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Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2016–2017

REPORT TO THE
NOVA SCOTIA UTILITY AND REVIEW BOARD

Prepared by Bates White, LLC

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Abbreviations

AA	Actual Adjustment
AF	Availability Factor
AGT	Algonquin Gas Transmission
ASTM	American Society for Testing and Materials
BA	Balancing Adjustment
BCF	Base Cost of Fuel
CAD	Canadian dollar
COMFIT	Community Feed in Tariff
CO_2	carbon dioxide
COO	chief operating officer
CRF	compressor rear frame
CROC	Credit Risk Oversight Committee
CT	combustion turbine
DAFOR	de-rated adjusted forced outage rate
DR	demand response
DSM	Demand-Side Management
ECC	Energy Control Centre
EE	energy efficiency
EFOR	Equivalent Forced Outage Rate
EIA	US Energy Information Administration
EPIA	Electricity Plan Implementation (2015) Act
ERM	Enterprise Risk Management group (Emera)
ERMC	Enterprise Risk Management Committee (Emera)
ESP	Emission Shadow Price
ETRM	Energy Trading and Risk Management software
FAM	Fuel Adjustment Mechanism
FERM	Fuels Energy and Risk Management
FOM	first of the month
F&PP	Fuel and Purchased Power
FST	Fuel Strategy Table
GAM	Generation Asset Management
HFO	heavy fuel oil
Hg	mercury
IPP	independent power producer
IRP	Integrated Resource Plan
ISDA	International Swaps and Derivatives
IT	information technology
LFO	light fuel oil
LNG	liquefied natural gas
LRT	Load Retention Tariff
LSH	low-sulphur, high Btu
McF	thousand cubic feet
M&NE	Maritimes and Northeast Pipeline
MT	metric tonne
MTM	mark-to-market
MVAR	mega volt ampere reactive power
NAESB	North American Energy Standards Board
NBEM	New Brunswick Power Energy Marketing
NBP	New Brunswick Power
NERC	North American Electric Reliability Corporation
NO_x	nitrous oxide

NPCC	Northeast Power Coordinating Council
NSPI	Nova Scotia Power, Inc.
NSPSO	Nova Scotia Power System Operator
NSR	Net System Requirement
NSUARB	Nova Scotia Utility and Review Board
OEM	original equipment manufacturer
O&M	operating and maintenance
OM&G	operating, maintenance, and general
OTC	over the counter
PAC	power-activated carbon
PH	Port Hawkesbury
PHB	Port Hawkesbury Biomass
PHP	Port Hawkesbury Paper
PI	Process Information
PNGTS	Portland Natural Gas Transmission System
POA	FAM Plan of Administration
PPA	power purchase agreement
PRB	Powder River Basin
PXP	Portland Xpress Project
REC	Renewable Energy Certificate
RECSI	Regional Electricity Cooperation and Strategic Infrastructure
RFP	request for proposal
ROA	Record of Approval
RSP	Rate Stability Period
SAE	Statistically Adjusted End-Use
SO_2	sulphur dioxide
SOEP	Sable Offshore Energy Project
SWG	FAM Small Working Group
TGP	Tennessee Gas Pipeline
Tidal FIT	developmental tidal feed in tariff
TSR	total system requirement
USD	United States dollar
VaR	value at risk
VOM	variable operation and maintenance costs
WACC	weighted average cost of capital
WTUI	Western Turbine Users Inc.

I. Introduction and Background

Bates White Economic Consulting ("Bates White")[1] appreciates the opportunity[2] to serve the Nova Scotia Utility and Review Board (NSUARB, or "the Board") as its independent consultant tasked with providing an audit of Nova Scotia Power, Inc.'s (NSPI's) Fuel Adjustment Mechanism (FAM) for the period January 1, 2016, through December 31, 2017 ("Audit Period"). This report provides the results of our audit ("Audit Report").

I.A. Brief Background on Nova Scotia Power, Inc.

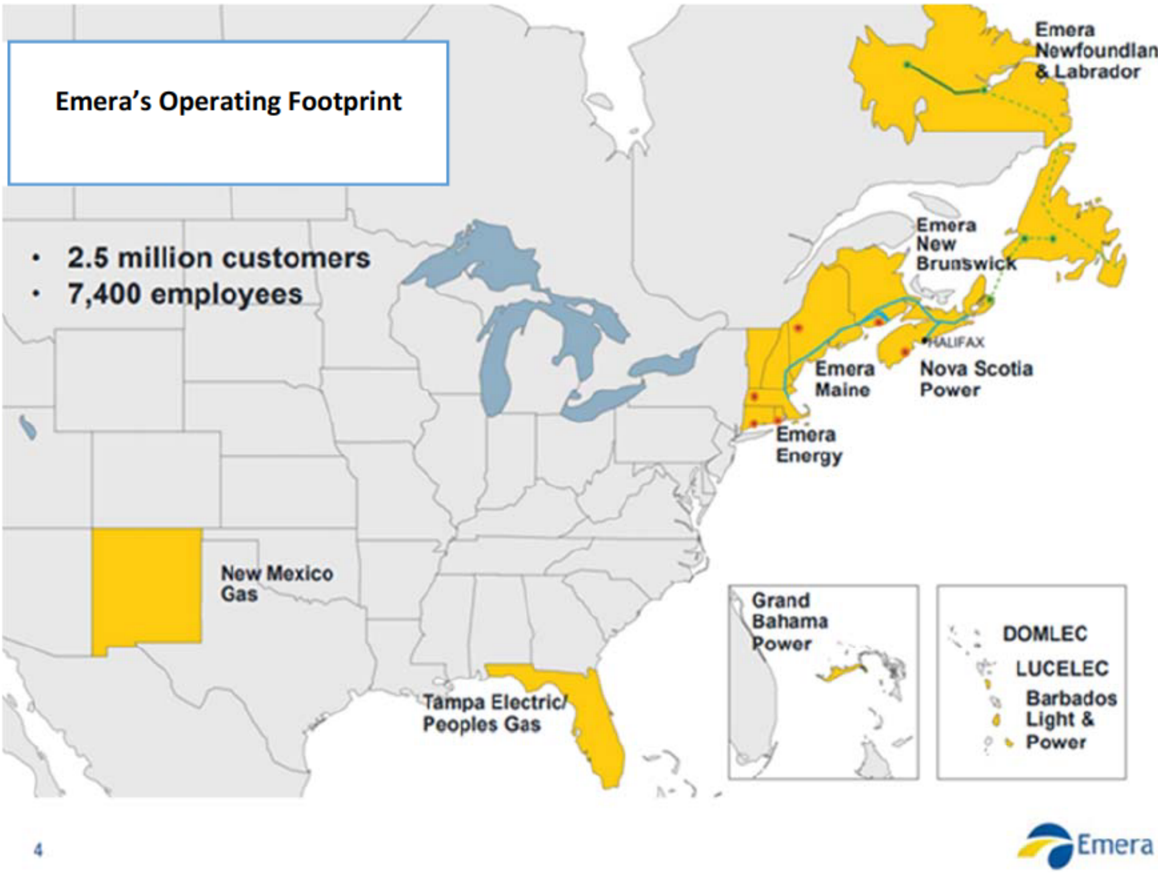
NSPI, operating as a privatized company since 1992, provides 95% of the generation, transmission, and distribution of electricity in Nova Scotia. NSPI serves approximately 500,000 residential, commercial, and industrial customers. NSPI's rate base is approximately $4.3 billion, which consists in part of approximately 2,450 MW of generating assets and 32,000 kilometres of transmission and distribution lines.

NSPI is a wholly owned subsidiary of Emera Inc. ("Emera"), a diversified energy and services company with approximately 2.5 million customers, 7,400 employees, and $29 billion in assets. Figure I-1 below shows Emera's operating footprint.

[1] Bates White is an economic consulting firm offering services to law firms, Fortune 500 companies, and government agencies. Founded in 1999 and headquartered in Washington, DC, we have been recognized by *The Washington Post* as a Top Workplace, named a Top 50 Consulting Firm by Vault, and cited as a Top 21 Economics Firm by Global Competition Review.

[2] In a July 25, 2017, letter to NSPI in docket M08195, the Board announced our retention for this role.

Figure I-1. Emera's Footprint



I.B. The Fuel Adjustment Mechanism

The FAM is the cost recovery mechanism by which NSPI recovers the cost of fuel and purchased power from its customers. According to NSPI, fuel is its largest expense in providing electricity to customers, representing approximately 40 percent of its total costs.[3] In 2016, FAM costs totaled $490.2 million; in 2017, that number fell to $476.9 million. These FAM costs are passed through directly to customers.[4]

The FAM is intended to allow NSPI to recover the exact amount of FAM costs from ratepayers without the need for a general rate case. To do so, the FAM rate has three components: (1) the Base Cost of Fuel (BCF); (2) the Actual Adjustment (AA); and (3) the Balancing Adjustment (BA). The BCF is the test year forecast of fuel costs that are incorporated into customer rates by calculating the fuel cost

[3] NSPI, "2016 FAM Base Cost of Fuel Application," August 10, 2015, page 6, lines 17–19.

[4] 2016 FAM BCF Application, page 6, lines 19 to 20.

component of customer electricity rates.[5] Historically, the BCF is reset every two years or, alternatively, in the course of any general rate application.

Since the BCF is based on forecasts, there will always be differences between the FAM costs recovered via the BCF and the actual FAM costs that NSPI incurs. Such differences are accrued by NSPI in a regulatory asset account (if NSPI under-recovers its actual fuel costs) or a regulatory liability account (if NSPI over-recovers its actual fuel costs). These accounts earn interest at NSPI's effective weighted average cost of capital (WACC).[6] To ensure NSPI recovers only its actual FAM costs exactly, a true-up is necessary. To true up the costs, recoveries from or refunds to ratepayers any excess via two adjustments—the AA and BA—which change each year.[7] As explained by NSPI:

> The AA represents the difference in the current year between the amount actually spent on fuel and the fuel-related revenue actually recovered from customers. At year end, the under- or over-recovered amount (plus the applicable interest) will be the total FAM deferral amount for that year. For purposes of establishing customer rates to recover or refund the FAM deferral account, NS Power files an application which includes 10 months of actual results (January to October) and two months of forecast data (November and December). This AA/BA application is filed in November of each year for rates effective January 1 of the following year.
>
> This total deferral amount is divided by the upcoming year's sales forecast in order to determine the AA amount.
>
> …
>
> The BA represents the difference (if any) in the prior year between the actual fuel costs and the fuel-related revenue recovered from customers…[T]he FAM AA calculation uses ten months of actual data, and two months of forecast data (relating to both fuel expense and load). As actual sales and fuel costs vary from forecast, a balancing adjustment is required.
>
> The BA comprises any previously deferred FAM amounts and the residual amount of the AA related to the previous year not fully refunded or recovered by the AA. Similar to the AA, the BA rate is established using the cumulative under- or over-recovery divided by forecasted sales for the period. Any residual BA at the end of a year is applied to the

5 NSUARB, "Decision," In the Matter of a hearing into Nova Scotia Power Incorporated's Base Cost of Fuel Reset and Fuel Forecast Standardized Filing for 2011 Fuel Adjustment Mechanism, NSUARB-P-887(2), November 18, 2010, page 6.

6 2016 FAM BCF Application, page 10 line 23 to page 11 line 7.

7 2016 FAM BCF Application, page 8, lines 11 to 17.

> following year and is used in the determination of future BA rates. In this way, only actual costs are recovered from customers.[8]

Again, in a typical FAM rate cycle, the BCF would be set for a two-year period, while the AA and BA adjustments would be reset annually to make sure that FAM recovery exactly equaled FAM expenditures over that two-year period. However, on December 18, 2015, the Province enacted the Electricity Plan Implementation (2015) Act (EPIA), which required NSPI to "apply to the Board for approval of a Fuel Stability Plan that sets the amount customers will pay for fuel for…2017, 2018, and 2019," which is referred to as the "Rate Stability Period."[9] On March 7, 2016, NSPI filed its Fuel Stability Plan with the Board, which specified an average annual increase in FAM customer rates of 1.3% in each year of the Rate Stability Period,[10] which the Board accepted on July 19, 2016.[11] The Board noted that, while the AA and BA adjustment process would not occur annually during the Rate Stability Period, NSPI's "[a]ctual fuel costs will be tracked during the duration of the Fuel Stability Plan and trued up at the end of the Rate Stability Period, which ends December 31, 2019."[12]

The specific costs allowed to be recovered through the FAM include (1) natural gas;[13] (2) solid fuel;[14] (3) heavy fuel oil (HFO);[15] (4) diesel oil;[16] (5) light starter oil;[17] (6) fuel—additives;[18] (7) fuel—

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8 2016 FAM BCF Application, page 11 line 11 to page 12 line 6.

9 NSUARB, "Decision," In the Matter of a hearing into Nova Scotia Power Incorporated's 2017–2019 Fuel Stability Plan and Base Cost of Fuel Reset under the Fuel Adjustment Mechanism as required under the Electricity Plan Implementation (2015) Act, M07348, July 19, 2016 [hereinafter "2016 Board BCF Decision"], paragraph 3.

10 2016 Board BCF Decision, paragraph 5.

11 2016 Board BCF Decision, paragraph 60.

12 2016 Board BCF Decision, paragraph 5.

13 This includes (1) natural gas consumed; (2) financial instruments used for hedging (including gains, losses, fees and interest charges); (3) pipeline reservation fees, tolls, penalties (such as imbalance charges); (4) pipeline losses; and (5) natural gas storage fees. See section 3.2.1 of the FAM Plan of Administration (POA).

