>74</sup>

According to the Company, shortly after 8:35 am and continuing during the day, the Company and its affiliates also issued directives to increase LNG injections into the Algonquin system and local gas systems from other LNG facilities in Massachusetts and Rhode Island in an effort to reduce demand on the Algonquin G-System.<sup>75</sup> The Company also took steps to increase

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<sup>68</sup> Attachment DIV 1-14. (This file includes confidential customer information which is not public.)

<sup>69</sup> Division 17-5.

<sup>70</sup> Division 17-12. The Company has no count of when actual technicians arrived on the island to respond to calls. Instead, the Company has used information available to determine how many CMS vehicles were deployed. See Attachment DIV 17-12-1, page 1 of 1. For that reason, the Division uses the vehicle count in the description of the sequence of events.

<sup>71</sup> Division 12-12. According to the Company, temporary LNG operations always were deployed based on a specified need well in advance of deployment and typically is installed over a 72-hour period.

<sup>72</sup> Division 12-13.

<sup>73</sup> Division 12-14.

<sup>74</sup> Division 6-3.

<sup>75</sup> Division 1-1.

natural gas flow into Rhode Island from the Tennessee Gas pipeline into Rhode Island, for the same purpose.<sup>76</sup>

According to Algonquin, at around 11:55 am, the Weymouth station was restored to normal operations.<sup>77</sup> By 12:06 pm, the Company made an operational decision to shut off service to a portion of the low-pressure system serving a small area of Middletown, curtailing service to over 360 customers.<sup>78</sup> According to the Company, by isolating the smaller district the Company hoped to maintain pressures to the higher-pressure system supplying gas to the larger integrated low-pressure district in Newport.<sup>79</sup> The Company did not make any attempt to sectionalize other areas of the low-pressure system in Newport. According to the Company, it was not possible as a practical matter because the low-pressure system was not designed for sectionalizing and did not have shut-off valves designed for sectionalizing districts.<sup>80</sup> By 12:15 pm, the Company had deployed ten CMS technician vehicles to Aquidneck Island to respond to customer calls.<sup>81</sup> By 12:22 pm, the inlet pressure at the Portsmouth take station fell to 36.4 psig, the lowest recorded pressure. As a result, the impact on the low-pressure system in Newport spread.<sup>82</sup>

At 12:00 pm, the manager of the portable LNG projects had received word from the Company's glycol transporter that the contractor would not be able to deliver any glycol to Portsmouth for operation of the vaporizer equipment because there were no vehicles prepared or available for transport.<sup>83</sup> As a result, the manager began reaching out to other glycol suppliers. Also, according to the Company, the contractor that the Company used for transporting vaporizer equipment did not have personnel immediately available to transport the vaporizer equipment because of the holiday.<sup>84</sup>

By 1:00 pm, the Company had now received over 150 phone calls from customers without gas service or poor pressure.<sup>85</sup> Field technicians were being dispatched in a centralized manner to

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<sup>76</sup> Division 6-4.

<sup>77</sup> Enbridge Chronology for the Division.

<sup>78</sup> Division 1-1, page 3.

<sup>79</sup> Division 1-1, page, 3.

<sup>80</sup> Division 18-9.

<sup>81</sup> Attachment DIV 17-12-1.

<sup>82</sup> Division 1-1, page 3.

<sup>83</sup> Division 12-14.

<sup>84</sup> Division 12-26.

<sup>85</sup> Attachment DIV 1-14.

visit locations that had reported gas outages, attempting to shut off the services at those locations.<sup>86</sup> As of 1:23 pm, there were 20 CMS technician vehicles deployed on the island.<sup>87</sup>

At 1:45 pm, matting needed to support the LNG vaporizing equipment at the Portsmouth take station arrived and crews began to install it on site.<sup>88</sup>

By 2:00 pm, the number of “no gas/low pressure” calls rose to 370 customers.<sup>89</sup> The Company now had twenty-seven CMS technician vehicles deployed on the island.<sup>90</sup> By approximately 2:30 pm (as estimated by the Company), the command team made a decision to decentralize the process of dispatching field technicians to customers without gas service and changed to a local dispatch operation.<sup>91</sup> In addition, at some unspecified point during the event, the Company began implementing procedures to identify the scope of the problem. While the command team was aware of no gas calls that were being received, the Company did not have real-time data linked to its system maps. Given the circumstances where all the specific outage locations were not known, the Company implemented a process to manually “inventory” the extent of the outages.<sup>92</sup> This outage inventory was literally a manual process requiring technicians to survey the area on foot, checking from regulator stations outward to the end points of the low-pressure system. This process did not identify all the outages, but the Company maintains that it gave the command team a sense that the effects were growing more widespread on the low-pressure system.<sup>93</sup>

While there also were sporadic outages in parts of the higher-pressure systems on Aquidneck Island, they were limited in number.<sup>94</sup> Given the situation, the Company was able to maintain adequate pressures in those distribution segments, due in part to the actions it was taking to bypass regulator stations that kept the flow of gas at manageable pressures in those segments.<sup>95</sup>

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<sup>86</sup> Division 18-8.

<sup>87</sup> Attachment DIV 17-12-1.

<sup>88</sup> Division 12-14.

<sup>89</sup> Attachment DIV 1-14.

<sup>90</sup> Attachment 17-12-1.

<sup>91</sup> Division 18-8.

<sup>92</sup> Interviews, July 18, 2019.

<sup>93</sup> Interviews, July 18, 2019.

<sup>94</sup> Outage map, Attachment DIV 1-4-2 (This map contains Confidential Energy Infrastructure Information and is not public.)

<sup>95</sup> Division 1-1.



By 3:00 pm, the total of “no gas/low pressure calls” rose 650. By 4:00 pm, the calls reached 965<sup>96</sup> and the number of CMS vehicles deployed to respond to the calls was increased to twenty-nine.<sup>97</sup>

At 4:00 pm, the portable containment equipment for the LNG vaporization operation arrived in Portsmouth.<sup>98</sup> But the rest of the equipment (including the vaporizers) had not yet arrived and the site was still not ready for operation.

By this time, pressures off the “G System” at the Portsmouth take station began to increase toward normal pressures.<sup>99</sup> But the conditions on the low-pressure distribution system remained unstable and presented a safety risk.<sup>100</sup>

At 4:05 pm, the Company’s Gas Dispatch department provided the emergency response team with the actual list of “no gas” calls that had been received up to that point, which the engineers began to map around 4:30 pm.<sup>101</sup> According to the Company:

The Company expected that areas of no gas calls would occur on the southern peripheries or end points and crews could isolate those segments and maintain supply to the core integrated district. At 4:30 p.m., Dispatch provided a list of no gas calls. Engineering then prepared a map of the outages. National Grid then overlaid that outage map on the entire integrated low-pressure system and immediately recognized that the outages spread across all segments, including the northern and central segments.<sup>102</sup>

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<sup>96</sup> Attachment DIV 1-14.

<sup>97</sup> Attachment DIV 17-12-1.

<sup>98</sup> Division 12-14.

<sup>99</sup> Attachment DIV 4-4-1, page 58.

<sup>100</sup> Division 1-1, pages 4-5.

<sup>101</sup> Division 1-1, page 4. The Company maintains that Gas Dispatch was “in frequent communication” with the leadership team during the course of the day, but there is no indication that detailed data was made available until 4:00 pm. See Division 17-7.

<sup>102</sup> Division 1-1, page 4.

Around 5:15 pm, the Company learned that it would not be able to receive delivery of sand and spill containment supplies necessary for the LNG operations until later that evening.<sup>103</sup>

By 5:00 pm, the Company had deployed forty-two CMS technician vehicles to the island. The “no gas/low pressure” call count was 1,250, rising to 1,325 by 6:30 pm.<sup>104</sup> By this time, the inlet pressure at the Portsmouth take station had increased to 257 psig.<sup>105</sup> But the outages that had already occurred on the low-pressure system were widespread.

At 6:50 pm, the Company made the decision to shut down the entire low-pressure system in Newport to protect the health and safety of the customers and communities.<sup>106</sup> According to the Company, if gas flow was restored, it would create safety risks for any home and business who happened to be using pilot-driven gas equipment and the Company had no way of knowing how many homes and businesses within the low-pressure system used such equipment in these historic communities.<sup>107</sup> A sudden return of flow of gas into pilot-driven appliances that had lost gas and the pilot-light was extinguished could create significant safety risks for customers because gas would flow past unit pilot-lights and be subject to ignition. Shutting down service to the over 7,000 gas customers on the low-pressure system assured that the sudden return of gas pressure to homes and businesses that had experienced outages would not inadvertently create those safety risks that could result in personal injury or property damage.

At 7:00 pm, the contractor completed the installation of matting at the Portsmouth vaporization site, but the shutdown of the low-pressure system in Newport was already underway.<sup>108</sup> At 8:28 pm, the last regulator station serving the low-pressure system was shut off, completing the shutdown.<sup>109</sup>

At 8:30 pm, the first vaporizer arrived in Portsmouth from Leominster, Massachusetts, but since the low-pressure system was already curtailed, there was no reason to begin injecting vaporized LNG into the system.<sup>110</sup>

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<sup>103</sup> Division 12-14.

<sup>104</sup> Attachment DIV 1-14 and Attachment DIV 17-12-1.

<sup>105</sup> Attachment DIV 4-4-1, page 59.

<sup>106</sup> Division 1-1, page 4.

<sup>107</sup> Division 1-1, page 5.

<sup>108</sup> Division 12-14.

<sup>109</sup> Division 1-1, page 5.

<sup>110</sup> Division 12-14.

While the Company had been in continuous communication with the Division throughout the day, the Company never notified the Division that there had been a shut-down of the LNG facility in Providence that some employees believed had an impact on system pressures.

### **3.2 Timeline Related to the Sequence of Events**

Below is an abbreviated timeline of the events from 3:45 am to 8:30 pm.

**Table 1 – Timeline of Events on January 21**

3:45 am – High Demand on Algonquin System, Portsmouth inlet psig at 495.
4:30 am – Providence LNG facility vaporizers operating normally; Portsmouth psig at 477.
4:45 am – Automatic shutdown occurs at Providence LNG facility; hourly takes off G System begin to increase.
7:00 am – Hourly takes at Narragansett Electric points on Algonquin are 54% above limits.
7:20 am – Enbridge initiates a remote system order to change flow on Algonquin system from north to south at Weymouth metering station. Instead of increasing flow, the meter controlling the flow begins cycling, restricting the flow of gas.
8:30 am – Providence LNG facility resumes vaporization, but still experiencing problems.
8:35 am – National Grid control room begins issuing directives for the Company and its Affiliates to inject LNG into the Algonquin system to reduce demand on the Algonquin system.
9:00 am – Enbridge unable to resolve issue remotely, sends technician to Weymouth station.
9:07 am – Significant decrease in pressure at Portsmouth: now at 177 psig (compared to 477).
9:45 am – Algonquin representative calls National Grid to report valve failure.