14 This includes (1) inventoried costs, such as commodity costs (coal, petroleum coke), financial instruments used for hedging (including gains, losses, fees and interest charges), third-party quality testing and sampling, and transportation costs (e.g., by rail, barge, vessel, truck etc.), including loading, unloading, dispatch, demurrage, port fees, draft surveys, and marine service fees; (2) costs directly applied, including third-party handling, transportation (e.g., movement between Long-Term Dead Storage/Bear head and plants) and maintenance related to coal piles, storage fees (e.g., lease, handling fees, facility fees), environmental compliance fees (e.g., provincial air emissions fees), rail car costs (e.g., lease, repair, maintenance), and international pier operating and maintenance costs; (3) costs expensed through the Plant Fuel Handling Adjustment (i.e., expenses incurred up until the point of the reclaim hopper), including NSPI labour and associated costs for equipment operators, mechanics, supervisors related to fuel handling and lab techs related to testing, costs associated with measurement of inventory (e.g., surveys density testing), non-capital materials for fuel handling (e.g., tools, replacement parts for machines), repair costs for fuel handling equipment and infrastructure, heavy equipment operating costs for fuel handling (e.g., rental and fuel), and Point Tupper Marine Terminal operating and maintenance costs. See section 3.2.2 of the FAM POA.

15 This includes (1) HFO/bunker fuel consumed; (2) financial instruments used for hedging (including gains, losses, fees and interest charges); (3) quality testing and inventory measurement costs; (4) standby emergency response services; (5) third-party supervision of unloading; and (6) transportation costs (e.g., rail, barge, vessel, truck, etc.) including loading, unloading, dispatch, demurrage, port fees, draft surveys, and marine service fees. See section 3.2.3 of the FAM POA.

16 This includes (1) diesel commodity consumed, (2) transportation costs, and (3) quality testing and inventory measurement costs. See section 3.2.4 of the FAM POA.

17 This includes (1) light fuel oil (LFO) commodity consumed, (2) transportation cost, and (3) quality testing and inventory measurement costs. See section 3.2.5 of the FAM POA.

18 This includes additives—Ultramag, FireShield, etc—and transportation costs. See section 3.2.6 of the FAM POA.

limestone;[19] (8) purchased power;[20] (9) fuel biomass;[21] (10) fuel—mercury sorbent;[22] (11) grid sales revenue;[23] (12) natural gas revenue;[24] (13) miscellaneous revenue and recoveries;[25] (14) foreign exchange;[26] (15) limited-duration fuel testing;[27] and (16) below-the-line costs.[28]

I.C. The FAM Audit Scope

The FAM audit is provided for in the FAM Plan of Administration. Specifically, the FAM POA states:

> The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently.[29]

The Board has previously and clearly defined the prudence standard to be applied in the FAM Audit:

> The standard for determining prudency of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, 'prudence is that standard of care which a reasonable person would be expected to exercise under the same

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[19] This includes (1) limestone and related transportation; (2) limestone ash hauling and equipment rentals; (3) limestone royalties; and (4) water royalties. See section 3.2.7 of the FAM POA.

[20] This includes (1) independent power producer (IPP) purchases (e.g., Wholesale Market Non-Dispatchable Spill Tariff) and IPP and Community Feed in Tariff (COMFIT) production bonuses and penalties; (2) COMFIT purchases; (3) developmental tidal feed in tariff ("Tidal FIT") purchases; (4) import power purchases and associated fees (e.g., transmission tariffs and losses); (5) renewable energy credits; and (6) financial instruments used for hedging (including gains, losses, fees and interest charges). See section 3.2.8 of the FAM POA.

[21] This includes (1) biomass commodity consumed; (2) maintenance and operating expenses for fuel handling (allocation between operating, maintenance, and general (OM&G) and FAM); (3) third-party quality testing and inventory management costs (e.g., surveys, density testing, sampling); (4) storage fees (e.g., lease, handling fees, facility fees); (5) environmental compliance including Silviculture Fees and harvest audits; and (6) transportation costs (e.g., by barge, truck etc.). See section 3.2.9 of the FAM POA.

[22] This includes (1) additives—power activated carbon (PAC) and calcium chloride; (2) transportation costs; and (3) costs relating to an Hg (mercury) diversion program that the Minister of Environment approved under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended. See section 3.2.10 of the FAM POA.

[23] This includes any revenue from power exports net of any transmission tariffs and losses; this includes renewable energy credits arising out of the sale of renewable energy in the New England market. See section 3.2.11 of the FAM POA.

[24] This includes any revenue from the resale of natural gas. See section 3.2.12 of the FAM POA.

[25] This includes revenues from joint partnerships in wind farms, other fuel-related miscellaneous revenues, steam sales to Port Hawkesbury Paper, and steam sales at the Trenton generating station. See section 3.2.13 of the FAM POA.

[26] This includes adjustments to record expenses or revenues denominated in foreign currencies and includes the gain or loss on currency hedges entered into for the purpose of fuel procurement. See section 3.2.14 of the FAM POA.

[27] This includes fuel testing costs (including solid fuel, liquid, and additives such as PAC) and consists of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third-party testing and analysis), only to the extent incurred as part of limited duration test burns occasionally made by NSPI, limited to non-capital costs. See section 3.2.15 of the FAM POA.

[28] This includes spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff and fuel costs incurred in providing service under the Wholesale Market Backup/Top-Up Service Tariff, less revenue received under the Wholesale Market Backup/Top-Up Service Tariff net of non-fuel items. See section 3.2.16 of the FAM POA.

[29] FAM POA, section 5.0.

> circumstances encountered by utility management at the time decisions had to be made…Hindsight is not applied in assessing prudence…A utility's decision is prudent if it was within the range of decisions reasonable persons might have made…The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.[30]

The POA specifies that the Board will use "a qualified independent firm [to] conduct the audit," which will "address the financial and management/performance aspects of NSPI's fuel procurement and recovery under the FAM."[31] The audit will review "the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period."[32] The POA explains the objectives and scope of the audit as follows:

> The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power's procurement as described in the NS Power Fuel Manual.
>
> The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power's conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):
>
> - Fuel and purchased power costs
> - Review of overall operational availability and capacity factor for the generating fleet
> - Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
> - Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
> - Review all Fuel and Purchased Power contracts executed by NS Power for the period under review for prudency and for compliance with the Fuel Manual

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30 NSUARB, "Decision," In the Matter of a hearing into Nova Scotia Power Incorporated's Fuel Adjustment Mechanism Audit for the years 2014 and 2015, M07611, December 21, 2016, paragraph 13, citing 2005 NSUARB 27, paragraph 84.

31 FAM POA, section 5.0.

32 FAM POA, section 5.0.

- Review of NS Power's use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments[33]

In addition to those topics specifically identified in the FAM POA, the Board also tasked us with additional items to cover in our audit. Those topics include issues related to Port Hawkesbury Paper's (PHP) Load Retention Tariff (LRT) and the co-located biomass generating plant, certain engine refurbishment costs associated with an LM6000 engine at Tufts Cove, and NSPI's revised approach to internal auditing. We address these issues in our final chapter.

I.D. Our Methodology and Process

Bates White's approach to the audit was to compile a record of information obtained from NSPI through formal data requests, in-person interviews, in-person demonstrations, in-person sensitive document review, site visits, and conference calls. We issued formal data requests, reviewed hundreds of contracts for FAM-related products and services, and conducted numerous conference calls and interviews with key personnel at NSPI, including management and operations personnel that are responsible for fuel and power procurement, sales, and supply management. We also conducted several site visits, including multiple visits to (1) NSPI's headquarters in Halifax; (2) the Energy Control Centre; (3) the Tufts Cove generating station in Dartmouth; (4) the Trenton generating station in Trenton; (5) the Port Hawkesbury biomass facility in Port Hawkesbury; (6) the Point Tupper Marine Terminal in Point Tupper; and (7) the Lingan generating station in Lingan. From the record of evidence we compiled, we also conducted independent quantitative analysis using NSPI-provided data. Our report's findings, conclusions, and recommendations are based on that record of information.

Our audit had a specific, defined scope of work. We focused on NSPI's practices, procedures, and processes for FAM-related items. We did not audit NSPI's operations outside of its fuel and power procurement processes, nor its compliance with reliability standards. Further, while we sampled hundreds of transactions for FAM-recoverable products and services for prudence, we did not review every FAM-recoverable transaction the NSPI made over the Audit Period.

We note here that in conducting the FAM audit for the first time, we found NSPI cooperative and responsive throughout the audit process. NSPI accommodated our requests to interview dozens of specific NSPI employees; to review NSPI's models and software tools; and to receive countless contracts, reports, invoices, and other forms of supporting documentation requested throughout the audit process. NSPI staffed the audit with sufficient resources to provide a consistent, logical interface with our audit team and to provide information in a reasonable timeframe. NSPI also used a secure document sharing platform —

33 FAM POA, section 5.0.

SharePoint—to allow for efficient sharing of documents that served as a reliable record of documents provided to date throughout the process.

I.E. Structure of this Report

Our report proceeds as follows. We have 13 substantive chapters, each addressing a different aspect of our scope of work—and NSPI's FAM-related activities:

- Chapter II—Organization, Staffing, and Controls
- Chapter III—Planning and Fuel Supply Forecasting
- Chapter IV—Solid Fuel Procurement
- Chapter V—Solid Fuel Supply Management
- Chapter VI—Natural Gas Supply Planning
- Chapter VII—Natural Gas Procurement
- Chapter VIII—Oil Procurement and Management
- Chapter IX—Power Plant Performance
- Chapter X—Economic Commitment and Dispatch
- Chapter XI—Power Purchases and Sales
- Chapter XII—Hedging
- Chapter XIII—FAM Accounting
- Chapter XIV—Board-Specific Issues (PHP, LM6000 refurbishment, and internal auditing)

We note that Chapter XIII (FAM Accounting) was primarily authored by Horne, LLP, with Bates White providing review. We also note that all currency figures in this report are Canadian dollars (CAD), unless otherwise noted.

Each chapter has the same structure. Each begins with a **Background** section, which provides contextual information useful for understanding the chapter. Next is the **Findings** section, which contains our factual records, evidence, and analysis. This is always the longest of the sections, as it serves as the factual basis for the next two sections. The next section is the **Conclusions** section, which includes our distilled deductions and judgments on NSPI's FAM-related activities during the Audit Period. This section is particularly important for readers to review, as it provides our view of what NSPI is doing well and what can be done better. Last is the **Recommendations** section, which contains our action items for NSPI to address to improve outcomes for FAM customers.[34]

[34] It is our understanding that the precise timeline for the FAM hearing is not yet finalized. For our part, we would note to the Board that some of our recommendations are time sensitive and would be advantaged by an earlier hearing process.

II. Organization, Staffing, and Controls

II.A. Background

This chapter addresses NSPI's organization, staffing, and controls—including risk management—related to fuel and purchased power.

II.B. Findings

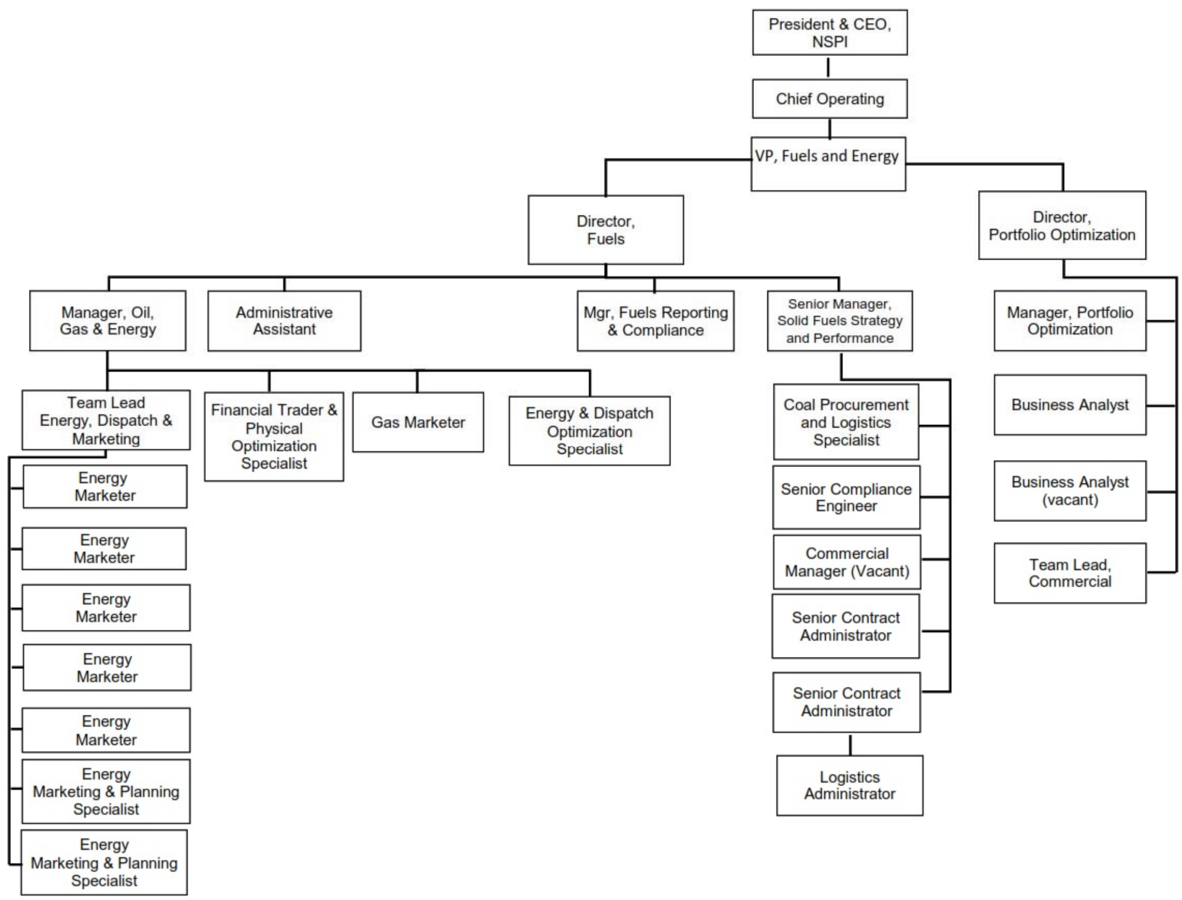
II.B.1. Organization

NSPI's fuel and power purchasing and management is the responsibility of NSPI's Fuels Energy and Risk Management (FERM) group. FERM buys solid fuel, natural gas, fuel oils, biomass fuel, and other fuels, additives, and related services for the production of power at NSPI's power plants. FERM also buys and sells power and develops commitment and dispatch schedules for NSPI's generation resources. FERM is the primary entity whose decision making impacts FAM costs.

In executing its responsibilities, FERM interacts with many other areas of NSPI's organization, many of which have some impact on FAM costs. FERM coordinates on a variety of matters with NSPI's system operator—the Nova Scotia Power System Operator (NSPSO)—including day-ahead planning and real-time operations of the generation fleet and outages. NSPI's Portfolio Optimization group is primarily responsible for the fuel and purchased power forecasts that drive NSPI's purchasing decisions. NSPI's Generation Asset Management team centrally manages NSPI's generation fleet performance monitoring and management, while also providing FERM with the operating characteristics of each of NSPI's generation units. Plant personnel at each of NSPI's generating facilities also play a key role in operating and maintaining NSPI's assets and coordinating with FERM regularly, including during daily day-ahead planning calls. NSPI's Fuels Finance team provides back office support to FERM. Throughout the remainder of this report, the roles and performance of these teams are discussed in more detail.

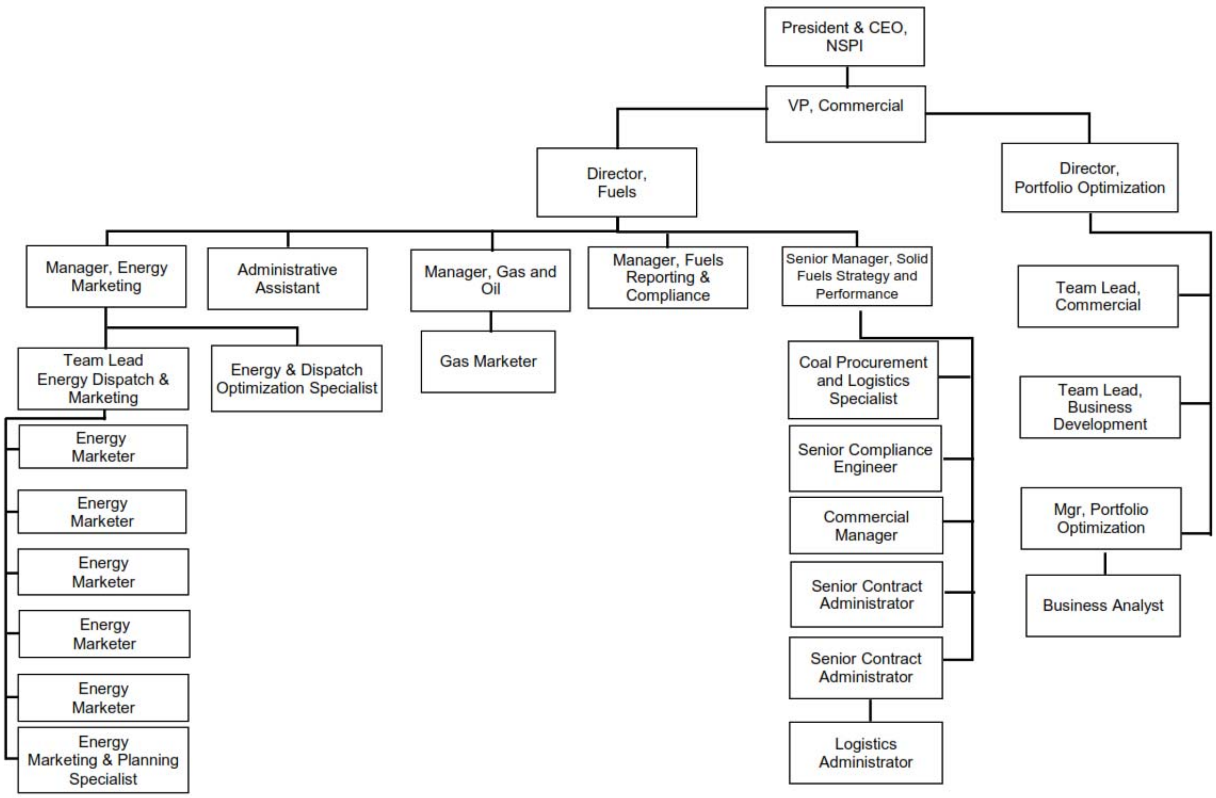
Figure II-1 below shows NSPI's organizational structure as it relates to fuel and power purchasing. Note that, in 2016, NSPI's Vice President of FERM reported to the NSPI Chief Operating Officer (COO). Also note that NSPI's FERM group featured two main teams: Portfolio Optimization and Fuels. This structure, which provided a reasonable structure for NSPI's fuel and power purchasing, was largely similar to that in place in 2014 and 2015.

Figure II-1. NSPI's Fuels-Related 2016 Organizational Chart



NSPI introduced some changes to its organizational structure for 2017. As is shown in Figure II-2, NSPI's Vice President of FERM was retitled "Vice President, Commercial," and, instead of reporting to NSPI's COO, that individual now reports directly to NSPI's President and Chief Executive Officer. Moreover, while the Portfolio Optimization and Fuels groups remained, NSPI also introduced some changes to the Fuels group, including removing gas marketing from the power marketing structure and making it a standalone subgroup. These changes appear reasonable and may benefit NSPI's functionality, especially if NSPI becomes more reliant on natural gas purchases.

Figure II-2. NSPI's Fuels-Related 2017 Organizational Chart[1]



We reviewed the job descriptions of most of the positions in Figures II-1 and II-2 above; in all cases, the key accountabilities of each role were clearly defined. This is an important feature to ensure that each employee understands his or her role in the fuel and purchased power processes, and for management to use in tracking and benchmarking employee performance. We note, too, that the job descriptions for senior positions, such as the Director, were particularly detailed. As we note below, this will assist NSPI in its succession planning efforts.

II.B.2. Staffing

II.B.2.a. FERM Employees

FERM is well staffed with experienced personnel, particularly in key leadership positions across the department. We observed through a series of interviews, discussions by phone, and reviews of individual résumés that FERM personnel were knowledgeable about their specific roles and how their roles fit within the processes and goals of the larger group. Moreover, FERM personnel's background varied: in some cases, FERM personnel have had substantial tenures with NSPI in the same or similar role, while others have shorter tenures and came to NSPI as external hires. In both cases, we observed the FERM

1 NSPI 2017 FAM Annual Report, A-1.

employees to be competent and knowledgeable. We would add our own note here that the external hires who are currently FERM employees bring strong backgrounds in fuel and power procurement, including strong market experience gained in other jurisdictions. We think this combination of long-tenured FERM employees and newer hires with strong external credentials can provide FAM customers with benefits. A key to drawing those benefits out are other issues related to staffing, such as training, and risk management and controls, both of which we cover below.

II.B.2.b. Performance Management

NSPI uses a standardized, company-wide performance management program, referred to as My Annual Performance Plan. As has become standard human resources practice, employees are required to be proactive; in consultation with their direct supervisor, NSPI employees outline key accountabilities for their position for the year as well as the goals associated with their role for the year—note, again, that well-defined job descriptions and accountabilities (explained above) feed directly into the performance management process. Employees meet with their supervisor at three regular intervals during the year. First, they meet at the beginning of year to set accountabilities and goals for the year; next, they meet for a mid-year review to discuss progress on accountabilities and goals and to make adjustments where required; last, they meet at year's end to assess whether all accountabilities and goals were completed, and to what degree the overall performance was achieved.

The performance management program meetings look at both the employee's performance during the previous period and long-term career goals. The employee and supervisor discuss training and additional resources needed to help the employee grow and attain his or her career goals and objectives. Year-end performance ratings are calibrated through a facilitated discussion among managers or leadership teams to create alignment within the organization on the performance ratings and feedback to be given to direct reports. The process helps ensure all employees are evaluated on the same criteria, no matter to whom they report. The calibration process provides leaders with an opportunity to highlight the strengths, accomplishments, and development needs of their team members. In addition, it provides supervisors the chance to gain insight into the perspectives of other supervisors regarding performance of their team members. Following the calibration session, NSPI executive leadership approves all year-end ratings; employees then receive their year-end rating along with feedback from the calibration session. As we explain below, NSPI's performance management process appropriately ties directly to both employees' incentive-based compensation and training, as well as to NSPI's succession planning process.

II.B.2.c. Training

NSPI requires FERM employees to take annual training across a variety of topics, including: (1) the Emera Code of Conduct; (2) the NSPI Fuel Manual; (3) the NSPI Affiliate Code of Conduct; (4) the Emera Credit Policy; and (5) NSPI's Fuel Procurement Risk Management Policy and Procedures. New employees are required to take these training sessions upon being hired, and like every other employee, take them again annually. The Manager of Reporting and Compliance coordinates and tracks corporate policy training for FERM employees.

FERM employees also receive more specialized training depending on their role. For example, employees involved in the preparation of the FAM receive training on the processes and requirements for the filings with the Board. Employees also attend training sessions identified through their performance management process as part of their short-term and long-term development plans.

We reviewed materials related to several training sessions. We found that the materials themselves were sufficiently detailed, contained very clear definitions and guidelines, and were easily understandable. In the training session on the Affiliate Code of Conduct, for example, we observed clear and accurate definitions of key terms, appropriate explanations of and guidance on "grey area" issues, and point-of-contact information for NSPI employees who have questions about the Affiliate Code of Conduct. Another example is the training on Credit and Market Risk Concepts and Emera Policy, which defines risk parameters, explains the applicable risk policies in place, and has clear, visual demonstrations of NSPI's systems (e.g., Allegro) as they relate to credit and market risk.

II.B.2.d. Incentive-Based Compensation

NSPI offers two incentive-based compensation programs for NSPI's FERM employees: the Commercial Incentive Program and the Short-Term Incentive Program. Both incentive programs are driven by both individual employee performance and the performance of the broader organization—whether it be FERM or NSPI-wide. This is a reasonable structure that creates incentives for individual employees to perform well, while creating a broader incentive for all employees to strive to meet corporate and departmental goals.

The first incentive program is NSPI's Commercial Incentive Program. It is designed to reward FERM employees based on the success of FERM and the employee's performance. The overall incentive target is expressed as a percentage of the employee's base salary. These incentive range are targeted at [redacted], depending on the direct relation to the trading desk. The determinants of FERM's success are a series of reasonable performance incentives, such as (1) realizing a lower actual fuel cost than forecasted, (2) achieving hedging targets under the Fuel Hedging Plan, and (3) demonstrating operating and maintenance cost savings in the fleet. We reviewed NSPI's results under this new plan for 2017 and agreed with its determinations regarding which targets were met and which were not. One additional item worth noting here was monetization of available and economic surplus generation, which would reward FERM and its employees for selling excess and economic power exports showing benefits of [redacted] or greater. While we agree this is a reasonable metric for inclusion in the Commercial Incentive Program, we have a recommendation to clarify that the benefits are realized benefits, not forecasted benefits—as we explain in the Purchased Power and Sales chapter, NSPI's power export decisions often involve estimates of revenues and costs, which means realized benefits can differ from forecasted benefits.

The second incentive program is NSPI's Short-Term Incentive plan, which is driven by NSPI-wide performance as well as the individual's performance. Annual performance objectives are established for each individual employee and for NSPI's Power's Corporate Scorecard. Every employee has an individual target incentive based upon his or her level within the organization. At the end of the calendar year, the incentive calculation is based on both individual and company performance. Payments under the Short-Term Incentive plan are a smaller portion of a FERM employee's potential incentive payment than payments under the Commercial Incentive Program—a reasonable approach that recognizes that an employee has more impact over FERM's performance than NSPI as a company.

Both incentive programs are appropriately linked directly to NSPI's performance management program. Specifically, in both incentive programs, which we explain below, FERM employees are assessed a "multiplier" that is used to calculate the size of the employee's bonuses, if any, under these two programs. The multiplier is determined by the employee's year-end performance rating under the performance management program. For example, employees rated as "meeting expectations" receive a multiplier of 1; employees exceeding expectations can earn a multiplier as high as 1.5, and employees failing to meet expectations receive multipliers below 1, and potentially zero.