9:55 am – National Grid issues directive for technicians and personnel to report to Aquidneck Island.

10:00 am – Inlet pressure at Portsmouth falls to 97.7 psig.

10:18 am – National Grid control center manager sends email to upper management reporting on Providence LNG shutdown and Algonquin valve failure.

10:26 am – Due to pressure problems experienced on distribution system, National Grid begins bypassing regulator stations to increase flow to low-pressure systems.

10:29 am – Algonquin technician obtains manual control of valve in Weymouth to re-establish flows.

11:09 am – National Grid begins receiving calls from customer reporting no gas or low pressure (11 calls received between 11:09 and noon).

11:30 am – National Grid alerts its LNG operations team to mobilize portable LNG to Aquidneck Island.

11:55 am – Algonquin metering station in Weymouth restored to normal operations.

12:00 pm – National Grid’s manager of LNG portable projects receives word that the Company’s glycol transporter cannot deliver glycol as requested for operation of portable LNG facilities in Portsmouth.

12:06 pm – National Grid shuts off service to portion of low-pressure system in Middletown, curtailing service to over 360 customers to maintain higher pressures on the high-pressure systems.

12:22 pm – Inlet pressure at Portsmouth take station falls to lowest level of 36.4 psig.

1:00 pm – No gas/low pressure calls from customers has now risen to over 150 calls.

1:45 pm – Matting arrives in Portsmouth to support potential LNG operations.

2:00 pm – No gas/low pressure calls have risen to 370.

3:00 pm – No gas/low pressure calls have risen to 650.

4:00 pm – Portable containment equipment for LNG vaporization arrives in Portsmouth.  
No gas/low pressure calls have risen to 650. Pressures into Portsmouth take station returning to normal, but customers on the low-pressure portion of distribution system in Newport have already experienced a high number of outages.

4:05 pm – List of no gas/low pressure calls is provided by Gas Dispatch to command team.

4:30 pm – Engineers begin mapping the location of gas outages from calls. Mapping results eventually show widespread outages across Newport.

5:00 pm – No gas/low pressure calls at 1,250.

6:30 pm – No gas/low pressure calls at 1,325.

6:50 pm – National Grid makes decision to curtail service to entire low-pressure system in Newport for safety reasons.

8:28 pm – The last regulator station serving the low-pressure system is shut down.

8:30 pm – First portable LNG vaporizer arrives in Portsmouth. But system is already curtailed.

#### **Section 4.0 The Precipitating Events**

This section of the Report details the precipitating events that caused the low-pressure condition. The next section of the Report will then address the Company’s pre-event planning processes and ultimate response to the low-pressure condition.

As reflected in the sequence of events, it was a low-pressure condition on the Algonquin “G System” that ultimately led to the gas service outage. In the course of its investigation, the Division, in coordination with PHMSA, sought to identify the factors that contributed to this low-pressure condition. The investigation reviewed the data and ultimately concluded that there were three significant contributing factors to the low-pressure condition, all three of which were necessary in order for the low-pressure condition to occur. Those three factors were:

- (1) An unusually high demand on the “G System” from the extremely cold conditions that placed a strain on the system, driven in part by Algonquin customers on the “G System” drawing gas in excess of their previously specified nominations for that day.<sup>111</sup>
- (2) The shutdown of the Providence LNG facilities that caused even higher overtakes on the G-System; and
- (3) The malfunction of the Algonquin metering valve at the Weymouth metering station which had been programmed incorrectly by Enbridge during the fall of 2018.

Described chronologically, the high demand on the G-System during the morning of January 21 was already placing significant stress on the Algonquin system. With the high demand, the unexpected shutdown of the Providence LNG vaporization facilities created further instability on the Algonquin G-System.<sup>112</sup> More natural gas was drawn into the Providence area from the Algonquin system to replace the volumes that otherwise would have been met on that cold morning by the LNG facility, causing hourly takes off the G-System that far exceeded the nominations made by National Grid into the Providence area.<sup>113</sup>

In a memo provided to PHMSA from the National Grid affiliate operating the facility, the affiliate explained the cause of the plant shutdown:

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<sup>111</sup> Enbridge did not identify the other customers who were drawing gas in excess of nominations. The Division notes from the public records published by Algonquin, however, that other utilities such as National Grid in Massachusetts, Eversource, and (to a lesser extent) New England Gas Company, typically schedule large quantities of gas on the coldest days.

<sup>112</sup> National Grid LNG Memo to PHMSA 6/11/19

<sup>113</sup> Algonquin response to PHMSA, Item JH 50 and other information provided by PHMSA (This response contains confidential modeling information).

National Grid LNG, LLC (“NGLNG”) has analyzed the issues experienced at the Providence LNG plant on January 21, 2019. NGLNG has determined that an automatic plant shutdown occurred because of an interruption in power supply on the automatic plant shutdown system. When that automatic plant shutdown occurred, the boil-off valve closed. The plant was unable to restart immediately because the relay on the boiloff value failed to reset. The weather conditions, which included rapidly dropping temperatures and freezing rain, caused the boil-off valve and the fuel valves to the vaporizers to quickly freeze closed. The plant operators were able to manually open the boil-off valve and thaw the fuel valves and restart the plant (the fuel valves continued in automatic as the compressor valve was still manual). Additionally, after the plant restarted vaporizing, operators identified problems with the burner management system on vaporizer 3 and the damper on vaporizer 2 that reduced the plant output.

According to PHMSA, National Grid LNG experienced an emergency shutdown in November 2018 due to a failed uninterruptible power supply which it did not adequately investigate or resolve.<sup>114</sup>

Based on the results of modeling performed by Enbridge which PHMSA provided to the Division, it does not appear that the shutdown of the LNG facility, by itself, could have caused enough instability to precipitate in the outage on Aquidneck Island, even when combined with the large draw in excess of nominations from other Algonquin customers on the G-System.<sup>115</sup> But the sequence did not end there.

As the gas flows off Algonquin increased dramatically, the pressures on the G-System were materially affected downstream. While Algonquin was not immediately aware of what occurred at the Providence LNG facility, the Enbridge control center identified the instability and took steps to mitigate the system problem by sending a signal to its Weymouth metering station to increase the flow of gas from north to south. But the valve malfunctioned and instead of increasing the

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<sup>114</sup> PHMSA Accident Investigation Report, August 13, 2019. Page 11 and 24.

<sup>115</sup> Algonquin response to PHMSA, Item JH 50 (This response contains confidential modeling information).

flow, the gas flow decreased, exacerbating and extending the time of the low-pressure condition. The metering valve malfunction was caused by a programming error that had been made in September of 2018.<sup>116</sup> Enbridge described the error in technical terms:

An incorrect meter factor . . . which converts pulses from the meter to a volumetric flow rate, was stored within the Remote Terminal Unit. The incorrect meter factor caused the system to significantly inflate the calculation of natural gas flow through the meter facility, causing two control valves to continue cycling until [the pressure regulator] was set to manual by the Technician.<sup>117</sup>

Had the meter factor been set correctly in September of 2018, the valve would have increased the flow of gas into the Algonquin system, instead of restricting the flow and exacerbating the problem.

The Division coordinated with PHMSA to request that Enbridge conduct a series of modeling exercises based on several counter-factual scenarios.<sup>118</sup> After receiving the modeled results, the Division compared the modeled inlet pressures under each scenario at the Portsmouth take station to the lowest inlet pressure modeled by National Grid at which the low-pressure system likely would have been sustained. In each of the scenarios, the inlet pressure at Portsmouth exceeded the pressure needed to sustain the distribution system.<sup>119</sup> Based on these modeled results, it appears that if the Algonquin valve in Weymouth had operated properly, it would have been enough to provide sufficient supplemental gas flow to mitigate the unstable condition on the G-

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<sup>116</sup> According to PHMSA, Enbridge's programming logs indicate that the mechanism controlling the flow rate was adjusted in September of 2018. This appears to be the time the programming error was made.

<sup>117</sup> Algonquin Response to PHMSA Item 2.

<sup>118</sup> Algonquin response to PHMSA, Item JH 50. This response to PHMSA contains confidential modeling information. For that reason, the resulting modeled inlet pressures for each scenario have been redacted in the copy provided in the Appendix to this Report, consistent with the confidentiality designation that was included on the response when it was provided to PHMSA under the federal process.

<sup>119</sup> See Division 21-5 for a description of National Grid's modeled results. It is important to point out that the modeled pressures also exceeded the contractual minimum pressure for Portsmouth.



System caused by gas flows in excess of nominations, thus avoiding the curtailment that eventually occurred on the island.<sup>120</sup>

The Division did not independently validate the complex modeling analyses conducted by Enbridge.<sup>121</sup> However, the underlying assumptions for each scenario were identical and the information was provided by Enbridge to PHMSA as a part of a formal investigation. The scenario modeling performed by Enbridge of the Algonquin system indicates that no single event among the three, or any combination of two events by themselves, would have created a sufficient low-pressure condition in Portsmouth to force to the outage. Instead, the modeling indicates that the occurrence of all three factors was necessary – high demand, a malfunctioned valve, and a malfunctioned LNG facility – to create the low-pressure condition which forced Narragansett Electric to shut down the gas distribution system on Aquidneck Island.

While the Division references modeling performed by Enbridge, it is important to point out that Enbridge had complete control over the modeling and inputs. While the Division has no reason to question the modeling process, the assumptions used, and the results obtained, it is equally important to point out that substantive review of the Enbridge modeling was not within the Division’s authority. For example, the Division also learned through PHMSA that there were other factors present on the Algonquin system. According to PHMSA, these appear to have been less likely to have materially contributed, but they were present nevertheless. Specifically, the Algonquin mainline (west of the G-System) experienced compressor problems which could have contributed to the instability that morning.<sup>122</sup> Finally, there is a question whether the “line pack” within the Algonquin system was less than optimal that morning.<sup>123</sup>

It is not the Division’s role to assess degrees or percentages of responsibility from the convergence of events. This is something that may only be sorted out in future legal proceedings involving the various possible contributors to the event, as liability among the parties is disputed

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<sup>120</sup> Further, a newspaper report quotes an Enbridge spokesperson stating: “This equipment malfunction and temporary supply restriction may have been a contributing factor to the low-pressure situation in combination with the high demand for gas and the unexpected loss of natural gas supply from the National Grid LNG facility.” See <https://www.newportri.com/news/20190301/enbridge-points-to-national-grid-other-sources-for-newport-gas-outage>

<sup>121</sup> Even if the Division had access to the data, the Division estimates that the cost of hiring a qualified firm to reproduce the modeling could have ranged between \$250,000 and \$500,000.

<sup>122</sup> The information from PHMSA reflecting the details of the compressor problems were confidential.