II.B.2.e. Succession Planning

In response to a recommendation of the previous fuel auditor, which we address later in this chapter, NSPI developed a succession plan for senior leadership in FERM with the assistance of NSPI's human resources department. The succession plan—which we reviewed in person during a site visit—spans the FERM group and is planned for implementation in other departments at NSPI. FERM senior leadership worked to define the core technical and leadership competencies of each role—which are consistent with the job descriptions we note above. The succession plan includes an assessment of the criticality of each FERM role, which allows management to better use the succession plan as a planning tool.

As part of the succession plan, supervisors meet with FERM to discuss their future career goals and aspirations, including identification of roles that employee may seek in the future. This process enables NS Power to assess potential successors against the skills and competencies required for the position of interest. Where development gaps exist, an action plan is created to close the gaps. We observed this information first hand and noted clear and understandable guidelines and paths forward for FERM employees.

NSPI indicated that the outcome of succession planning creates a way to assess current capabilities within the department, identifies retention risks within the department, and links the succession development plan to NSPI's detailing both short- and long-term development plans. Our assessment is that this plan will help achieve these goals.

II.B.3. Controls

II.B.3.a. Fuel Manual

NSPI's Fuel Manual[2] is a particularly useful tool for NSPI to hold its employees accountable to its policies and for the Board to hold NSPI accountable for its decisions related to fuel and power

2 Entering the Audit Period, the then-effective Fuel Manual was Version 8. Over the Audit Period, NSPI revised the Fuel

purchasing. We found the Fuel Manual to contain a substantial amount of information about the goals and guidelines applicable to NSPI and FERM employees that should serve as guides on a day-to-day basis. It contains appropriate statements of policy—e.g., [redacted]"[3]—clear references to applicable guidelines—e.g., [redacted]"[4]—and clear statements of goals—e.g., [redacted]."[5] Statements like these codified in the Fuel Manual are important, as they serve to hold NSPI accountable for its actions during the Audit Period and to create a set of best practices that NSPI should follow going forward, even if a particular practice receives little attention by the Board or an auditor for some period of time.

The Fuel Manual also contains the detailed processes and guidelines NSPI must follow in planning and procuring fuel and purchased power across all fuels. This, again, creates accountability; helps NSPI employees do their jobs effectively; and creates a touchstone for NSPI, the Board, stakeholders, and ratepayers to assess NSPI's performance. Moreover, the Fuel Manual contains the key areas of risk management that dictate how NSPI is to address the inherent risks in transacting for a fuel and purchased power portfolio the size of NSPI's.

It is not our intent to address each area of the Fuel Manual here; we do so elsewhere throughout this report and make any recommendations regarding the Fuel Manual in the context of the topic area addressed. Here, we find only that the Fuel Manual is a crucial control in place during the Audit Period. Moreover, below, we address improvements made to the Fuel Manual and its management, particularly in response to recommendations from the previous fuel auditor.

II.B.3.b. Risk Management

NSPI's fuel and power purchasing activities inherently expose it to a variety of risks. Prudent utilities manage those risks, such as counterparty, credit, country, market, regulatory, and currency risks, through well-defined processes, documentation, and organizational structures. NSPI appropriately uses a variety of risk management measures that are industry standard and that should be effective in managing these common utility risks.

II.B.3.b.i. Organization

NSPI has a front, middle, and back office. NSPI's front office engages in commercial transactions, buying and selling fuels and power on behalf of NSPI customers; the middle office serves as a control on

Manual twice; the currently effective version is Version 10.

3 Fuel Manual Revision 10, section 2.1.

4 Fuel Manual Revision 10, section 2.1.

5 Fuel Manual Revision 10, section 2.2.

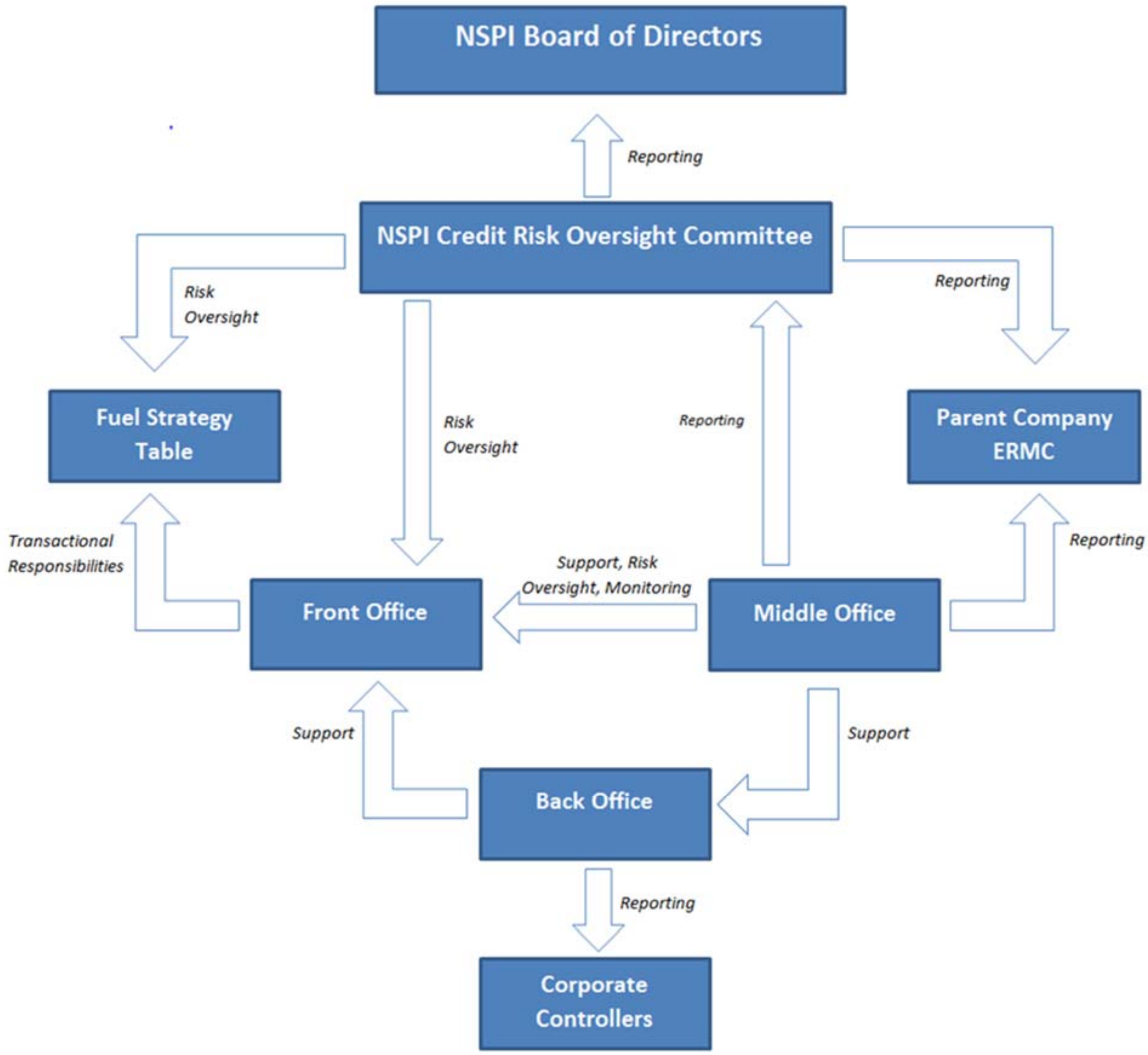
the front office, policing its activities to ensure data integrity through deal validation, analyzing and monitoring market and credit risks, validating price curves, and reporting risk data to management; the back office serves as an additional control through maintenance of the balance sheet, (e.g., accounts receivable, accounts payable), settlements, and financial reporting.

FERM undertakes NSPI's front office activities, while back office responsibilities fall to the Fuels Finance team. The middle office role is handled at the Emera level; Emera's Enterprise Risk Management (ERM) group acts as middle office for NSPI and is responsible for ensuring that, on a day-to-day basis, the credit and market risk management program is being followed. Responsibility for setting Emera-wide risk management policies lies with the Emera Enterprise Risk Management Committee (ERMC), which is made up of leaders from across the Emera group of companies, including the President and CEO of NSPI. The ERMC defines Emera's approach to certain risks, including credit, market, and trading risk. It is up to all Emera companies—including NSPI—to define the specifics of their own risk management procedures to be followed, but the ERMC is responsible for ensuring that appropriate risk management procedures are in place for Emera and each of its businesses, including NSPI, and that these procedures are within a consistent framework. ERM, as NSPI's middle office, reports to the ERMC.

At NSPI, fuel risk management begins with the NSPI Board of Directors, which discusses and approves policies related to NSPI's risk management program and risk assessment. NSPI's overall risk management is governed by the Credit Risk Oversight Committee (CROC). This responsibility includes the overall direction, implementation, structure, coordination, conduct, control, and oversight of the risk management program.[6] Another key player in NSPI's risk management organization is the Fuels Strategy Table (FST), which governs NSPI's fuel procurement and hedging activities. We discuss these roles in more specificity below. NSPI's risk management organizational chart is shown in Figure II-3 below.

[6] NSPI Fuel Procurement Risk Management Policy and Procedures, May 30, 2016 ("NSPI Risk Manual"), section 2.4.

Figure II-3. NSPI's Risk Management Organizational Chart[7]



II.B.3.b.ii. Risk Management Documents

NSPI's risk management procedures are presented in the Fuel Manual. Provided as "links" to the Fuel Manual, the three key documents that contain NSPI's approach to risk management are (1) the Emera Credit Policy, (2) the NSPI Power Fuel Procurement Risk Management Policy & Procedures ("NSPI Risk Manual"), and (3) the Fuel Hedging Plan. We address each in turn. In all three, NSPI's governing risk management documents reasonably define key terms, roles, responsibilities, and approval processes for transacting for fuel and purchased power. We also address two other risk documents: (4) CROC's Mandate and (5) FST's Charter.

[7] NSPI Risk Manual, Appendix A.

Link 4 of the Fuel Manual contains the Emera Credit Policy, which governs the credit risk processes, approvals, and authorities applicable to commodity transactions and hedging activities for NSPI. The Emera Credit Policy's purpose is to focus on credit risk, which it defines as "[redacted]"[8] Importantly, the Emera Credit Policy further explains and offers more examples regarding credit risk, which is an important feature of good risk management policies; specifically, the Emera Credit Policy explains that financial risk includes "[redacted]"[9] It is reasonable and expected that NSPI, as part of a broader organization of Emera affiliates, is subject to an Emera-wide credit policy, as it is good practice for entities such as Emera to monitor and set limits and guidelines for transacting and the inherent credit risk that doing so accrues.

The Emera Credit Policy clearly identifies and defines the key roles for managing risk across the Emera-wide portfolio of affiliates, including the role of the Board of Directors, the Chief Risk Officer (to whom the CEO has delegated responsibility for implementing Emera's risk management strategy), the ERMC, and the ERM, as well as the roles of affiliates' front and back offices, including NSPI's.[10] Notably, the Emera Credit Policy tasks the NSPI front office with [redacted]."[11]

The Emera Credit Policy also includes clear credit limits for application to all counterparties with which Emera or its subsidiaries transact. For example, the Emera Credit Policy specifies a credit limit of [redacted] moreover, absent approval from senior management, NSPI and its affiliates are prohibited from extending credit to any entities that are not investment grade and from entering into contracts longer than 18 months.[12] Some exceptions to these credit limits exist, such as those for procurement of solid fuel, which the Emera Credit Policy appropriately recognizes as requiring a different approach.[13]

The second document that governs NSPI's risk management is the NSPI Risk Manual, which is Link 3 of the Fuel Manual. The NSPI Risk Manual addresses all risks NSPI faces in transacting for fuel and power, including commodity price market risk, supplier risk, country risk, foreign exchange risk, interest

8 Emera Credit Policy, page 1.
9 Emera Credit Policy, page 1.
10 Emera Credit Policy, pages 1 to 3.
11 Emera Credit Policy, page 3.
12 Emera Credit Policy, pages 4 to 5.
13 Emera Credit Policy, page 4.

rate risk, credit risk, environmental risk and operational risk.[14] The NSPI Risk Manual contains several key definitions.

- First, it defines CROC's essential role, noting that CROC is responsible for ensuring that "[redacted]" as well as other important responsibilities of CROC, such as reporting requirements to the NSPI Board of Directors and to ERMC.[15]

- Second, it defines the middle office's role, including its day-to-day role as steward of the risk management program and its functional separation from transactional activity at NSPI's front and back office. The Risk Manual also provides specificity regarding actions to be taken by the middle office in the event that there are material violations of the risk management program, and tasks the middle office with the quantification of credit exposures and review authority of credit applications, the approval of credit lines, and certain transactions with new counterparties.[16]

- Third, the Risk Manual defines the FST's role in governing NSPI's fuel procurement and hedging activities.[17] Fourth, the Risk Manual references other areas of the Fuel Manual as containing some of the terms related to risk management in fuel procurement that must be followed.[18] For example, NSPI's Solid Fuel Portfolio Process, which is Link 6 of the Fuel Manual, specifies that NSPI is not to commit more than [redacted]% of its solid fuel requirements, at minimum contract levels, to a single mine, that it will limit purchases from any single domestic mine to [redacted]% of NSPI's solid fuel requirements, and that it will strive to diversity the countries of origin of its solid fuel by limiting exposure to any one country of origin to [redacted]%.[19] Another example is the specific authority levels related to transactions and contracts, which define the specific thresholds for determining the approvals needed to conduct a particular transaction. Contracts over [redacted] require signatures from two members of the FST, for example, while transactions up to [redacted] can be signed for and approved by a Director of FERM.[20]

- The Fuel Manual also includes clear and appropriate transaction limits for individual marketers; e.g., energy marketers are limited in executing power purchases or sales of [redacted] MWh or less, anything beyond which requires additional approvals.[21] We reviewed these specific thresholds

14 NSPI Risk Manual, section 3.
15 NSPI Risk Manual, section 2.4.
16 NSPI Risk Manual, section 2.5.
17 NSPI Risk Manual, section 2.8.
18 NSPI Risk Manual, section 1.1.
19 NSPI Solid Fuel Portfolio Process, Link 6 of the Fuel Manual Revision 10, page 5.
20 NSPI Fuel Manual Revision 10, section 5.1.
21 NSPI Fuel Manual Revision 10, section 5.2, Appendix D.

and found them reasonable and clear, creating clear accountability and guidelines for FERM employees.