<sup>123</sup> “Line pack” refers to gas intentionally built up in the pipeline system by the pipeline company prior to peak demand hours that can help compensate for fluctuations in gas demand during a given gas day.

in the courts. Rather, it is the Division’s role to assess the planning, actions, and responses of Narragansett Electric that occurred before, during, and after the outage event on Aquidneck Island.

Additional analysis of the precipitating factors and modeling of their impacts may be found in the Investigation Report issued by PHMSA.

### **Section 5.0: Preconditions Contributing to the Outage**

In addition to the precipitating factors that caused the low-pressure condition, there were a number of preconditions that resulted from the way that Narragansett Electric had managed the gas distribution system over the previous decade that made it significantly more difficult for the distribution system to sustain minimum necessary pressure in the event of a low-pressure event. This section details the two major preconditions: first, a lack of LNG vaporization on Aquidneck Island and second, a lack of contingency planning.

#### **Section 5.1: Lack of LNG Vaporization Facilities on Aquidneck Island**

As described earlier in this Report, Narragansett Electric has a lease and operating agreement with the Navy for an LNG facility at the Newport Naval Base on Aquidneck Island. The Company also had temporary equipment on hold for potential use at the Portsmouth take station on the Island when Algonquin was scheduled to perform system maintenance during the summer of 2019. However, the Company had mothballed the pre-existing LNG facility in Newport and did not foresee any need to have any temporary LNG facilities at the Portsmouth take station in place as a contingency on January 21.

If LNG vaporization facilities had been operational on Aquidneck Island when the low-pressure condition on the Algonquin system began to cause instability on the gas distribution system on the island, the injection of vaporized LNG into the gas distribution system likely would have avoided the need to curtail service in Newport on January 21, 2019. During interviews, no one at the Company disputed the reasonableness of this belief when the Division raised it.<sup>124</sup> However, based on its “design day” forecasting the Company relied upon for projecting need, the Company had made an operational judgment that LNG injections would not be needed for the

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<sup>122</sup> See the testimony in Docket 4872, page 35 of 50. Found at: [http://www.ripuc.org/eventsactions/docket/4872-ngrid-jointrebuttal-w-att\(10-22-18\).pdf](http://www.ripuc.org/eventsactions/docket/4872-ngrid-jointrebuttal-w-att(10-22-18).pdf)

winter of 2018-19.<sup>125</sup> While January 21 was not a design day, the Division believes accurate design day planning would have called for LNG facilities to be in place for the entire winter.

### 5.1.1 Design Day Forecasting

When determining whether LNG vaporization capacity or other actions or infrastructure investments are needed to assure reliable gas service, gas utilities apply criteria referred to in the gas industry as design day planning. Design day planning is based on a measure referred to in the energy industry as heating degree days (“HDD”). Specifically, generally accepted industry standards call for a forecasting analysis to assure that there is enough capacity and supply available to serve customers on the worst (or coldest) day that might realistically occur. It is based on a forecast of need tied to a “heating degree day” temperature. A “heating degree day” is the average of the lowest temperature plus highest temperature divided by 2, subtracted from 65 degrees.<sup>126</sup> 65 degrees is used as the baseline for measuring HDD under industry standards because it is the temperature when no heating or cooling is typically needed.

For Narragansett Electric in Rhode Island, the Company uses a design day HDD of 68 degrees.<sup>127</sup> In other words, if the utility follows industry criteria, it must plan its system and procurements to assure that on a day that reaches 68 HDD, there will be no gas service outages (assuming the system is functioning properly without incidents beyond the control of the utility). Translated into ordinary nomenclature, a 68 HDD is equal to an average temperature of -3 degrees Fahrenheit (i.e.,  $65 - 68 = -3$ ). Under the Company’s analysis, a 68 HDD would likely occur approximately once in 59 years.<sup>128</sup>

In the context of Aquidneck Island, the Company concluded that its design day criteria had been met without the need for supplemental LNG on Aquidneck Island.<sup>129</sup> This turned out to be an erroneous conclusion. In fact, the Company has since reconsidered how it was evaluating the need at Aquidneck Island and now acknowledges that there is a need for vaporized LNG on the island. While January 21 was not a “design day” (i.e., only 59 HDD), appropriate design day

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<sup>125</sup> See the testimony in Docket 4872, page 35 of 50. Found at: [http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att\(10-22-18\).pdf](http://www.ripuc.org/eventsactions/docket/4872-NGrid-JointRebuttal-w-att(10-22-18).pdf)

<sup>126</sup> For example, a day with a low of 5 degrees and a high of 16 degrees would be a 44 HDD:  $65 - (5 + 16)/2 = 44$ .

<sup>127</sup> See National Grid’s amended “Gas Long-Range Forecast and Requirements Plan for the Forecast period 2019/20 to 2023/24,” (“LRP”) page 13, filed in Docket 4816. Found at: [http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20\(7-2-19\).pdf](http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf)

<sup>128</sup> See the “LRP”, page 13, cited in footnote above.

<sup>129</sup> See Division 12-16.

planning which appropriately considered hourly peak flows into the Portsmouth take station would have indicated the need for LNG on the island. This error was the result of a complex set of assumptions in planning, as described below.

### **5.1.2 Reliance Upon the Operational Balancing Agreement with Algonquin**

Narragansett Electric has ten take stations on the Algonquin system for service into Rhode Island.<sup>130</sup> Each of the take stations have both a daily flow and an hourly flow contract limit. If either the daily or the hourly limits are exceeded, the Algonquin customers using the system (in this case Narragansett Electric) could be subject to financial penalties from the interstate pipeline (in this case Algonquin). However, it is well understood in the industry that it is not possible to deliver and take the precise quantities that are scheduled over the course of a “gas day.” For that reason, customers on the interstate system each have an “Operational Balancing Agreement” (OBA) with the pipeline. For those interconnected customers with more than one take station from the same pipeline, under the OBA, at the end of the gas day all deliveries to each take station are aggregated and the interstate pipeline will typically accept the total in the aggregate, as long as it does not exceed the aggregated limits and the reliability of the system was not affected by any excess takes at any given take station.<sup>131</sup>

According to Narragansett Electric, it has been relying on its OBA for many years, where Algonquin has allowed the Company to aggregate all of its take stations for purposes of measuring both hourly and daily quantities.<sup>132</sup> Thus, to the extent the hourly or daily maximum was exceeded at the Portsmouth take station serving Aquidneck Island, Algonquin would accept the end result and not penalize the Company.<sup>133</sup> According to the Company, this has been occurring historically without any reliability issues or penalties. Because of this practice, National Grid has been doing its design day planning on a “portfolio-wide” basis for all of Rhode Island, believing it was not necessary to consider whether its maximum takes at any given location among the ten take stations might be exceeded.<sup>134</sup> The Company’s supply planning group did not consider the forecast of

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<sup>130</sup> See Exhibit 1 to the Company’s Operational Balancing Agreement with Algonquin, identifying the receipt points. Attachment DIV 4-1, page 5.

<sup>131</sup> Division 3-9. A copy of the OBA is attached to Division 4-1.

<sup>132</sup> Division 3-9.

<sup>133</sup> Division 3-9.

<sup>134</sup> See Division 3-4. See also the explanation provided by the Company to the Division in the Letter from National Grid to K. Lynch 1/25/19, provided in Appendix A.

deliveries that might come to the Portsmouth take station (in isolation) on a design day. The Company essentially considered its Algonquin delivery rights as a whole and balanced the aggregate of all its takes on any day and any hour across all take stations on the Algonquin system, including the Portsmouth take station.<sup>135</sup> The Company described its practice as follows:

[T]he Company has understood, both through the OBA and through operational practices consistent for years, that exceeding maximum daily or hourly quantities at individual take stations off the Algonquin system would not and did not imperil reliable service on Aquidneck Island or anywhere else, so long as demand across the Company's take stations receiving gas from Algonquin did not exceed the total combined [maximum daily quantities] and the allowed imbalance tolerance on the day.<sup>136</sup>

The forecasting process used by the Company to determine capacity needs on the interstate pipeline system rested on this assumption. Specifically, the forecasting department would forecast daily quantities and hourly demands throughout its system for design day evaluation. In performing this function, the department would provide the annual forecast of daily and hourly demands at each take station to engineering in order to allow for an evaluation of the local distribution system needs. However, the forecasting department would not provide the hourly forecast by take station to the Energy Procurement business unit that was responsible for evaluating interstate pipeline capacity needs.<sup>137</sup> As a result, the Energy Procurement business unit responsible for assuring adequate interstate pipeline capacity did not evaluate hourly peak needs at individual take stations for purposes of design day capacity and supply planning. This planning assumption and evaluation process, the Division believes, was a key factor leading to the Company's decision not to recommission the LNG facilities at the Naval Base or install the temporary LNG vaporization facilities at the Portsmouth take station for the winter of 2018-19.

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<sup>135</sup> Interview, July 10, 2019.

<sup>136</sup> Division 3-9, page 2.

<sup>137</sup> Interview, July 10, 2019.

### 5.1.3 Forecasting Error and Subsequent Acknowledgement of Need for LNG

As will be explained below, in a separate proceeding and investigation in a Public Utilities Commission docket that arose in 2018, the Division inquired about hourly peak capacity limits into Aquidneck Island. In response, the Company performed an analysis of hourly peak demand for the Division, concluding that the hourly forecast did not indicate a need for new incremental pipeline capacity into Aquidneck Island until the winter of 2022-23.<sup>138</sup> In March of 2019, however, the Company disclosed that it had made a forecasting error relating to the contractual capacity limits into Aquidneck Island.<sup>139</sup>

Months before the events of January 21, 2019, the Division and the Commission were reviewing a proposal by National Grid to pay a \$7.2 million energy efficiency incentive to the Navy for the installation of an 8 MW gas-fired combined heat and power (CHP) generation project at the Navy base in Newport (CHP docket).<sup>140</sup> During those proceedings, the Division questioned the Company's ability to supply such a large gas-fired project, which would create a substantial demand on the gas system on Aquidneck Island.

One area of inquiry related to the Company's forecasts. Specifically, the Division asked the Company in November of 2018 when the Company believed it would face a constraint on the island for adding new firm gas customers, including a request for peak hourly demand analysis.<sup>141</sup> The Company maintained that there would be no problem serving new gas customer load until the winter of 2022-23. The response included a forecast, indicating that the hourly limit at the Portsmouth take station was 1,122 DK/hr, but such limit would not be reached until the winter of 2022-23.<sup>142</sup> No mention was made in this response about the relevancy of the Company's Operational Balancing Agreement.

After the January 21 outage, the Division sent an official communication to Narragansett Electric indicating concern that the Company did not have LNG facilities on Aquidneck Island.<sup>143</sup> On January 25, 2019, the Company responded in a letter.<sup>144</sup> The letter maintained that there was

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<sup>138</sup> Docket 4755, Company's original response to Division 10-25. The Division asked the question on November 27, 2018. The Division did not receive a response to its question until January 25<sup>th</sup> – four days after the outage in Newport.

<sup>139</sup> Docket 4755, Division 10-25 Corrected and Supplemental.

<sup>140</sup> See PUC Docket 4755. The Company later withdrew its proposal.

<sup>141</sup> Docket 4755, Division 10-25.

<sup>142</sup> Docket 4755, Division 10-25.

<sup>143</sup> See Letter from K. Lynch to National Grid 1/24/19, provided in Appendix A.

<sup>144</sup> See Letter from National Grid to K. Lynch 1/25/19, provided in Appendix A.

sufficient pipeline capacity in the Company's portfolio to meet requirements on Aquidneck Island. The letter also contained the following statement:

As explained during the recent Gas Recovery proceeding before the Public Utilities Commission in Docket 4872, the Company did not expect to need LNG operations on Aquidneck Island in winter 2018-19, assuming performance of suppliers, but instead expected it would need LNG operations on Aquidneck Island during the spring and/or summer of 2019 to assist the transmission pipeline company's (i.e., Algonquin's) periodic inspection of its pipe. The Company is exploring whether any options exist that will be large enough to provide supplemental supply on Aquidneck Island for the remainder of the winter.

The letter then mentioned the Company's reliance on the Operational Balancing Agreement and, in effect, continued to maintain that LNG was not needed.

On March 1, 2019, the Company filed a corrected answer with the Division and the Commission in the CHP docket, identifying the forecasting error, and changing the conclusion about the hourly forecast that had been provided on January 25.<sup>145</sup> The Company now disclosed to the Division and the Commission that the hourly limit was not 1,122 Dth/hr. Rather, it was only 1,045 Dth/hr. Most significant, the forecast showed that the limit would have been exceeded during the winter of 2018-19 had a design day occurred during that time. The Company's response then referred to its reliance on the Operational Balancing Agreement with Algonquin to manage capacity across all of its Rhode Island take stations.

Concerned with the response, the Division on March 4 asked another series of questions in this investigation to obtain a better understanding of what transpired with respect to the Company's forecasting. The response to the Division's follow-up questions reflected a significant change in the Company's view:

The Company is re-evaluating its ability to serve additional incremental firm load to Aquidneck Island until such time that additional capacity

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<sup>145</sup> Docket 4755, Division 10-25 Corrected and Supplemental.

resources to delivery [sic] incremental supply to the Aquidneck Island system are in place. Furthermore, the Company has identified a need to recommission the LNG facility at the Newport Naval Station (LNG Facility) to supplement the supply capacity to the Portsmouth take station on the Algonquin system to ensure adequate supply to existing customers and provide supplemental supplies for reliability purposes in the event of another problem with deliveries to the Portsmouth Take Station.<sup>146</sup>

Thus, the Company was now indicating that there was a need to have LNG facilities on Aquidneck Island to assure reliable service to the existing customer load, but this time did not mention the Operational Balancing Agreement in its response.

When the Division probed further to understand why the Company was no longer relying on its Operational Balancing Agreement, the Company verbally informed the Division that Algonquin had sent a notice to all shippers on the Algonquin G-System on January 29, 2019. According to the Company, the Company interpreted the notice as indicating that Algonquin was now limiting the hourly takes of shippers at the take stations to the contractual limits.<sup>147</sup> As a result, the Company maintained that it could no longer rely upon the Operational Balancing Agreement to manage all take stations in the aggregate. Instead, each specific location now needed to be managed in a way that assured that the hourly and daily maximums at the take station are not exceeded, including the Portsmouth take station.

On July 2, 2019, in a separate filing of its amended Long-Range Plan on July 2, 2019, the Company gave a more complete explanation of its new planning process:

On January 29, 2019, Algonquin Gas Transmission LLC (AGT). . . notified the Company (and all AGT customers served by AGT’s G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. . . . Historically, AGT

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<sup>146</sup> Division 3-5, page 2.

<sup>147</sup> After the outage of January 21, 2019, Algonquin sent a notice to all shippers on the G-System on January 29. A copy is provided in Appendix A, labeled as “Algonquin Critical Notice: 1/29/19.”



has not imposed any requirements that its customers manage [sic] meet the calculated hourly flow limits, nor has AGT restricted the Company's ability to balance its overall takes across all take stations. The January 29, 2019 notice expired on April 1, 2019. However, the Company reasonably expects that AGT (Algonquin) may issue a similar notice in the future, or even issue the types of orders described in the January 29, 2019 notice without first issuing another warning. Accordingly, the Company is making planning decisions to be able to comply with any such future orders. Because the Company's peak hour is greater than the [calculated hourly limits], the Company will now need to ensure that it has sufficient deliverability to meet peak hour requirements of its customers.<sup>148</sup>

In effect, the Company was asserting that – because of this January 29 notice – it had to abandon its old way of planning and now plan in a way that assured that hourly limits at the Portsmouth take station would need to be met.

During the investigation, it became apparent to the Division that there was a significant difference of opinion between the National Grid affiliated companies and Algonquin pertaining to the interpretation and interplay among the capacity contracts, tariffs, and Operational Balancing Agreements between National Grid affiliated companies and Algonquin.<sup>149</sup> National Grid affiliated companies, including Narragansett Electric maintained that the Operational Balancing Agreement allowed it to aggregate and balance hourly flows among all its take stations. In contrast, Algonquin maintained that the Operational Balancing Agreement did not.<sup>150</sup> Whether or not the Company did or did not have the right to manage its gas portfolio in accordance with the interpretation of the OBA, however, the Division believes that it was not reasonable for the Company to have been ignoring the hourly contractual flow at the Portsmouth take station.

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<sup>148</sup> Docket 4816, Long-Range Gas Supply Plan (LRP), filed July 2, 2019; pages 16-17.

<sup>149</sup> It is important to reiterate that the Division has no jurisdiction over Algonquin's pipeline business, tariffs, or its contracts. For that reason, it has no regulatory authority to probe the issue relating to the management of the Operational Balancing Agreements by Algonquin, as those agreements might impact hourly and daily limits and the reliability of the G-System. The Division has conferred with staff at the Federal Energy Regulatory Commission regarding the issue, but the Division cannot draw conclusions about the practice under FERC rules and tariffs.

<sup>150</sup> Algonquin Gas Transmission "Response to PHMSA Information Request JH33, March 15, 2016. ("National Grid does not have the contractual right to balance usage amongst various M&R stations on the G-System.")

Further, Narragansett Electric does not dispute Algonquin's authority to limit restrictions to the calculated hourly flows specified in its contracts. The Company only points to historical practices where the Company maintains that Algonquin never imposed such restrictions. But if the Company knew that Algonquin had the right to so restrict flows with properly issued notices and flow orders, it had a duty to assure that its system could sustain service in the event such notices or flow orders were issued.

Just as importantly, given the corrected hourly limit identified after the forecasting error was disclosed, the Division believes there has been an unacceptable design day risk present on the island. In other words, had a design day occurred at any time during the winter of 2018-19 (i.e., average temperature at minus -3 Fahrenheit), Aquidneck Island was at serious risk of a low-pressure condition, even without an equipment failure affecting the Algonquin system. If the Company had been focusing on the hourly limitations and forecasted correctly, it would have revealed the need to have LNG in place on Aquidneck Island for the winter of 2018-19.

## **5.2 Precondition Contributing to the Event: Lack of Contingency Planning for Aquidneck Island**

Hindsight is always 20/20, and a significant lesson learned from the incident is that Aquidneck Island is uniquely vulnerable to low-pressure conditions on the Algonquin G-System. However, there was an event that occurred in 2014 that could have signaled a need for contingency planning for Aquidneck Island, even if such planning was not ordinarily employed for other areas of the Company's system. Such contingency planning also would have strongly suggested the need for vaporized LNG on the island.

### **5.2.1 Low-Pressure Event of March 7, 2014**

In the Division's investigation, the Division learned from the Company that on March 7, 2014, the Portsmouth take station experienced a low-pressure condition from the Algonquin system that threatened service on Aquidneck Island.<sup>151</sup> According to the Company, Algonquin had not received the volume of gas it expected from the Maritimes & Northeast pipeline into Algonquin's system in Weymouth, resulting in the low-pressure problem on the G-System.

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<sup>151</sup> Division 1-9.

On that day, it was only a 31 HDD (i.e., average temperature of 34 degrees Fahrenheit).<sup>152</sup> According to the Company, the system experienced very low inlet pressures into Portsmouth. The Company immediately took steps to bypass one of its regulator stations to mitigate the low-pressure conditions.<sup>153</sup> In addition, since the Navy was taking interruptible gas service for its central heating system and could switch to oil, the Company was able to stabilize the distribution system by interrupting service to the Navy, preserving system pressures to other customers in the Newport area.<sup>154</sup>

Like January 21, 2019, the event on March 7, 2014 did not occur on a design day. However, unlike the January event, the March 2014 event was a relatively normal seasonal day that should not have caused any stress on the distribution system at an average of 34 degrees Fahrenheit. Yet, system reliability was threatened because of conditions on the Algonquin system over which Narragansett Electric had no control.

According to the Company, after the incident, the Company made some improvements to its high-pressure distribution system in one area of Newport to make the system more resilient to lower delivery pressures from Algonquin.<sup>155</sup> The Company, however, did not alter its planning processes to evaluate how contingencies on the Algonquin system could impact Aquidneck Island under various scenarios.

### **5.2.2 No Scenario Modeling in Distribution Planning**

During the investigation, the Division probed the degree to which Narragansett Electric's system planning involves modeling its gas distribution system for contingency scenarios relating to hypothetical failures or other similar incidents that could cause low pressure conditions. In response, the Company indicated that it "typically does not include contingency scenarios relating to hypothetical system failures or other similar low-pressure conditions."<sup>156</sup> In particular, with respect to Aquidneck Island, the Company has never modeled any contingency scenarios that assumed any kind of low-pressure condition occurring on the Algonquin G-System that is out of

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<sup>152</sup> Division 9-2.

<sup>153</sup> Division 1-9.

<sup>154</sup> Division 9-4. The Navy is a dual fuel customer who has the ability to switch to oil for heating if interrupted by National Grid. The Navy was not burning natural gas on January 21, 2019, having already switched to oil for the entire day.

<sup>155</sup> Division 9-6.