A third important risk management document, which is new for this Audit Period, is the Fuel Hedging Plan. We address NSPI's hedging activities in detail in a later chapter; here, we note that the Board approved the Fuel Hedging Plan, which contains the guidelines for NSPI to follow in hedging its exposure to variable fuel and power costs during the Rate Stability Period. We note that recommendations related to hedging transactional strategies are singled out in the Fuel Manual as requiring approval of the FST, regardless of the transactional value of the hedges.[22] We find this to be a reasonable approach, given the fact that NSPI's hedging approach in the Rate Stability Period was new and untested, and therefore warranted review and approval of the FST, which has responsibility for overseeing NSPI's fuel and power purchase transactional activities.

Two additional risk management documents warrant mention. The first is the Mandate of the CROC, which was last edited in February 2017. Given CROC's important role in managing and overseeing NSPI's risk management, it is worth noting the value and adequacy of CROC's governing document. The CROC Mandate defines CROC's membership to include NSPI's Vice President of Finance, the President and CEO, the COO, and the Executive Vice President, Regulatory, Legal and Business Planning,[23] while specifying a list of CROC meeting invitees, including the Director of FERM, the Director of Portfolio Optimization, and the Director of ERM, among other important figures in NSPI's procurement of fuels.[24] The CROC Mandate is clear that CROC is responsible for "[redacted]"[25] The CROC Mandate also specifies the responsibilities of CROC, including its role in ensuring that the middle office executes its responsibilities, such as conducting regular reviews of NSPI's credit and country risk exposures.[26] We found the CROC Mandate sufficiently clear and specific regarding CROC's roles and responsibilities.

The final risk document we will discuss is the FST Charter. Again, the FST plays a key role in ensuring NSPI's transactions and contracts for fuel and purchased power are within NSPI's guidelines by reviewing certain transactions and proposed contracts. FST's Charter is an adequate documentation of FST's purpose, responsibilities, and makeup. FST's purpose is to govern fuel procurement and hedging[27] by reviewing and approving recommendations related to hedging and procurement of fuel and purchased power, reviewing fuel strategy and planning, ensuring that procurement of fuel and purchased power are in line with the most recent fuel forecast, and reviewing internal audit reports of NSPI's fuel procurement

22 NSPI Fuel Manual Revision 10, section 5.1.
23 CROC Mandate, page 2.
24 CROC Mandate, page 2.
25 CROC Mandate, page 1.
26 CROC Mandate, page 1.
27 FST Charter, section 5.

processes and functions, among other things.[28] FST is composed of NSPI's President and CEO, the COO, the Vice President of Fuels and Energy, the Vice President of Finance, the Senior Director of Power Production, and the Director of FERM.[29] Like the CROC Mandate, we found the FST Charter to be both an important and adequate document in NSPI's risk management process.

II.B.3.b.iii. Risk Management Systems

NSPI uses Allegro's Energy Trading and Risk Management (ETRM) software as its energy trading and risk management system; this system replaced Nucleus, which was phased out at the end of the last Audit Period. ETRM is used for deal capture, credit and market risk monitoring, and settlement. The Allegro database captures NSPI's physical and financial gas, power, coal, and oil positions centrally, as well as current forward market pricing and historical spot and forward market data. The middle office retains the responsibility for maintaining the Allegro database and updating changes to the database content and is also tasked with being the "owner" of Allegro and of the integrity of the data.[30]

NSPI also uses Aligne Fuels to manage heavy fuel oil (HFO), light fuel oil (LFO), diesel, and solid fuel information. Aligne Fuels is an off-the-shelf commercial software system designed for the power generation industry to manage fuel information from procurement through to consumption and account for the expense. Generation and fuel consumption data are collected from each plant and exported to the Aligne Fuels database. Information on fuel suppliers, contracts, and fuel types is administered within Aligne Fuels. Like Allegro, Aligne interacts with NSPI's other systems, including the Oracle billing system; every month, fuel data from Aligne are uploaded to Oracle F for financial reporting purposes.[31]

NSPI's risk management processes also define key roles of the back office and its segregation from the front office.[32] We discuss these issues in more detail in a later chapter.

II.B.3.b.iv. Audit Period Results

While we discuss in our FAM Accounting chapter more detail about NSPI's controls and their performance during the Audit Period, we note here a few findings from our review of Audit Period data. First, we observed that NSPI takes the role of the FST seriously and that FST functioned as required and designed in reviewing and approving numerous transactions during the Audit Period. As we discuss in fuel-specific chapters of this report, we observed numerous instances of FERM presenting to FST a proposed contract and/or transaction for FST review and approval. The presentations generally included a review of the rationale for the transaction, an analysis of how the proposed transaction fit within NSPI's fuel procurement strategy, how the transaction addressed NSPI's needs as identified in the most recent fuels forecast, and the risks of each transaction, including credit and country risks.

[28] FST Charter, section 6.
[29] FST Charter, section 7.
[30] NSPI Risk Manual, section 6.1.
[31] NSPI Risk Manual, section 6.1.
[32] NSPI Risk Manual, section 6.2.

Second, there were two violations of NSPI's risk management policies during the Audit Period:

- In August 2016, NSPI sold power in the amount of [redacted]. The middle office determined that it did not require mitigating action for the transaction, as [redacted] and its affiliates have been long-standing counterparties of NSPI with strong creditworthiness and with no past performance issues. The middle office discussed the matter with the front office and reminded them of the importance of monitoring positions and seeking credit approval in advance of such transactions. The middle office also reported the transaction as a violation of the Emera Credit Policy to CROC and the ERMC. As there has been little history of credit violations at NSPI and there were no concerns about [redacted] creditworthiness, no further action was required with respect to this particular transaction. The Director, Fuels, reviewed the Emera Credit Policy with the marketing desk and its obligation to seek approval for exposure creating transactions in advance of transacting where an opportunity arises and credit limits could be exceeded. We found NSPI's explanation for this violation to be reasonable; as we discuss in the chapter on Purchased Power and Sales, [redacted] is a frequent counterparty of NSPI's; also, we note that subsequent to this event, FERM sought a credit limit of [redacted] for future transactions—this credit limit was approved in June 2017. Nevertheless, as we discuss below, it should be NSPI's goal to have no violations of its risk management protocols, so this incident merits watching going forward.
- In October 2017, there was a violation of the Emera Credit Policy when NSPI sold petcoke to [redacted]. The [redacted] transaction allowed NSPI to seek financial security from [redacted] in advance of the delivery, but NSPI did not exercise the option, nor did NSPI seek credit approval for such a waiver in advance of physical delivery. In response, FERM halted deliveries of the product after one day of delivery and requested financial security from [redacted]. [redacted] responded by pre-paying for the entirety of the contracted petcoke, allowing NSPI to continue with deliveries. The middle office did not require any mitigating action due to the small amount of risk exposure inherent in such a small transaction, but nevertheless reviewed with FERM the required processes in place—i.e., requiring FERM to seek approval for such transactions in advance. The middle office also reported the incident to CROC. We found NSPI's explanation of and response to this incident to be reasonable; indeed, this was not a large transaction, and it was a rare transaction in that NSPI was selling petcoke, an infrequent transactional occurrence.

Despite the reasonable explanations and NSPI management responses, any violation of risk management guidelines should get NSPI's attention. These two violations show that even when a reasonable risk management program is in place, including regular training, and an entity has gone a long stretch without any violations—we note that in 2014 and 2015, NSPI had zero violations of its risk protocols[33]—violations can occur. We observed no evidence to suggest that these violations were

[33] 2014-2015 Liberty FAM Audit Report, page I-24.

anything but oversights by otherwise-compliant personnel at FERM; nevertheless, they should serve as a reminder that risk management has to be part of FERM employees' decision making, and we would monitor NSPI's compliance with its risk protocols going forward.

II.B.3.c. Internal Auditing

NSPI's internal audit practices are addressed in the final chapter of our report.

II.B.4. Liberty 2014-2015 Recommendations

In its 2014–2015 Audit Report, the previous fuel auditor offered eight recommendations related to NSPI's organization, staffing, and controls. We address each recommendation in this section.

Liberty's first recommendation was for NSPI to "[p]rovide clarity in the division of responsibilities of the two directors reporting to the new Vice President, Fuels and Energy."[34] NSPI agreed with this recommendation and developed and provided job descriptions for both the Director of Portfolio Optimization and the Director of Fuels.[35] We reviewed these two job descriptions and found that they provided adequate delineation of responsibilities, clear accountabilities for each role, and organizational interactions between the two roles and internal and external NSPI resources.

Liberty's second recommendation was as follows: "Make fuel and energy based measures the predominant basis for the incentive compensation in all of FERM and for the Vice President to [whom] FERM reports."[36] NSPI agreed with this recommendation, noting that "fuel and energy-based measures have been adopted as the predominant basis for the incentive compensation in 2017" for FERM employees.[37] We confirmed that this was the case, as discussed above, and found NSPI's specified categories of fuel and purchased power incentives to be reasonable. We note that NSPI created an exception for the Vice President, Commercial, from this recommendation, noting that this employee's compensation structure is determined by NSPI's Board of Directors. It appears to us that FERM's compensation structure provides adequate and proper incentives for FERM to pursue and achieve fuel cost savings for NSPI customers.

Liberty's third recommendation was: "With the support of the Human Resources department, prepare a succession plan reflecting the unusual pace of change in fuel and energy personnel and the need for greater focus on preparing incumbent FERM members for senior leadership in fuel and energy management."[38] NSPI agreed with this recommendation and developed a succession plan for all roles

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34 Liberty 2014-2015 Audit Report, page I-32.
35 NSPI 2016 FAM Audit Action Plan, page 4, lines 17 to 29.
36 Liberty 2014-2015 Audit Report, page I-32.
37 NSPI 2016 FAM Audit Action Plan, page 5, lines 1–11.
38 Liberty 2014-2015 Audit Report, page I-33.

within FERM.[39] As we discuss in detail above, we found NSPI's response to this recommendation to be adequate.

Liberty's fourth recommendation was to "[c]omplete the pending review of Quarterly Fuel Manual Compliance and implementation of the last audit's recommendation; resume and expand the supplier performance evaluations."[40] NSPI agreed with this recommendation, noting that Revision 10 of the Fuel Manual's compliance sheets was an update to reflect all changes made.[41] NSPI explained to us that they have committed to continue to review and update processes as and when necessary to ensure they reflect current practices. We found NSPI's response to this recommendation to be reasonable and note that, given the dynamic nature of the Fuel Manual, this recommendation will require NSPI's ongoing attention.

Liberty's fifth recommendation was for NSPI to "[p]repare and submit for Small Working Group review a complete, unified set of Fuel Manual changes by September 1, 2016."[42] NSPI agreed with this recommendation and provided the FAM Small Working Group an overview of all changes made to the most recent revision to the Fuel Manual (Revision 10) on NSPI's FTP site.[43] Moreover, NSPI presented Revision 10 of the Fuel Manual to the FAM Small Working Group on March 9, 2017, and May 17, 2017, inviting members to comment. In response to comments received, NSPI provided written feedback on July 21, 2017. NSPI then filed Revision 10 with the Board in October 2017, allowing stakeholders another opportunity to comment. We found this approach by NSPI a reasonable response to this recommendation, and we find that this process is a good one that should be continued going forward, as it increases transparency of NSPI's Fuel Manual revision process and allows stakeholders an additional forum to provide feedback.

Liberty's sixth recommendation was to "[i]dentify and correct the root causes of Audit Period failures in record retention and reporting."[44] NSPI agreed with this recommendation and, after reviewing issues identified by Liberty and processes to mitigate those issues, focused its response on two areas.[45] The first area was record keeping for affiliate natural gas transactions. NSPI implemented an additional compliance process to help ensure the accuracy of transactions recorded in its affiliate trade logs. It noted to us that this process was audited in its recent Affiliate Code of Conduct Audit and that no concerns related to record keeping or documentation were noted. The second area on which NSPI focused was the process by which it shares its vast amount of transaction data with its external fuel auditor. NSPI developed a SharePoint site for this Audit Period's fuel audit, which we found to be practical, effective, and thorough. Overall, we find NSPI's response to this recommendation to be reasonable, and we note our general finding here that NSPI's documentation was reasonable during this Audit Period; if we requested

39 NSPI 2016 FAM Audit Action Plan, page 5, lines 13–22.
40 Liberty 2014-2015 Audit Report, page I-33.
41 NSPI 2016 FAM Audit Action Plan, page 5 line 24 to page 6 line 6.
42 Liberty 2014-2015 Audit Report, page I-34.
43 NSPI 2016 FAM Audit Action Plan, page 6, lines 8–23.
44 Liberty 2014-2015 Audit Report, page I-34.
45 NSPI 2016 FAM Audit Action Plan, page 6 line 25 to page 8 line 5.

documentation of some transaction or process, NSPI was able to provide such documentation. That appears to be an important step forward from the last Audit Period, given what we read in the previous fuel auditor's report. This is not to say that NSPI did not have any errors in its data—we note a few elsewhere in this report—but NSPI had sufficient documentation available to respond to our requests for information and to diagnose and correct the few data issues we did identify.

Liberty's seventh recommendation was to "[i]ncorporate into the transition of Allegro system access testing and mark-to-market triggers; formalize country and credit risk reviews in risk procedures."[46] NSPI agreed with this recommendation and updated its policies. First, NSPI incorporated system access testing into Allegro, which ensured that individual business units within NSPI/Emera would not have access to other business units' information. NSPI has introduced procedures to re-test this security whenever Allegro is updated or changed, and the middle office reviews on both weekly and monthly bases the accessibility of all Allegro users to prevent any unauthorized access. NSPI has also introduced a new process for solid fuel credit exposure tracking by inputting all solid fuel transactions into Allegro. This new process includes tracking of mark-to-market exposure, and each solid fuel supplier has a specified exposure threshold limit. In 2017, NSPI introduced an exposure threshold notification process to report such solid fuel exposures to CROC and NSPI senior management.[47] We reviewed this new process and found it to be reasonable and proactive in anticipating impacts driven by substantial changes in mark-to-market exposure. Finally, NSPI responded to the recommendation to formalize country and credit reviews in its risk procedures by revising the CROC Mandate to include regular credit analyses on active and contemplated suppliers by the middle office, as well as regular assessments of country risk by the middle office on all high-risk countries. We find this to be a reasonable response to the previous fuel auditor's recommendation, as it codifies these practices and creates accountability for CROC to conduct these analyses every 18 months.[48]

Liberty's eighth recommendation was: "Conduct an overall assessment of biomass procurement and management needs and produce a plan for long-term operation that includes an approach to the use of methods, procedures, systems and controls like that applied to other fossil procurement."[49] NSPI agreed with this recommendation and, in response, updated its biomass procurement and management processes in Revision 10 of the Fuel Manual.[50] We find NSPI's response to this recommendation to be reasonable, and we address the specifics of NSPI's biomass procurement and supply management processes in the two chapters on solid fuel, later in this report.

46 Liberty 2014-2015 Audit Report, page I-35.

47 NSPI 2016 FAM Audit Action Plan, page 8 line 7 to page 9 line 22; see also CROC Mandate, page 1.

48 NSPI 2016 FAM Audit Action Plan, page 9 line 24 to page 10 line 16.

49 Liberty 2014-2015 Audit Report, page I-36.

50 NSPI 2016 FAM Audit Action Plan, page 10, lines 18–29.

II.C. Conclusions

Conclusion II-1: NSPI's organizational structure is reasonable and well defined, with the roles across the organization adequately specified, including responsibilities, which can help create an environment of accountability.

Conclusion II-2: FERM is well staffed with experienced personnel, particularly in key leadership positions across the department. Moreover, FERM personnel's diverse backgrounds—including some longer-tenured FERM employees mixed with experienced employees hired externally with useful, varied experience—can provide benefits for FAM customers. In both cases, we observed the FERM employees to be competent and knowledgeable.

Conclusion II-3: NSPI's performance management program meets industry standards and is well integrated with NSPI's compensation programs, training efforts, and succession planning.

Conclusion II-4: NSPI's training programs are adequate and have a proper focus on both regular, annual training in crucial risk management and code of conduct issues, as well as employee-specific training to further develop NSPI's human capital. Training materials were sufficiently detailed, contained very clear definitions and guidelines, and were easily understandable.

Conclusion II-5: NSPI's performance-based incentive programs create important and appropriate incentives for FERM employees to perform in their positions in ways that help minimize costs to NSPI ratepayers. Both the Commercial Incentive and Short-Term Incentive Programs balance both the individual's performance with the performance of the larger entity—FERM in the former case, and NSPI in the latter.

Conclusion II-6: NSPI's Commercial Incentive Program appropriately ties compensation under the program to FERM's ability to reduce FAM costs. NSPI's specification of a variety of categories that help reduce FAM costs are appropriate, although one of those categories should be clarified: the monetization of available and economic surplus generation, which would reward FERM and its employees for selling excess and economic power exports showing benefits of [redacted] or greater. While we agree this is a reasonable metric for inclusion in the Commercial Incentive Plan, we have a recommendation to clarify that the benefits are realized benefits, not forecasted benefits—as we explain in the Purchased Power and Sales chapter, NSPI's power export decisions often involve estimates of revenues and costs, which means realized benefits can differ from forecasted benefits. NSPI indicated that the metric was implemented based on actual and agreed that the metric would benefit from additional clarity. (Recommendation)

Conclusion II-7: NSPI's new succession plan for FERM employees is a useful enhancement that will help NSPI address short-term disruptions in its labor force, help FERM employees to define their desired roles in the future, assist employees in developing needed skills and experience to enter those roles, and assist NSPI in managing its long-term human resources.

Conclusion II-8: NSPI's Fuel Manual is a useful tool that holds NSPI's employees accountable to its policies and for the Board to hold NSPI accountable for its decisions related to fuel and power purchasing. The Fuel Manual contains a substantial amount of information about the goals and guidelines applicable to NSPI and FERM employees that should serve as the guiding document on a day-to-day basis.

Conclusion II-9: NSPI's risk management processes, procedures, organization, and documentation are reasonable and should encourage effective risk management. As part of a broader corporate entity with multiple affiliates (Emera), NSPI has risk management that is appropriately is driven in part by Emera-wide policy, particularly related to credit risk. NSPI's documentation of risk management assigns sufficient levels of accountability for key personnel at NSPI and provides clear guidelines regarding definitions of risk, transaction and contract approval thresholds, and reporting procedures.

Conclusion II-10: There were two instances during the Audit Period when NSPI's fuel and power purchasing activities violated NSPI's risk protocols. In both cases, the problem was discovered in short order, and NSPI management and NSPI's middle office took swift and appropriate action to address the incidents. Moreover, in both cases, we agreed with NSPI that the incidents were driven by mitigating circumstances: in one case, a frequent counterparty was extended credit beyond its limit (which was, incidentally, zero), and in another, an infrequent transaction (sale of petcoke) for a small quantity of fuel led to a violation of the credit policy. Despite the reasonableness of NSPI's response and the mitigating circumstances that led to the two incidents, any violation of risk management procedures warrants attention and should serve as a reminder to NSPI that risk management has to be part of FERM employees' decision making. We would highlight NSPI's compliance with its risk protocols as a particularly important area to monitor going forward.

Conclusion II-11: NSPI responded adequately to each of the previous fuel auditor's eight recommendations. In doing so, NSPI made several important improvements to its processes, including introduction of a succession plan for FERM, improvements to the incentive-based compensation programs, additional transparency in the Fuel Manual revision process, improvements in record retention, and enhancements to risk management.

II.D. Recommendations

Recommendation II-1: NSPI should clarify in its Commercial Incentive Program that the category regarding "monetization of available and economic surplus generation"—which would reward FERM and its employees for selling excess and economic power exports showing benefits of [redacted] or greater—should be clarified to specify that the benefits are *realized* benefits, not forecasted benefits—as we explain in the Purchased Power and Sales chapter, NSPI's power export decisions often involve estimates of revenues and costs, which means realized benefits can differ from forecasted benefits.

III. Forecasting and Fuel Supply Planning

III.A. Background

The purpose of the Fuel Adjustment Mechanism—to ensure that power rates reflect the actual cost of the fuel used to produce the power and not simply a forecast of fuel need—highlights the importance of accurately forecasting the energy and peak capacity requirements of NSPI's in-province customers and the least cost supply plan to satisfy them. This chapter addresses NSPI's forecasting and planning processes and practices during the Audit Period.

III.B. Findings

The load forecast forms the basis for fuel supply planning, investment planning, and overall operating activities of NSPI required to serve customer load over a 10-year time horizon. NSPI's load forecast is the aggregate of separate forecasts for each customer class. NSPI uses Statistically Adjusted End-Use (SAE) models to forecast the load for the residential and commercial rate classes; an econometric model for the industrial class load forecast; and customer-specific forecasts for some individual large customers. The forecasting models NSPI uses incorporate analyses of sales history and take into consideration weather, end-use saturations and efficiencies, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other means to supply customers' loads. The customer class forecasts are ultimately aggregated to develop an energy forecast for the province, also referred to as a Net System Requirement (NSR), which represents in-province sales plus associated losses, net of exports and station service. NSPI also forecasts peak hourly demand, defined as the highest single hourly average demand experienced in a year, based on the forecast energy requirements and expected load shapes. The peak hourly demand includes both firm and interruptible loads. An annual forecast broken out by month is prepared each year at the end of the second quarter. The results are documented in an annual Load Forecast Report, which is filed with the NSUARB each year.[1]

The quantities of the various fuels required to supply the forecast load at the lowest possible cost are estimated using a model that simulates the operation of each generating unit and their dispatch in economic merit order (cost), subject to transmission security constraints. NSPI currently uses a commercially available, transmission security-constrained chronological (hourly) economic dispatch model called PLEXOS. PLEXOS is a commitment-based, security constrained, chronological dispatch optimization software, which is supplied and maintained by Energy Exemplar LLC.

[1] NSPI's load forecast methodology for the 2017 FAM forecast changed from the econometric approach used in prior years to the SAE methodology used in NSPI's annual 10-year load forecast.

To forecast the amount of each fuel required to operate the generating units over a 10-year forecast period, the model must consider (1) the technical and economic characteristics of NSPI's generating units; (2) a price forecast for each of the fuels used in generation; (3) various other assumptions regarding NSPI's units operation (such as alternative fuel blends and associated emissions); (4) purchased power costs; and (5) the topology and capacity of the transmission system. To account for future changes in the Nova Scotia power grid over the forecast period, the model requires a schedule of generating unit additions and retirements, as well as a transmission expansion plan. Based on this information, PLEXOS' optimization algorithms find the lowest cost dispatch that complies with mandated emissions limits, producing an estimate of the energy generated by and the fuel requirements of each generating unit, and the total quantities of each fuel required to operate NSPI's generating units. The annual fuel budget is calculated based on the quantities of each fuel and its respective price. NSPI forecasts its fuel requirements and budget quarterly, thus requiring a new PLEXOS run with the same frequency.

PLEXOS is also used to perform an environmentally constrained seven-day-ahead optimum dispatch forecast as a starting point for the day ahead unit-commitment and dispatch using another model (GenOps).

III.B.1. Overall Adequacy of Forecasting Models and Data

III.B.1.a. Energy Sales Forecasting

NSPI forecasts system load (energy) and system peak demand using separate models for its residential, commercial, and industrial sector customers. NSPI's Load Forecaster and Supervisor of Load and Revenue Forecasting are responsible for the preparation of the load forecast.

The residential sales forecast is the product of the residential average use forecast and a forecast of customer count. Historical load data used in the model consist of 10 years of monthly billed sales data. Economic data (GDP, employment, disposable income, consumer spending, housing starts) are based on the Conference Board of Canada 20-year outlook, which is updated annually. Appliance energy use information (energy intensities and saturations) come from Natural Resources Canada ("NRCan") and the US Energy Information Administration (EIA) for New England, adjusted for Nova Scotia (also updated annually). Weather data are based on 10 years of Environment Canada hourly temperature records to produce normal monthly Heating Degree Day and Cooling Degree Day, with an 18^{o} C base.[2]

During the 10-year forecast period, residential customer count is expected to grow, along with increased saturation of heat pump heating and decreased saturation of electric resistance heating. Overall, in the 2017 load forecast, the residential sector load is anticipated to grow slightly (0.2% annually) during the 10-year forecast period; after adjusting for the effects of Demand-Side Management (DSM).

NSPI's commercial SAE models express monthly sales as a function of heating, cooling, and other loads. Historical load data used in the model consists of 10 years of monthly billed sales data. Like the

2 2017 Load Forecast Report, May 31, 2017.

residential model, the load forecasts for the Small General Service and General Service class models are based on a monthly SAE average use model and a separate customer count forecast. The Small General Service and General Service rate class forecast models are estimated on a total monthly sales basis, where total monthly billed sales are a function of total monthly heating requirements, cooling requirements, and other uses. NSPI expects Small General Service load to grow at 2% per year during the 10-year forecast, driven by increased customer count and growing information technology (IT) energy use. While robust economic growth in Nova Scotia seems to support this growth estimate, increased penetration of e-commerce could shift the distribution of buildings from retail stores to more fulfilment warehouses, reducing projects' Small General Service load growth.[3] General Service sales are expected to decline by 0.3% annually during the 10-year forecast period due to declining customer numbers, which will diminish heating, lighting, and refrigeration intensities due to increased equipment efficiencies. Large General Service sales are forecast using a combination of historical information and customer surveys to determine electricity requirements over the next three years. In the absence of information on individual customer load changes via survey or public information, load levels are forecast as flat.

The SAE models NSPI used in its forecasting of residential and commercial load are well suited to accommodate the growing penetration of energy-efficient and demand-response technologies and improvements of these technologies over time.

The end-use variables in the residential and commercial SAE models are based on end-use intensity projections that capture expected end-use intensity trends. Over the 10-year forecast horizon, actual end-use intensities can vary from projected trends due to multiple factors, including changes in the commercial availability and price of new technologies, tax and cash incentives designed to accelerate the adoption of new technology, etc. Examples of these changes, relatively underestimated in forecasting until recently, are reductions in the price and increased availability of LED lighting and smart thermostats. Changing trends in preference for multi-unit over single unit housing in new household formation could also significantly affect energy consumption for new customers over the forecast horizon.