<sup>156</sup> Division 7-1.

the Company's control. In fact, the Company stated: "The modeling of contingency scenarios that assume a low-pressure condition occurring on the Algonquin G system or any other transmission lateral out of the Company's control is not part of the reliability planning performed by the Company."<sup>157</sup> The Company further stated:

The [Company's] approach to system modeling and planning assumes that transmission pipeline companies will deliver gas to the take stations at pressures equal to at least the minimum guaranteed contractual pressure. It is unreasonable to plan the system for 'worst case' scenarios similar to what occurred on January 21, 2019, where [Algonquin] delivered gas to the Portsmouth take station at pressures far below the contractual minimum pressure.<sup>158</sup>

Modeling contingency scenarios are a part of the gas business to assess impacts from the loss of supply. In fact, there are industry guidance documents published by the American Gas Association that confirm the desirability of such a practice.<sup>159</sup> While the Division is not drawing definitive conclusions about the extent to which the Company should be modeling contingencies across its *entire* system, the Division believes the Company should be modeling scenarios for Aquidneck Island that consider the effects of potential low-pressure conditions on the Algonquin system. Given (i) the March 2014 event, (ii) the configuration of the gas distribution system in Newport, and (iii) the vulnerability of Aquidneck Island to low-pressure conditions on G-System,<sup>160</sup> the Division believes contingency modeling should have been a part of its processes.

## **Section 6.0 Additional System Vulnerabilities**

In the course of the investigation, the Division also evaluated other conditions existing prior to the event and the Company's preparedness for the emergency. This review also identified deficiencies in the Company's preparedness. It is important to note that the Division does not

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<sup>157</sup> Division 7-2.

<sup>158</sup> Division 7-6.

<sup>159</sup> See the Chapter 5 on "Network Simulation" in *Gas Engineering & Operations Practices (GEOP) Series, Volume III, Distribution* (American Gas Association, Arlington VA – 1990) (p. 177, Table 35)

<sup>160</sup> See Division 13-3 and Division 15-2.

believe that the deficiencies identified in this section necessarily played a role in contributing to the low-pressure problem or causing the curtailment on January 21. Nevertheless, the Company should remediate the issues identified here.

### **6.1 Dispatching and Outage Mapping Processes**

During gas emergencies, accepted utility practice suggests that a utility should have an efficient process that allows timely visibility to the areas of the service area from which “no gas” calls are being received. In turn, as the calls arise, there should be a mapping process that provides a clear picture of what is happening on the system.

The Company had already identified the need to improve its capabilities for its field technicians (among other process improvements) and has had a comprehensive gas transformation plan underway that is designed to improve the capabilities of its field technicians to identify, respond, and report on gas outages.<sup>161</sup> But the new system was not yet in place in January. Instead, an old pre-existing manual process was still being employed. The Company had a system in place to receive calls, generate orders for scheduling technicians, and send technicians to the location of gas outages. However, the Division believes the system was only adequate to address “no gas” calls in the ordinary course of business.<sup>162</sup> It was not effective for addressing emergency conditions occurring on a more widespread basis.

As the low-pressure condition on the Algonquin system began to affect service to consumers on Aquidneck Island in the late morning of January 21, 2019, the Company began to receive phone calls that were taken by the Company’s Gas Dispatch system.<sup>163</sup> The number of “no gas/poor pressure” calls started small. But the count grew quickly in the afternoon hours. It is clear that the Company was aware of the pressure drop in the low-pressure system in Newport, but it is equally apparent that the command team did not have visibility to geographical scope of the outages in the low-pressure system as the outage calls increased.<sup>164</sup> As the calls were received, they were recorded in the Company’s Customer Service System (“CSS”).<sup>165</sup> According to the Company, technicians were sent to some of the locations where the calls originated to shut off

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<sup>161</sup> Division 19-1, 19-2, and 19-3.

<sup>162</sup> See the description of the process provided in Division 17-5.

<sup>163</sup> Attachment DIV 1-14.

<sup>164</sup> See Division 17-7 and 17-8, compared to Division 1-1, page 4.

<sup>165</sup> Division 17-5.

service. But there was no system in place to be able to track the location of the outages for purposes of assessing the scope of the problem as events unfolded.

The Company maintains that Gas Dispatch “was in frequent communication with the Company’s decision makers managing the response to the events of January 21, 2019.”<sup>166</sup> According to the Company’s narrative of events, and as quoted earlier:

The Company expected that areas of no gas calls would occur on the southern peripheries or end points and crews could isolate those segments and maintain supply to the core integrated district. At 4:30 p.m., Dispatch provided a list of no gas calls. Engineering then prepared a map of the outages. Narragansett Electric then overlaid that outage map on the entire integrated low-pressure system and immediately recognized that the outages spread across all segments, including the northern and central segments.<sup>167</sup>

By the time the system was mapped, the Company could only confirm what now had become apparent about the widespread nature of the impact.

It does not appear to the Division that it would have made a material difference if the Company had visibility to the location of the outages earlier in time. The Company maintains: “If the emergency response command had completed the mapping earlier in the day, it would not have had a material impact on the shutdown process because the pace of the pressure drop did not allow for sufficient time to isolate an area of the integrated low-pressure system to prevent the additional outages on the other parts of the system.”<sup>168</sup>

In addition to the lack of an automated mapping process, the Company’s response to the outage calls on the island was not sufficiently prompt to provide the Company awareness of its system. The Company stated that 93 customer meter services employees were available to respond to outage calls on Aquidneck Island during the course of the day. While CMS technicians were not the only employees responding to the event, they play an important role in addressing customer

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<sup>166</sup> Division 17-7.

<sup>167</sup> Division 1-1, page 4.

<sup>168</sup> Division 17-8.

shut offs.<sup>169</sup> According to the Company, at 10:45 am the “Customer Meter Services” (CMS) group was notified of the emergency conditions on Aquidneck Island.<sup>170</sup> At that point, CMS management personnel began to reallocate resources to the island in order to investigate the “no gas/poor pressure” orders and shut off the services at those locations. But the arrival of the technicians did not happen rapidly. As described in the sequence of events, the number of technicians was relatively small as the calls first came in around 11:09 am and it took a number of hours for more technicians to arrive over the course of the afternoon.<sup>171</sup>

After the call went out, there were only 10 CMS vehicles on the island by 12:15 pm.<sup>172</sup> By 2:13 pm, there were only 27 CMS vehicles on the island, a full three hours from when the first “no gas” call was received. By 3:55 pm, there were 29 CMS vehicles. It was not until after 4:00 pm that the number of CMS vehicles finally started rising significantly higher.<sup>173</sup> But that was over five hours from when the first call went out to dispatch all of the 93 CMS employees the Company maintains were available.<sup>174</sup> Moreover, the Company’s system of recording the activity of arriving at a customer account and shutting off the service was manual, through which the technicians used manual outage cards. There was no system in place for the technicians to electronically report the activity as it occurred. The lack of a coordinated modern-day communication system between technicians in the field and the emergency command center also appears to have hindered leadership’s visibility to what was occurring in the field

The Company does not know today how many individual customer meters were shut off during the course of the late morning and afternoon of January 21 prior to the curtailment order. When the Division requested the Company to provide the number of customers who were shut off between 11:00 am and 6:30 pm, the Company stated in response: “The Company cannot provide a specific count of how many locations were shut off between 11:00 am and 6:30 pm because the

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<sup>169</sup> There were many other employees, including Instrumentation and Regulation, Field Operations, and other employees performing various duties. See, for example, Division 17-1.

<sup>170</sup> Division 17-1.

<sup>171</sup> See Division 17-12 and accompanying Attachment 17-12-1.

<sup>172</sup> The Company was unable to give the Division a count of the number of CMS technicians as they arrived on the island. As a result, a proxy was used to estimate the arrivals by tracking the vehicles. The Company maintains that some vehicles may have had two technicians. Given the limited data, the Division is using the vehicles as a proxy as well.

<sup>173</sup> Division 17-12.

<sup>174</sup> Division 17-1.

manual outage cards are not stored in searchable format that can be easily aggregated.”<sup>175</sup> When the Division pressed further on this issue, the Company stated: “Because the manual outage cards are organized and stored geographically by outage zone, not by date, the Company cannot readily determine how many cards were filled out on January 21, 2019.”<sup>176</sup> In fact, there is not even a place on the outage card for a technician to write down the actual time that a shutoff occurred.<sup>177</sup>

Narragansett Electric maintains that “most gas utilities use manual outage card systems or similar systems when responding to gas emergencies,” which the Company apparently confirmed with the American Gas Association.<sup>178</sup> The Company indicates that many utilities are taking steps to modernize. The event here in Rhode Island should be an industry wake-up call to expedite that modernization process.

During its last rate case filed in 2017 and completed in the summer of 2018, the Company proposed substantial system improvements in the gas business that contemplated changes across all of its jurisdictions, including Rhode Island, Massachusetts, and New York.<sup>179</sup> This initiative, referred to as the “Gas Business Enablement” (GBE) program, has many important features, one of which is to put in place sophisticated and automated systems for use by field technicians. It also will link the location of outage calls directly to its GIS maps on a real time basis. The proposal was reviewed and supported by the Division, and ultimately approved by the Public Utilities Commission. The system is scheduled to be in place for the winter of 2019-20. The Division is supportive of the Company’s ongoing efforts in its GBE program to modernize its emergency response plans and processes, recognizing the need to monitor implementation and system integration with other Company procedures. But the system was not in place on January 21. Nevertheless, the Company was aware that it had an antiquated system in use for the winter of 2018-19. As such, it could have implemented provisional emergency response plans that considered the antiquated nature of the system by implementing provisional mapping processes during the interim.

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<sup>175</sup> Division 18-8.

<sup>176</sup> Division 18-12.

<sup>177</sup> The Division requested a sample of the cards, a copy of which is attached to Division 18-12.

<sup>178</sup> Division 21-4.

<sup>179</sup> See the testimony beginning at page 82 of the linked file, found at:

[http://www.ripuc.org/eventsactions/docket/4770-NGrid-Book7\(ISP-GBE\).pdf](http://www.ripuc.org/eventsactions/docket/4770-NGrid-Book7(ISP-GBE).pdf)



## 6.2 Inability to Sectionalize

In cases where it becomes impracticable to shut off services individually in a timely manner when “no gas” calls are received, another industry-standard action available to gas utilities under certain circumstances is to identify the location of the outages as rapidly as possible and take steps to isolate (or “sectionalize”) the affected areas. By sectionalizing, the action is intended to limit the impact from spreading, by shedding load to boost pressures to the remaining customers (among other purposes). One important question that the Division posed to the Company was why the Company did not attempt to sectionalize portions of the low-pressure system in Newport instead of curtailing the entire system at once.<sup>180</sup> In fact, the Company did “sectionalize” the portion of the low-pressure system located in Middletown early in the day when it shut off the regulator on Walcott Avenue serving the low-pressure system in Middletown shortly after noon.<sup>181</sup> But, no further sectionalizing took place for the remainder of the day.