The Small Industrial and Medium Industrial class load forecasting models are econometric-based models, with Provincial GDP as the primary economic variable for Small Industrial and manufacturing employment for the Medium Industrial class. The models were developed using monthly sales information to align their timeframes with those of the residential and commercial forecast models, and thus be able to produce a joint end-use based peak demand forecast. Sales for the Small Industrial rate class have been flat for the last 10 years but are expected to grow at 1% annually over the forecast period as a result of underlying economic growth. Sales for the Medium Industrial class, in decline since the 2008 recession, are expected to remain stable or to increase slightly during the forecast period.

The load forecasting models for customers served under the Large Industrial, Large Industrial Interruptible, Generation Replacement and Load Following, One-Part Real-Time Pricing, and Load

[3] Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, Energy Technologies Area, January 2017, page 106.

Retention tariffs are based on historical sales information combined with customer surveys used to determine energy requirements for the next three-year period based on planned production levels or equipment changes. These forecasting approaches can provide a reasonably accurate basis for forecasting load, as long as intelligence gathering on future changes in load requirements of large customers are diligently conducted. The same diligence in regular information gathering might be advisable in the case of municipal loads, as municipalities can buy electricity from other suppliers.

Conservation and Energy Efficiency effects are incorporated into the forecast by reducing the load forecast by Efficiency One's annual projected savings for each sector (residential, commercial, and industrial).

III.B.1.b. Net System Requirement Forecast

The NSR is the energy required to supply the sum of the residential, commercial, and industrial electricity sales, plus the associated system losses with Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included in NSR. The NSR for the province in 2016 declined by 2.6%, primarily due to reduced residential and commercial sales and a mild winter. For the period 2017–2018, the NSR was forecast to remain at the 2016 level due to the effect of DSM, without which growth was expected to grow by 0.7% annually.

III.B.1.c. System Losses and Unbilled Sales

Physical losses in NSPI's transmission and distribution system plus energy generated and sold but not billed averaged 6.8% of NSR over the five years prior to 2017. System losses and unbilled sales are expected to remain in the 6.0–7.0% range over the forecast period.

III.B.1.d. Peak Demand Forecasting

The long-term system peak forecast for the accrued classes is derived through a linear regression model that relates monthly peak demand (excluding large customer contribution) to heating, cooling, and base load requirements derived from the class sales forecast models for "Residential," "Small General Service," and "General Service" customers. The monthly heating and cooling requirements from the class sales models are normalized for the number of days and hours for each month and interacted with peak-day Heating Degree Day and Cooling Degree Day measurements. The peak model's base load variable captures the impact of loads that are not weather sensitive on peak, including residential and commercial other (non-cooling and heating) lumped end-use components plus industrial and unmetered sales. The contribution from large customer classes (commercial and industrial) is calculated from historical coincident load factors for each of the rate classes and added to the forecast accrued class to get the total system peak.

The model assumes that the peak is driven by weather and that the loads considered in the base load variable are averaged for the number of days in the month, thus representing an average load, which is not affected by weather. We note that this assumption is potentially incorrect for some large commercial and industrial end-use loads such as process refrigeration and heating included in this category, but not considered in the energy model's end-use variables on which the peak model relies to account for the impact of weather.[4] Further, the model does not specifically address the impact on these end-uses of demand-response or energy efficiency and their changing impact over the forecast period. Also, it is not clear how the historical effects of demand response (DR) and energy efficiency (EE) embedded in the historical data used in the regression model are established to avoid double counting in the forecast period.

After accounting for DR and EE savings, the system peak is forecast to grow at a rate of 0.6% annually. In summary, NSPI's peak load forecasting model is more simplistic than its energy sales forecasting models; thus, additional uncertainty should be ascribed to its peak demand predictions.

III.B.1.d.i. Accuracy of NSPI's Load and Peak Demand Forecasts

Given the structure of NSPI's forecasting models, the main contributing factors to variance between forecast and actual energy consumption and peak demand are:

- Lower number of new customers in both residential and commercial classes
- Lower penetration of heat pumps in the residential class
- Low oil prices reducing the number of customers switching to electric heat
- Lower GDP growth
- Lower PHP consumption
- Lower unmetered consumption due to LED lights

The accuracy of the forecast of the Total System Requirement for the Audit Period years (2016–2017) was slightly above and slightly below 3%, as shown in Figure III-1. This level of accuracy is not unreasonable and is comparable to the forecast accuracy of other utilities.

Figure III-1. Comparison of Total System Requirement Forecast vs. Actual (MWh)

Year	Actual	Forecast	Variance (%)
2016	10,839,306	11,198,986	-3.2
2017	10,976,629	11,284,796	-2.7

NSPI overestimated its Peak Load in its forecasts during the 2016–2017 Audit Period: its forecast was slightly higher than its actual peak load in 2016 and over 5% higher than actual in 2017, as shown in Figure III-2.

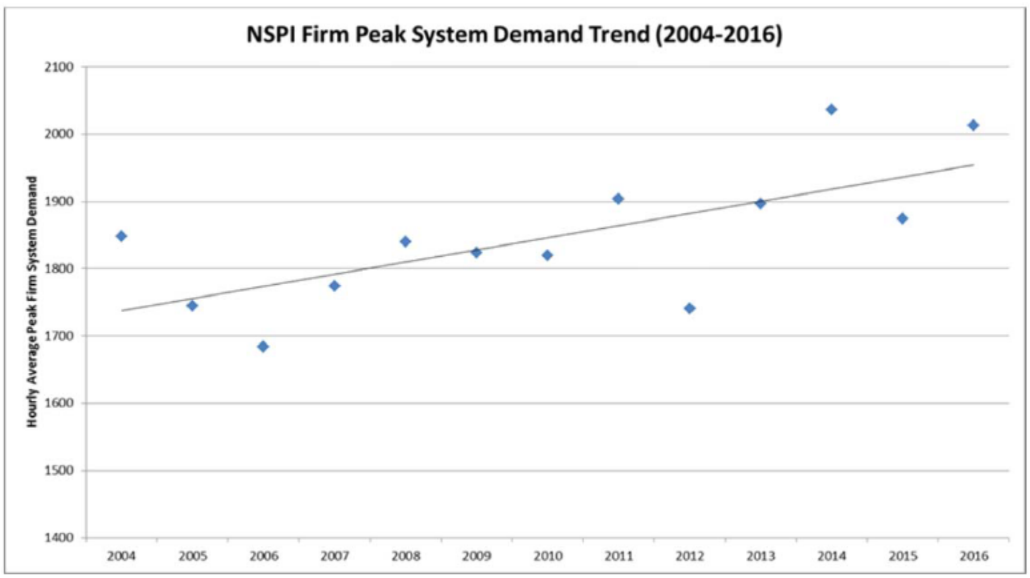
[4] Cooling and heating refers to HVAC load, while refrigeration refers to commercial and industrial refrigeration. NSPI includes refrigeration with the base load, which is not supposed to be weather sensitive; however, refrigeration of food and other perishables typically is weather sensitive.

Figure III-2. NSPI's Estimated and Actual Peak Loads (MW, 2016 and 2017)

Year	NSPI's Actual Peak Load	NSPI's Estimated Peak Load	Variance (%)
2016	2,111	2,118	–0.33
2017	2,018	2,130	–5.26

However, given the large year-to-year variability of NSPI peak system demand, as illustrated in Figure III-3, a forecast vs. actual variance of the magnitude observed during the Audit Period should not be a cause for alarm but suggest caution in making long-term decisions based on a single year peak demand forecast values.

Figure III-3. NSPI Peak System Demand Trend[5]



III.B.1.d.ii. Comparison of 2016 and 2017 Load Forecasts

Pages 8 and 9 of the 2017 load forecast report have contradictory statements regarding the low growth of the residential sector for the 10-year forecast period. Page 8 states that residential sector load is anticipated to decline slightly during 10-year forecast period. However, page 9 states that over the 10-year forecast, residential load is expected to increase by 0.2% annually. In either case, this represents a reduction in the expectation of annual growth found in the 2016 Load Forecast Report, which projected an annual growth rate of 0.5%.

The sales forecast for the Small General Service in the 2017 Load Forecast Report is also significantly different from that of the 2016 Load Forecast Report. The 2017 Report projects this class's sales to grow at an average 2% per year over the 10-year forecast period, whereas the 2016 forecast projected an annual decline. The reason for this change in the 2017 Report was the impact of DSM

5 NSPI 10-Year System Outlook, Figure 9.

overcoming a slow rate of growth. NSPI attributes the reversal to increased customer count and energy use by growing information technology.

The 2017 General Service sales forecast predicts a 0.3% annual decrease—steeper than the 0.2% annual decrease predicted in the 2016 forecast. As in the prior year's forecast, the decline is attributed to a decline in customer numbers in the class and increased efficiencies in equipment, lighting, and refrigeration.

The large general service forecast is expected to stay flat for the 10-year forecast period, which is similar to what was expected in the 2016 forecast. The small industrial sales 2017 forecast projects growth of 1% annually over the forecast period, which is attributed to underlying economic growth. This contrasts with the prior year's forecast, which projected no growth during the forecast period. The medium industrial 2017 forecast sales projects are expected to remain relatively stable, with some underlying economic growth offset by DSM. The trend in the 2017 forecast over the forecast period is similar to the one in the 2016 forecast except for slightly lower growth. The 2016 and 2017 load forecasts for other industrial rate classes, including large industrial, large industrial interruptible, generation replacement, and load following, are each expected to remain flat for the forecast period due to the absence of survey or general public information on energy requirements expectations.

III.B.2. Fuel and Purchased Power Forecasting

Fuel and Purchased Power (F&PP) forecasts for the rate stability period are prepared annually and updated quarterly. The results of these forecasts are used in fuel purchasing and the review and rebalancing of the hedging plan. F&PP forecasts are conducted using PLEXOS.

The first F&PP forecast for the 2017–2019 Rate Stability Period was produced in the first quarter of 2016 and provided the basis for the budget and targets for the Rate Stability Period. Improved F&PP forecasts—with system assumptions and commodity prices updates—were completed beginning in the third quarter of 2016 and for every subsequent quarter through 2017 for the Rate Stability Period and 2020.

The F&PP forecasting process consist of two distinct components: the PLEXOS dispatch simulation modelling and the financial model production. This section of the report covers only the methodology, data sources, and results of the PLEXOS forecast.

The results of the PLEXOS dispatch simulation modelling provide the quantities of the various fuels required to supply the forecast load at the lowest possible cost. The F&PP forecasts are reviewed with the FERM and Portfolio Optimization management and the Fuel Strategy Table (FST), as per the Fuel Manual.

The PLEXOS forecast of the amount of each fuel required to operate the generating units over the Rate Stability Period, as well as in 2020, takes into consideration the technical and economic characteristics of NSPI's generating units; a price forecast for each of the fuels used in generation; and various other assumptions regarding NSPI's units operation (such as alternative fuel blends and associated emissions), purchased power costs, and the topology and capacity of the transmission system.

In its 10-Year System Outlook, NSPI relies on PLEXOS to forecast the long-term utilization of its thermal generating fleet. The forecast of each generating unit Utilization Factor (UF) over the 10-year plan, in addition to accounting for future changes in the Nova Scotia power grid over the forecast period, the model also requires a schedule of generating unit additions and retirements, as well as a transmission expansion plan. However, the Outlook report does not explicitly discuss nor documents whether the resulting system plan and unit utilization forecast represents the plan with the lowest production cost of a number of alternative resource plans considered by NSPI.

III.B.2.a. Inputs and Assumptions used with PLEXOS in Fuel and Purchased Power Forecasting

To accurately simulate the operation of the NSPI system, including accurate modelling of the transmission security constraints limiting the economic dispatch of its generating units and its imports and exports, PLEXOS requires highly detailed information about the following:

- System load forecast, which includes hourly power requirements for the forecast period (ten years for the 10-Year System Outlook, two years for the FAM forecasts, and one week for day-ahead unit commitment and dispatch)
- Transmission characteristics, including nodal system configuration and individual transmission line characteristics
- Fuel-price forecasts, which provide an estimate of the delivered price of each fuel to NSPI for each of NSPI's generating plants, over the forecast horizon, using contract prices for fuel and transportation already contracted and forward-market prices for fuel and transportation not yet contracted
- NSPI's generating unit characteristics and availability, including heat rates, programmed maintenance outages, maximum capacities, deration factors, DAFOR, variable O&M costs, and mercury abatement costs
- Other operating costs, such as emission fees, water use fees, solid fuel pile management costs, rail car leases, pier volume adjustments, and incremental trucking costs
- Volume and price assumptions for power exports and power imports. Export volume limits are set at prior year's volumes and are priced at [redacted] Import prices from New Brunswick are priced at [redacted]
- Wind and hydroelectric monthly production are estimated outside of PLEXOS, based on historical information and inputted into PLEXOS. Hourly wind energy production profiles are based on averages of the last three years' production data for each telemetered wind project or based on the geographically nearest telemetered wind site.