The Company’s answers to this question, however, at times were contradictory. Initially, during interviews, the Narragansett Electric Vice President for Asset Management told the Division that the Company could not sectionalize Newport because it did not have the necessary valves in the low-pressure system in Newport to isolate areas of the system.<sup>182</sup> Yet, when the Company answered written questions about the extent to which the low-pressure system in Newport could be sectionalized, the response stated that the Company “can sectionalize the low-pressure system in Newport during emergency conditions if there is a confined area experiencing the emergency conditions that necessitate the shut off.”<sup>183</sup> Another response even stated that there was a process in place for isolating the system.<sup>184</sup> The Company then provided data indicating that there were 449 emergency shutoff valves in Newport.<sup>185</sup> The Division followed up with another written information request, pointing out what appeared to be a contradiction between the interview with the Vice President and the written answers that followed from others.

At a later interview session, Company representatives eventually conceded that there was no practical way to sectionalize the low-pressure system in Newport.<sup>186</sup> None of the technicians

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<sup>180</sup> See Division 16-1, Division 18-1, and 18-2.

<sup>181</sup> Division 1-1, page 3.

<sup>182</sup> Interview, May 20, 2019.

<sup>183</sup> Division 18-2.

<sup>184</sup> Division 18-3.

<sup>185</sup> Division 18-4.

<sup>186</sup> Interview, July 18, 2019.

that had been dispatched to Aquidneck Island had any access to maps or other data that identified shut-off valves in the area.<sup>187</sup> Another response also conceded that the shut-off valves identified in the earlier response “are not associated with specific sectionalizing districts that would require annual maintenance to ensure they are operational.”<sup>188</sup> Stated succinctly, there was never any possibility that that Company could have sectionalized areas of Newport as the outage calls mounted since the Company may have had valves in place on the gas distribution system but the Company had not developed a sectionalizing plan to maintain and utilize these valves in times of emergency to cut off portions of the gas system. The Company’s explanation for the inconsistent written responses was that the person sponsoring the answer took the question literally and simply maintained that it was “technically” possible, even if not practically possible.<sup>189</sup>

One of the recommendations in this report is for the Company to perform a study to determine the feasibility, costs, and effectiveness of establishing some level of sectionalizing capability on the low-pressure system in Newport, as it could be critical to shutting off sections of the gas system in other types of gas emergencies.

### **6.3 The National Grid Organizational Structure**

During the course of the investigation, the Division also sought to obtain a more complete understanding of how National Grid in Rhode Island manages its gas distribution business. The gas distribution business in Rhode Island is a relatively small portion of the National Grid business in the United States. By way of comparison, National Grid has over 900,000 gas distribution customers in Massachusetts and over 1.8 million gas distribution customers in New York. In contrast, Rhode Island has only approximately 250,000 gas distribution customers.

National Grid utilizes a shared gas organization to provide services across jurisdictions. While there are many gas distribution employees who work only in Rhode Island, the gas distribution business is essentially managed through a multi-state organizational structure.<sup>190</sup> This has some advantages. One is efficiency and lower cost, as systems and processes are shared across more territory. Another is the sharing of best practices across lines from one management structure. However, there are downsides as well.

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<sup>187</sup> Division 18-10.

<sup>188</sup> Division 18-11.

<sup>189</sup> Interview, July 18, 2019.

<sup>190</sup> Division 1-12 & Attachment DIV 1-12 pages 1-3.

Specifically, the cross-jurisdictional organizational structure can result in a management structure through which there is no single executive who has authority and visibility over the broad scope of gas distribution-related services, operations, risks, and processes that were exclusive to Rhode Island. In fact, the Company conceded during interviews that there is no one person who has a comprehensive understanding of the gas distribution business in Rhode Island.

Another organizational issue relates to the gas capacity procurement function. Oddly enough, while the organizational structure has gas distribution and LNG operations controlled through a chain of command leading up to one person in charge of all U.S. gas operations, the capacity procurement function resides elsewhere. Within the structure, the Energy Procurement group responsible for assuring adequate interstate pipeline capacity reports up to the National Grid senior executive in charge of a function referred to as the “Electric Transmission, Generation & Energy Procurement Business Unit.” The mission statement of that function states on the organizational chart:

The Transmission, Generation and Energy Procurement business unit is focused on driving our evolution to being a leading transmission company. The unit is accountable for managing the company’s relationship with the Federal Energy Regulatory (FERC), ensuring our compliance with all FERC regulations, and, in partnership with the Strategy & Regulation Function, setting our FERC regulatory strategy. In addition, this business unit is also responsible for the safe and efficient operation of our power generation plants and for procuring natural gas and electricity for our customers.<sup>191</sup>

The energy procurement function does not appear to link up in a rational way to the overall mission of this particular business unit.

The jurisdictional President in Rhode Island appears to have some executive responsibility for the Rhode Island electric and gas distribution businesses. But he does not have the employees in gas operations directly reporting to him.<sup>192</sup> The Company maintained during interviews that this

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<sup>191</sup> See Attachment DIV 1-12, page 6.

<sup>192</sup> See the organizational charts in Attachment DIV 1-12 pages 1-3.

can be addressed by implementing frequent and effective communication processes. The President, however, does not have any gas distribution experience or anyone who directly reports to him with gas distribution experience to assess whether the broad menu of services being provided by the cross-jurisdictional gas operations of the National Grid USA Service Company are effective for Rhode Island to address local concerns adequately.

Given the circumstances and the relative size of the Rhode Island service area compared to the larger multi-state organization, the Division believes that National Grid should assign an experienced gas distribution Vice President (or similar level employee), with broad knowledge of the gas distribution business, to the President of Narragansett Electric. This high-level employee should be given the responsibility to manage the relationship of the Rhode Island gas operations with the larger U.S. gas business and provide insight and assistance to the President (exclusively focusing on Rhode Island). Absent this experience and perspective, the Division believes that the President is “flying blind” to the realities of what may be needed to continuously improve gas service for Rhode Island consumers. This role also would serve well to provide appropriate focus on the regulatory and other business relationships within the state that are needed to operate an effective local gas distribution business. Further, as environmental and energy policies advance more climate change initiatives that directly affect the gas distribution business, it will be critical that there is an executive with exclusive local focus on the Rhode Island gas business.

#### **6.4 Lack of a Comprehensive “After-Action Review”**

The Division believes that a prudent utility will always perform some form of self-evaluation after-the-fact when an unprecedented event occurs that created great risk to public safety. During the interview process, National Grid personnel stated that it has a practice of performing such “after-action reviews” to assess the performance of its affiliates, including Narragansett Electric, following major emergency events. The Company identified such a review that it performed in February of 2019 relating to the restoration process following the curtailment.<sup>193</sup> However, the review was limited to the Company’s response from the period when the curtailment occurred to when restoration was completed. Other than an uncirculated rough

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<sup>193</sup> Attachment DIV 21-2. The “Emergency Planning After Action Review” is dated April 26, 2019, but the sign-in sheets show the process underway on February 8, 2019. The Company maintains that this document contains confidential commercial information which is exempt from public disclosure.

draft document dated January 22, 2019,<sup>194</sup> the Company has provided no reports, memos, presentations, board materials, or any other documentation that reflects any level of self-evaluation of how the Company responded to the low-pressure condition as the effects unfolded on January 21, 2019 prior to the curtailment decision in the early evening of that day.

Narragansett Electric does have an “Emergency Response Plan” (ERP) which includes a section on the need to perform after-action reviews.<sup>195</sup> The section unequivocally recognizes the need to perform such reviews.<sup>196</sup> The ERP also contains a template for documenting after-action reviews. The template contains a section entitled “Preparatory Actions.” However, when the Company documented its review, the report skipped any analysis of “Preparatory Actions” and went directly to the outage restoration process. It appears to the Division that this may be the result of the Company being concerned that any self-critical document might be prejudicial to the Company should there be any lawsuits in the future over the events of that day.<sup>197</sup> The Division believes this lack of self-evaluation is unacceptable and inconsistent with good utility practice.

## **Section 7.0 Failure to Notify the Division of the LNG Plant Outage**

While certain imprudent actions and inactions of the Company do not represent violations of a specific Division rule or regulation, the Division has identified one instance of a rule violation based on the Company’s failure to provide a telephonic notification to the Division of the emergency shutdown of an LNG facility. (815-RICR-20-00-1, Section 1.14 A.3.) For that reason,

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<sup>194</sup> Attachment DIV 4-5-1, pages 8-11 & 19-23. The document was entitled “Algonquin Supply Newport Outage – Preliminary Lessons Learned” and was authored by the Director of the Gas Control Center. There were two drafts of the “Lessons Learned” document. The first draft contained a vague reference to the Providence LNG plant operations. However, the reference to the Providence LNG plant was deleted in the second draft. Both drafts are dated January 22, 2019.

<sup>195</sup> Division 21-1.

<sup>196</sup> Attachment DIV 21-1, page 179. (Note: The Company maintains that the document contains references to Critical Energy Infrastructure Information and, thus, is not available to the public.)

<sup>197</sup> An evidentiary rule in Rhode Island relating to the admissibility of “Subsequent Remedial Measures” in civil litigation allows evidence of subsequent remediation to prove an admission of fault. Apparently, the conventional doctrine in many other states is to exclude such evidence to prove admission of fault in order to encourage potential defendants to remediate problems before they cause another injury. Rhode Island is in the minority and allows the admission of such evidence. The Division has not researched this point, but there is a law review article on the subject. See Fielding, Brian (2009) “Rhode Island’s 407 Subsequent Remedial Measure Exception: Why it Informs What Goes Around Comes Around in Restatements (Second) & (Third) of Torts, and a Modest Proposal,” *Roger Williams University Law Review*: Vol. 14: Issue 2, Article 3, found at: [https://docs.rwu.edu/cgi/viewcontent.cgi?article=1400&context=rwu\\_LR](https://docs.rwu.edu/cgi/viewcontent.cgi?article=1400&context=rwu_LR)

the Division will issue a Notice of Probable Violation and issuing a fine of \$39,000 to the Company. The specifics of the non-disclosure are described below.

Following January 21<sup>st</sup>, no one at Narragansett Electric informed the Division about the LNG facility shutdown in Providence. During that time, Company personnel attributed the low-pressure condition solely to the Algonquin valve malfunction that occurred in Weymouth. The Division then commenced its investigation not knowing that the Providence LNG facility had experienced a shutdown. The Division sent its first set of questions to the Company on February 5. The first question the Division asked was for the Company to provide a narrative of events.

Before the Division received a response to the its question, PHMSA held a conference call with the Division on February 21<sup>st</sup> to share information with the Division. During the call, PHMSA informed the Division about the shutdown of the Providence LNG facility that impacted the G-System pressures.<sup>198</sup> After receiving this information, the Division expected to learn more about the Company's understanding of the impact of the LNG shutdown on Aquidneck Island.

On February 28, the Company filed its responses to the Division's first set of information requests. In the narrative of events, the response said nothing about the shutdown of the Providence LNG facility.<sup>199</sup> In an attachment, the Company provided copies of some event logs. In one of the event logs, there was a reference to the Providence LNG shutdown.<sup>200</sup> The log contained a short comment: "Providence LNG called – shut down is currently trying to come back online 04:48" The log then contained appended comments updating the situation during the morning. Other than the copy of the event log, the Company did not inform the Division. In a 5-page response to a question that was intended to obtain a complete explanation of everything that occurred from the point of detecting low-pressures, the long narrative never mentioned anything about the Providence LNG facility or how the control room personnel were interpreting its impact at the time.<sup>201</sup>

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<sup>198</sup> On March 1, 2019, an article also appeared in the *NewportRI.com*, in which a representative from Enbridge disclosed the fact that the Providence LNG facility had experienced the outage. See:

<https://www.newportri.com/news/20190301/enbridge-points-to-national-grid-other-sources-for-newport-gas-outage>

<sup>199</sup> See Division 1-1.

<sup>200</sup> See Division 1-2, Attachment DIV 1-2.

<sup>201</sup> Division 1-1.

Not having received any other description of the matter, the Division immediately submitted another set of questions to the Company to explore the issue. One of the questions asked specifically why the Company never informed the Division formally or informally about the emergency shut down of the Providence LNG facility. The Company's response is quoted below:

The Company did not formally or informally notify the Rhode Island Division of Public Utilities and Carriers (the Division) on January 21, 2019, or during the weeks that followed, that the NGLNG plant in Providence experienced a shut-down on the morning of January 21, 2019, because: (1) the Company believes that failures and problems in the Algonquin Gas Transmission, LLC system caused the low pressure condition that led to the shutdown of the low pressure gas distribution system on Aquidneck Island, and (2) the Company did not and does not believe that the NGLNG facility's temporary inability to send out gas to the Company's distribution system caused the low pressure condition that led to the shutdown of the low pressure gas distribution system on Aquidneck Island.<sup>202</sup>

The Company's February 28<sup>th</sup> response is not satisfactory given other documentary evidence the Division subsequently collected from National Grid and its affiliates.

On April 9, in response to a Division request for emails on the subject, the Company subsequently provided a copy of an email dated January 21, 2019. The email was sent at 10:18 am, from the manager of the control center (Paul Loiacono) who was on duty that morning, to his boss Mr. Richard Delaney, describing the low-pressure event as it was unfolding. This was approximately 45 minutes after the control center employee had spoken with an Enbridge employee on the phone about the Weymouth valve failure. In pertinent part, the email stated the following:

The loss of the LNG had an immediate impact to our distribution system, the 200 psi line quickly dropped out to 100 psi, and the 99 psi system began to sag off as well. We picked up flow at Crary St and the loss of LNG

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<sup>202</sup> Division 2-10.

naturally picked up the flow at Wampanoag Trail. This also had an immediate effect on the AGT G-System which supplies down to Portsmouth [sic] GS on Aquidneck Island. The inlet pressure to Portsmouth has collapsed from 459 psi at the time of the shutdown down to 90 psi. We have I&R standing by on the island top [sic] bypass reg stations if needed.

Coupled with the plant shutdown was an issue that AGT was having up in Massachusetts that contributed to the G-System suffering. They had a frozen valve on the Hub Line (Maritimes NE) supply in Weymouth Ma. They have since bypassed this valve and pressures have recovered nicely in the Weymouth – Milton area of MA but will likely take several hours to show any relief on Cape Cod and Rhode Island which are fed from the G-System.<sup>203</sup>

The Company also provided a second email sent on the day of the event, January 21, 2019, at 3:22 pm, from Richard Delaney to Ross Turrini, National Grid’s Chief Gas Engineer overseeing all of National Grid’s gas operations.<sup>204</sup> The email forwarded Mr. Loiacono’s email from 10:18 am that described the impact on the G System from the LNG shutdown, with the following note:

Ross, Providence is back on line. Pressure have not started to recover at Portsmouth. Rich.

Another email sent on January 21, at 4:54 pm by and to employees in the Energy Procurement Business unit contained the following observation:

NGLNG has been struggling all day . . . it tripped off earlier today . . . . killed pressures. . . which were already suffering as there were low inlet pressures from AGT.<sup>205</sup>

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<sup>203</sup> Attachment DIV 4-4-1, page 39. See also Division 2-2 Supplemental and accompanying letter.

<sup>204</sup> Attachment DIV 4-4-1, page 39.

<sup>205</sup> Attachment DIV 4-4-1, page 45.



While this email did not involve the control center, it reflected knowledge of the Company that the shutdown of the Providence LNG facility may have had an impact on the Algonquin G-System.

The Company also provided copies of some handwritten notes of a phone call that occurred between the jurisdictional President of the Massachusetts gas distribution company, Marcy Reed, and Bill Yardley, a high-level executive of Enbridge.<sup>206</sup> The notes are transcribed below:

Bill Yardley 11:18 am 1/30/19, - (called me b/4 - would call him)

Prov LNG – everything went haywire after that

PHMSA, FERC, etc asking for their data

Weymouth – nothing to do w/ this

Tried to not be public, but RWT<sup>[207]</sup> comment makes it difficult

d/n want to throw us under the bus

RWT [illegible] re: Weymouth – its all folks have grabbed onto Enbridge

BOD – pushing BY to defend himself Not running to press, but basically

need to call PHMSA, FERC Yesterday data – o/s [illegible] – it'll be

compelling to all that your overtakes are the problem. Not sure why

PHMSA involved – s/b FERC

There is another email that was provided to the Division on April 9. The email was dated January 31, 2019, sent by Mr. Turrini at 10:26 am to another employee, copying upper management officials at National Grid.<sup>208</sup> The email was Mr. Turrini's comment on a proposed draft communications document. Mr. Turrini's note said:

Jim,

We should tone down what we say about the root cause, as we need to fully understand all the data and the exact root causes (as there will probably multiple [sic], their valve failure, utilities over taking from pipelines and

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<sup>206</sup> Attachment DIV 4-7-1, page 3. See also Division 2-18.

<sup>207</sup> RWT are the initials of Ross Turrini, Senior Vice President for Gas Operations of National Grid.

<sup>208</sup> Attachment DIV 4-6-1, page 6.

our LNG facility). I am back in the office on Monday. If you need to talk to me I can be reached on my cell phone tomorrow afternoon. Ross<sup>209</sup>

Given the documents provided by the Company to the Division, it is apparent that Company management knew immediately on January 21 that the shutdown of the LNG plant impacted the Algonquin G-System and gas pressure at Portsmouth. The Division questioned the Company on this issue in interviews, including examination of Mr. Turrini, who steadfastly maintained that he believed from the beginning of the incident that the Providence LNG facility did not contribute to the causes of the outage, even though other employees working under his line of authority expressed a different view at the outset of the event.

Mr. Turrini maintained during the interviews that there was no intention on his part or the Company to deliberately conceal the fact that an outage at the LNG facility occurred. In fact, Mr. Turrini stated that he believed at the time that the Division was aware that a shutdown had occurred. For that reason, he did not believe it was necessary to formally or informally contact the Division to disclose that a shutdown had occurred.

Notwithstanding Mr. Turrini's explanation during the interview, the Division has regulations that require the gas distribution company to disclose to the Division by telephonic notification of any incident involving an "emergency shutdown" of an LNG facility. 815-RICR-20-00-1, Section 1.14 A.3.<sup>210</sup> While the LNG facility itself is owned by an affiliate of the gas distribution company that is regulated by the Division, the LNG facility injects natural gas directly into the gas distribution system over which the Division has regulatory authority. For that reason, when the LNG facility shut down on January 21 – one of the coldest days of the year since 2005 – Narragansett Electric had a legal duty under the Division's regulations to notify the Division. However, the Company did not notify the Division within a reasonable time after the occurrence.

Given this noncompliance with Division regulations, the Division will be serving a Notice of Probable Violation on the Company, including a fine that is calculated at the statutory maximum

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<sup>209</sup> It appears to the Division that Mr. Turrini's note on January 31, describing the probable root cause to be "multiple," was correct. Yet, the Company has never been willing to concede this in any of its responses or interviews with the Division.

<sup>210</sup> The event log from the National Grid control center described the incident as an "ESD," which the Company has confirmed means "emergency shut down." See Division 2-11.

of \$1,000 per violation. Counting each day from the event as a separate violation, there were 39 days from January 21 to February 28, when the Division received the event log reference from the Company that identified the fact that a shutdown had occurred. This equates to a fine of \$39,000.

As described in the next section, this penalty represents only one portion of the potential financial impact of the outage on Narragansett Electric and National Grid shareholders.

## **Section 8.0 Recommendations**

This section of the Report details recommendations of steps for Narragansett Electric to undertake to enhance the reliability of the gas distribution system.

### **8.1 Positive Observations Regarding the Performance of Narragansett Electric**

The purpose of the Division's Report was to identify the cause(s) of the outage, determine whether any regulations were violated, and make recommendations for future improvements designed to assure that an event like this does not occur again. For that reason, much of this Report evaluates the events and the Company's performance with a critical eye. However, in the interest of providing the public complete information, there are some areas in which Narragansett Electric performed well and that should be acknowledged.

First, once it recognized the gravity of the situation in the late afternoon of January 21, Narragansett Electric made the correct decision to curtail service for the entire low-pressure system in order to protect public safety. The Company acted decisively when it became clear that no other options were available, even though it would lead to an unprecedented outage event that would negatively affect customers and, potentially, the company's reputation. To do otherwise would have endangered public safety.

Second, Narragansett Electric should be commended for preserving the high-pressure systems on Aquidneck Island. The steps it took to maintain adequate pressures to those segments helped to avoid what could have been a major catastrophe had the high-pressure systems serving critical facilities on that extremely cold day been lost.

Third, Narragansett Electric responded promptly and robustly in the days following the curtailment. A virtual army of technicians and staff descended upon the Newport area to complete the restoration process meter by meter in difficult conditions.

Finally, once the restoration was complete, Narragansett Electric voluntarily reimbursed certain categories of costs incurred by numerous customers who had been inconvenienced and faced with hardship.

## **8.2 Recommendations and Regulatory Expectations**

The Division has identified deficiencies in Narragansett Electric’s planning, organization, and internal processes. In parallel with the investigation, Narragansett Electric began to address some areas of need. Below is a description of the Division’s recommendations and expectations for future action, the first three of which have already been adopted by the Company:

- (1) **Improvements in Gas Long-Range Planning**: Prior to January 21, 2019, the Division had already identified problems with the way that Narragansett Electric performs its long-range capacity planning and had taken steps to recommend improvements to that planning process. In addition, the Investigation confirmed forecasting deficiencies, described in this Report. Narragansett Electric has now formally agreed with the Division to alter its planning processes to include hourly peak demand at each gas take station serving Rhode Island. The company has implemented this recommendation in a filing made in Commission Docket 4816 on July 2, 2019.<sup>211</sup>
  
- (2) **Winter Deployment of LNG Facilities on Aquidneck Island**: Considering the event of January 21 and the Division’s scrutiny, Narragansett Electric has agreed to deploy temporary LNG facilities on Aquidneck Island each winter to address the need to have capacity that meets hourly peaks, including on the gas design days that have the greatest demand for gas. The presence of LNG facilities will also serve as a contingency resource on non-design days in the event of a low-pressure condition occurring on the Algonquin system in the future.

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<sup>211</sup> The plan can be found at: [http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20\(7-2-19\).pdf](http://www.ripuc.org/eventsactions/docket/4816-NGrid-Compliance%20with%20Division%20(7-2-19).pdf)

- (3) **Evaluation of Reinforcing the Lateral Serving the Portsmouth Take Station:** Aquidneck Island is served by only one take station at Portsmouth, which, in turn, is served by a single six-inch lateral pipeline.<sup>212</sup> However, the Algonquin G-System leading up to the lateral has both twelve-inch and six-inch pipes. Narragansett Electric should engage with Enbridge to determine the feasibility of reinforcing service into Portsmouth by having Algonquin add a twelve-inch pipe in parallel with the existing six-inch pipe.
- (4) **Implementation of Demand Response Initiatives on Aquidneck Island:** In addition to reinforcing the system, the Division recommends that Narragansett Electric implement a demand response program designed to reduce peak hourly demand at the Portsmouth take station. Such a program also could mitigate or prevent the effects of low-pressure conditions during cold weather events that might threaten reliable service.
- (5) **Contingency Scenario System Modeling and Emergency Response Planning:** Given the vulnerability of Aquidneck Island to gas low-pressure conditions, the Division recommends the Company implement a scenario-based contingency planning process. Such process should include an annual scenario modeling and planning process that leads to the development of a detailed emergency response plan. The Division recommends that Narragansett Electric work with the Division to develop a process reasonably acceptable to the Division to establish this process, which would include updates to the Division.
- (6) **Evaluation of the Feasibility of Establishing Sectionalizing Districts in Newport:** During the investigation it became clear that the low-pressure distribution system in Newport – as a practical matter – was not capable of being sectionalized to isolate problems on the system. The Division is requesting that Narragansett Electric conduct a thorough study of this issue to evaluate the feasibility of establishing sectionalizing districts for Aquidneck Island and other potential low-pressure risk areas across Rhode Island. The study should consider the costs and benefits of such an endeavor. The Division is requesting the Company provide such study to the Division.

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<sup>212</sup> See Division 13-3.

- (7) **Establishing a Process for Emergency Mobilization of LNG:** As the events unfolded on January 21, Narragansett Electric made a significant effort to mobilize LNG to Portsmouth on extremely short notice. By the time temporary LNG equipment arrived, it was too late. The Division recommends that Narragansett Electric study the feasibility and practicality of putting in place a system through which LNG can be mobilized on short notice, and report back to the Division on the analysis. While LNG will be in place on Aquidneck Island in the future, it is conceivable that there could be an emergency condition elsewhere in the system, where emergency deployment capability could be critical to system stability.
- (8) **Interim Mapping and Tracking Process:** As explained in the Report, Narragansett Electric is in the process of implementing new systems that will allow greater real-time visibility to the location of gas outages. The system will link the outage calls to the GIS maps of the distribution system. To the extent the new system is not fully operational for the winter of 2019-20, the Division recommends the Company employ a manual mapping and tracking process to provide visibility to outages as they occur and updates when an area of the system appears to be affected by emergency conditions. This interim solution should not only be employed for events on Aquidneck Island, but should be incorporated into emergency response planning across the state-wide system.
- (9) **After-Action Review Processes:** The Division has noted that Narragansett Electric has not produced any documentary evidence that it has performed a thorough “after-action” review of what occurred between the time the low-pressure condition was identified on January 21 through to the time that the Company decided to curtail service in the low-pressure system in Newport. The Division recommends that the Company establish a systematic review process that occurs, without delay, following a significant event affecting public safety and the reliability of gas service. Any such review should be submitted to the Division. Narragansett Electric should conduct such an after-action review for the January 21, 2019 event, taking into account the deficiencies identified in this Report.

(10) **Improved Communications Between Narragansett Electric and Algonquin:**

On January 21, when the Providence LNG facilities experienced the shutdown, there was no immediate communication to Algonquin to notify their control center of the shutdown. The Division recommends that National Grid and Enbridge establish communication protocols for the real time notification of a shutdown of the Providence LNG facility or other similar events that have a potential effect on the Algonquin system.

(11) **Appointment of a Vice President for the Rhode Island Gas Business:** As

described in Section 5.3 of this Report, the Division has concerns about the organizational structure of the gas business in Rhode Island. Specifically, there is no executive level person in Rhode Island who has gas expertise and responsibility for the management of the gas business in Rhode Island. For the reasons given in that section of this Report, the Division is recommending the appointment of a Vice President-level (or equivalent level) executive, reporting directly to the jurisdictional President. This Vice President would have focused responsibility, ownership and accountability for all aspects of gas service in Rhode Island.

(12) **Implement the recommendations of the U.S. Pipeline and Hazardous Materials Safety Administration report on this incident.**

### **8.3 Ratemaking and Cost Recovery**

In response to an investigation question, Narragansett Electric has estimated that the incremental costs it incurred as of September 30, 2019 from the January 21 outage were in excess of \$25 million. These costs are itemized below. The complete response from Narragansett Electric is included in the Appendix.<sup>213</sup>

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<sup>213</sup> Division 22-1

<b>Item</b>	<b>Cost category</b>	<b>Amount</b>
1	Internal company labor including overtime	\$8.5 m
2	Contractors	\$9.3m
3	Meals, lodging and logistics (materials and transportation)	\$3.8m
4	Customer claims	\$2.0m
5	Claims reserve	\$3.0m
6	Business restoration and charitable donations	\$0.5m
7	Portable LNG from Colonial Gas (MA)	\$0.1m
8	Outside legal costs	\$0.6m
9	Total costs	\$27.8m
10	Less base labor costs	(\$2.7m)
11	<b>Total Incremental Costs</b>	<b>\$25.1m</b>

As a general matter, ratemaking in Rhode Island, as in other United States jurisdictions, is typically prospective. Regulated utilities use docketed proceedings before the Public Utilities Commission to present historical data as evidence for what the utility’s costs will be in future years. Once this amount – the revenue requirement - is approved by the Public Utilities Commission in a contested general rate case, utilities may collect the revenue requirement from ratepayers. In general, if actual expenses are less than expected utilities may retain the savings as additional earnings for shareholders. Conversely if expenses are greater than expected then utilities must bear the costs, reducing earnings for shareholders. In other words, after rates are set in a general rate case, the utility cannot change base distribution rates to retroactively charge customers for unexpected higher costs that were incurred in the ordinary course of business. Although in Rhode Island many aspects of utility operations, such as certain safety and reliability infrastructure investments, standard offer service, and energy efficiency, are statutorily exempt from this ratemaking mechanism, the inherent structure of ratemaking is designed to prevent utilities from recovering higher costs from ratepayers retroactively.

In Rhode Island there is a narrow exception to the general rule of prospective ratemaking that allows a utility in the context of an unusually severe storm to seek recovery of extraordinary



expenses.<sup>214</sup> Narragansett Electric may, at its own discretion, seek to recover the incremental costs of the outage through a special filing before the Public Utilities Commission, relying on the exception cited above or some other provision it may believe applicable. Any petition for extraordinary cost recovery would require the approval of the Public Utilities Commission.

Based on the information the Division has gathered to date through its investigation and in coordination with PHMSA, it asserts that multiple factors contributed to the curtailment of the low-pressure system on Aquidneck Island. While one precipitating factor was outside the control of any of the parties involved – the high demand of many customers on the G-System on January 21<sup>st</sup> due to extremely cold weather – the other two factors were within the control of either Enbridge, National Grid LNG or Narragansett Electric.

The two precipitating events were, first, the programming error of Enbridge’s affiliate that caused its flow valve at Weymouth, Massachusetts to malfunction. Had Algonquin programmed its valve in Weymouth correctly, modeling shows that the inlet pressures at Portsmouth would have been sustained at levels that would not have necessitated a curtailment. As the provider of interstate gas transportation, Algonquin had a duty to program its meters and valves correctly to assure safe and reliable service to its customers, including Narragansett Electric. But, in this case, it failed to do so.

Second, the National Grid LNG shutdown of its LNG vaporization facility in Providence contributed to the low-pressure condition when its vaporizers failed. According to PHMSA, National Grid LNG experienced a similar emergency shutdown in November 2018 which they did not adequately investigate or resolve.

As important as these two precipitating factors, however, were the planning and forecasting errors of Narragansett Electric which led the Company to conclude that it did not need to have LNG vaporization capability on Aquidneck Island. If backup LNG vaporization had been in place, Narragansett Electric could have survived the low-pressure condition without an outage by supplementing Aquidneck Island with the vaporized LNG.

The Division has carefully considered the position it would adopt in the event a request for extraordinary cost recovery were filed by Narragansett Electric. While the outage on January 21 would not have happened without the combination of precipitating events occurring, the Division believes that from a ratemaking perspective, Narragansett Electric ratepayers should not bear the

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<sup>214</sup> *Narragansett Electric Co. v. Harsch*, 368 A.2d 1194,1206 (R.I. 1977).

restoration and other post-event incremental costs incurred from the outage. Those costs should be borne by one or more of the gas service providers. In any event, the decision of whether ratepayers should reimburse Narragansett Electric for any of the costs not recovered from the other service providers would be made by the Public Utilities Commission. The Division, however, is not offering any opinion on how responsibility for the resulting costs to Narragansett Electric might be allocated among these parties in any civil litigation.

#### **8.4 Conclusion**

This Report concludes the summary investigation into the events of January 21, 2019. Based on the findings of the Report and pursuant to §39-4-14, the Division will issue a Notice of Probable Violation to Narragansett Electric for the failure to notify of the emergency shut down of the Providence LNG facility. The Division will oppose any potential proposal from Narragansett Electric to recover the \$25 million of costs related to the outage and restoration from ratepayers.

This Report does not end the Division's oversight of Narragansett Electric's gas distribution business. As reflected in its recommendations, the Division has identified areas it believes Narragansett Electric must address in the immediate future. These areas will be a primary focus for ongoing Division regulatory oversight of Narragansett Electric. Although Narragansett Electric has taken steps since January 21, 2019 to address some of the deficiencies identified in this Report, the Division will continue to exert its statutory supervisory authority under Title 39 of Rhode Island General Laws to address the recommendations identified in this report to maximally reduce the possibility of a similar event recurring to Rhode Island gas customers.

Beyond the events of January 21, 2019 themselves, the lessons of the Aquidneck Island gas service interruption should inform discussion among state regulators, Narragansett Electric and other stakeholders to consider the long-term development of the gas distribution business.