> The hourly wind generation profiles are input into PLEXOS together with monthly energy and peak generation forecast information for each wind generator. Hydroelectric production estimates for each unit use a 23-year rolling average, adjusting the average for unit additions, decommissioning, and extended unavailability for inspections and maintenance. Section 4.10 of the FAM Fuel Forecasting methodology in Appendix B of the POA does not explain how the hydro production estimates are used in PLEXOS; although the model is capable of modeling energy constrained resources. The use of historical wind and hydroelectric production data, to forecast production from these resources, assumes a certain regularity in Nova Scotia weather patterns which may not hold true over the long term. While the 23 years of hydroelectric history provides a reasonably large enough sample of precipitation variation over time, the three year average wind production histories are probably too short to provide a reliable basis for forecasting of wind energy production, and lacks the predictive power to anticipate potentially significant year to year variations from historical monthly averages.

III.B.2.b. Environmental Considerations in Unit Commitment and Dispatch Forecasting

NSPI uses two systems to plan for the most economical way to operate its generation fleet while balancing the fuel sources deployed to serve its load without exceeding emissions caps. First, PLEXOS is used by the Portfolio Optimization Group to perform optimized annual and quarterly forecasts of generation dispatch and fuel use. Second, GenOps is used to plan the daily dispatch; however, GenOps' ability to capture environmental emission effects is limited to the cost of powdered activated carbon PAC. Additionally, NSPI applies an Emission Shadow Price (ESP) to the cost of the coal burned in its plants. PLEXOS is used to produce an ESP forecast that GenOps uses to produce an economic dispatch schedule that fully considers emissions. To this end, PLEXOS is run at least quarterly and additionally as needed, depending on changes in fuel prices and system conditions, to produce a week-ahead ESP forecast for GenOps to produce a day-ahead dispatch forecast.[6]

The process for estimating the ESP was first implemented by NSPI's Portfolio Optimization Group in 2016. An internal audit, conducted in the spring of 2016, made recommendations to improve the process of preparing and validating the inputs for PLEXOS and to improve the procedural documentation to encompass the entire ESP process. Management acknowledged the audit findings and committed to providing an action plan to adopt the recommendation by April 15, 2016.[7] Our independent review of NSPI's documentation of its PLEXOS parameters—which we detail below—concluded that NSPI had not fully implemented a system of inputs preparation and validation. Our recommendation at the end of this chapter regarding this issue reiterates the need for better PLEXOS inputs and assumption documentation.

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[6] NSPI, Emission Shadow Pricing Process Audit, March 2016, page 2.

[7] NSPI, Emission Shadow Pricing Process Audit, March 2016, page 5.

III.B.2.c. PLEXOS Input Information Origination and Maintenance

Appendix B of the FAM Plan of Administration documents the FAM Fuel Forecasting Methodology governing the process and assumptions used by NSPI to produce the fuel forecast required to set the Base Cost of Fuel. This document specifies the manner and sources of many of the parameters and assumptions used in PLEXOS; it also refers to the schedule to update the associated values. While the document points to Appendix D as providing the schedule for forecasting activities and information requirements related to FAM administration, an inspection of Appendix D does not show a detailed schedule regarding this process.[8]

Prior to 2013, NSPI used ABB's Strategist model to forecast the optimal operation of the generating fleet. As NSPI transitioned to PLEXOS to replace Strategist, NSPI created a report to document the "current" values of PLEXOS parameters, which did not appear in NSPI's Strategist Model, and how the values were established. The parameters in the document are to be updated on a periodic basis as provided by various NSPI subject matter experts or on demand due to observed and/or expected changes in system operation.

The Generation Asset Management (GAM) supplies all operating characteristics of generating units, including heat rates, forced outage rates, variable O&M costs, maximum capacities and expected wind hourly generation profiles. The Solid Fuels and Natural Gas & Oil Teams provide fuel prices and physical limits based on market availability and inventory/logistics constraints. The development of pricing assumptions follows the FAM Plan of Administration. Startup costs and times are provided to System Planning by the FERM group and are consistent with what is currently used in the GenOps day-ahead unit commitment and dispatch model.

Only relatively short duration outages—such as those included in the modeled DAFOR rate—are modeled in PLEXOS; major unplanned outages are excluded for modelling purposes, as they would otherwise have the potential to unduly influence simulation results. Ramp rates are maintained by FERM and should be consistent with what is currently modeled in GenOps. However, this does not appear to be the case, as discussed in the next section.

PLEXOS currently models five types of operating reserves for the NSPI system: Regulation Up, Regulation Down, Spinning, Ten-Minute Spin, and Ten-Minute Non-Spin—the last two with values pre- and post-Maritime Link. The total of Spinning and Ten-Minute Non-Spin reserves reflects NSPI's 171 MW operating reserve commitment to the Maritimes Region reserve requirement under Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC) operating guidelines. These requirements are provided by the NSPI system operator and are updated on an annual basis.

The minimum steam unit commitment parameters currently modeled in PLEXOS are set by the NS System Operator. The NSPI PLEXOS model also incorporates a dynamic requirement for Metro Dynamic

8 Fuel Manual Revision 10, Appendix B, FAM Fuel Forecasting Methodology, September 23, 2016.

Reactive Reserve, where the hourly reserve requirement in mega volt ampere reactive power (MVAR) is calculated based on Onslow South corridor flow and total system load. Linearized unit capability curves for the metro units (Tufts Cove and Burnside) are in the model to properly reflect the inverse relationship between unit dispatch level and available generator MVAR. The NSPI Transmission Planning group updates these Metro Dynamic Reactive Reserve requirements periodically the as system configurations change (e.g., capacitor bank modifications, transmission node configurations).[9]

The Director of Fuels and the Director of Portfolio Optimization are ultimately responsible for approval of all assumptions used in the production of the F&PP forecasts and the output of the forecasts. There is no outside vetting of the fuel supply model and assumptions by third-parties or stakeholders. The only exception is that assumptions related to COMFIT projects are provided by the Nova Scotia Department of Energy.

III.B.2.d. Input Parameter Validation

The following PLEXOS input parameters are subject to regular review within NSPI or are provided by the Nova Scotia System Operator:

- System Reserve Requirements
- Minimum Unit Commitment Constraints

The following PLEXOS input parameters are maintained by FERM and are updated in PLEXOS as needed to be consistent with the GenOps dispatch model:

- Unit Startup Costs
- Unit Ramp Rates

The following PLEXOS input parameters are model calibration values, set to achieve the model behavior that reflects the general fleet dispatch constraints under normal operation; NSPI will update them as those operating behaviors change in the future:

- Steam Unit Min Up / Down Times
- Forced Outage Repair Times

Since the PLEXOS Input Parameter Documentation from which the above parameter validation was reproduced was prepared in response to a prior audit recommendation, following the above parameter validation description, NSPI stated: "As the system modelling parameters identified in this document are either part of an existing update program, or are model calibration values representing general fleet dispatch constraints under normal operation, NSPI does not believe that a separate validation program for these parameters is required at this time." It may be time to reconsider this position, as the ramp rates

9 PLEXOS, like other production modelling tools relies on a DC approximation to save execution time when modelling the power flows in the transmission system, thus using a linearized equation to model the relationship between generating unit dispatch and available reactive power from the same unit.

used in PLEXOS were found to be inconsistent with those used in the GenOps dispatch model. This inconsistency and its possible impact on F&PP forecasting are discussed in the next paragraphs.

III.B.3. Accuracy of Fuel and Purchased Power Forecasting

Figure III-4. Comparison of Actual vs. Forecast Fuel Costs (2016, 2017)

	2016			2017		
Cost	Actual	Forecast	Variance (%)	Actual	Forecast	Variance
Solid Fuel	$ 237,275,351	$ 233,536,104	1.6%	$ 193,484,562	$ 190,815,154	1.4%
Natural Gas	$ 46,225,585	$ 41,639,639	11.0%	$ 64,379,881	$ 47,086,164	36.7%
Biomass	$ 11,067,868	$ 24,778,436	-55.3%	$ 5,890,577	$ 3,372,921	74.6%
Bunker C	$ 16,782,836	$ 11,255,090	49.1%	$ 4,584,347	$ 21,645,134	-78.8%
Diesel	$ 994,541	$ 571,781	73.9%	$ 1,851,725	$ 421,959	338.8%
Furnace	$ 2,431,406	$ 2,035,098	19.5%	$ 2,213,602	$ 1,468,966	50.7%
All Fuels	**$ 314,777,587**	**$ 313,816,148**	**0.3%**	**$ 272,404,694**	**$ 264,810,298**	**2.9%**

Figure III-4 above shows observed variances between NSPI's actual FAM costs from its forecast FAM costs, by fuel, over the two year Audit Period. In 2016, the overall variance was just 0.3%, while in 2017, the variance was still a low 2.9%. These variances are positive, but it is important to point out that the low variances may mainly be the result of NSPI "managing" actual fuel expenditures to budget. We note, for example, Figure III-4's much higher variances across the individual fuels, and more to the point, the significant variances in the predicted versus actual output of individual generating facilities, which is shown in Figure III-5 below.

Figure III-5. Comparison of Forecast vs. Actual Budgets by Generating Facility

	2016				2017			
	Actual	Budget	Difference	Variance (%)	Actual	Budget	Difference	Variance
Lingan	[redacted]							
Tufts Cove								
Trenton								
Point Tupper								
Point Aconi								
Combustion Turbines								
LM6000								
Renewables								
Total Generation (MWh)								
Purchased Power								
Imports								
IPP								
Wind								
COMFIT								
Total Purchases								
Total MWhs Available								
Domestic Revenue								
Exports								
Total Electric Revenue								
Line and Other Losses								
Export Percentage of Total MWhs								

III.B.4. Liberty's 2014–2015 Recommendations

The previous fuel auditor had two recommendations in its most recent audit report. First, Liberty recommended that "NSPI should develop and implement a disciplined program of back-casting generation forecasts."[10] NSPI agreed with this recommendation.[11] In response to Liberty's recommendation, NSPI completed a back-cast of the total system fuel and purchased power cost with PLEXOS and reported the results in September 2017.[12] We find that NSPI appropriately responded to this

[10] Liberty 2014-2015 Audit Report, page II-17.

[11] NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 11.

[12] NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 11.

Liberty recommendation. We also note that the back-cast analysis was worth recounting, which we do here.

The purpose of the back-cast analysis was to compare the optimized system dispatch by PLEXOS to actual system outcomes, and to use the results as a means of model validation and identification of system dispatch adjustments.

The back-cast process was handled by GAM and FERM in a two-stage process. The GAM department set up the initial system back-cast model based on the system dispatch optimization model of record. The initial model was populated with actual 2016 fleet performance data, including forced and planned outages, generating unit de-ratings, wind and run-of-river hydro generation hourly output, hourly system demand, transmissions system constraints, and other system parameters. The partial system model was handed over to the FERM team to handle the next steps.

The FERM department updated the system model with actual commodity prices as they were known at the time of dispatch. The model was subsequently debugged and executed. Several system assumptions were made with respect to several factors: import energy availability, energy and REC exports, and Port Hawkesbury Biomass (PHB) generating unit utilization with respect to the PHP arrangements.

The back-cast of the NSPI generation 2016 fleet dispatch using actual system performance figures, together with realized fuel and purchased power prices, yielded a total system fuel and purchased power cost difference of 0.61% of actual fuel and import power costs, including the cost of mercury (Hg) abatement.

The model back-cast shows a different system dispatch pattern from the actual, but the realized total system dispatch cost is very similar to that of the actual 2016 system dispatch. This is to be expected, as the PLEXOS dispatch cannot always be replicated by NSPI under real operating conditions. As NSPI observes in the back-cast report, "PLEXOS makes unit commitment and dispatch decisions based on very minor differences in dispatch cost, and without regard to system condition, weather, and other subtleties of real time dispatch that are beyond the scope of computer simulation."[13] Thus, the results of the back-cast can only validate the ability of PLEXOS to set an optimum dispatch cost as a target for NSPI's system operators.[14]

One notable finding of the back-cast exercise was the model-to-actual variance in the operation of the Tufts Cove combined cycle units, where the back-cast model showed a decrease in cycling and increased output compared to what actually took place in 2016. It appears that the PLEXOS model chose to run the combined cycle unit more as a base loaded than a flexible unit. One possible explanation of this variance may be found in the ramp values used in PLEXOS, which were specified in the model to be as low as those of NSPI's coal-fired steam facilities, as shown in the following table. Given the lower heat rate of

[13] Nova Scotia Power 2016 Backcast Report, September 2017, page 8.

[14] Nova Scotia Power 2016 Backcast Report, September 2017, page 8.

the combined cycle facility and its erroneously specified slow ramping ability, PLEXOS chose to dispatch it ahead of other less efficient units, resulting in less cycling and a baseload-like operation.

Figure III-6. Inconsistency in NSPI's Thermal Generating Unit Ramp Rates

Thermal Plant	PLEXOS Ramp Rate (MW/Minute)	GenOps Ramp Rate (MW/Minute)
Tufts Cove 4	2.00	5.00
Tufts Cove 5	2.00	5.00
Tufts Cove 6	2.00	3.50
Trenton 6	2.00	2.00
Lingan 1	2.00	2.00
Lingan 2	2.00	2.00
Lingan 3	2.00	2.00
Lingan 4	2.00	2.00
Point Tupper	2.00	2.00
Tufts Cove 2	2.00	2.00
Tufts Cove 3	2.00	2.00
Trenton 5	1.75	1.75
Point Aconi	1.00	1.00
Tufts Cove 1	1.00	1.00

The small variance between the total fuel cost predicted by PLEXOS and the actual costs also suggests that NSPI has enough system flexibility with respect to generating unit interchangeability, solid fuel blending, Hg abatement, natural gas/HFO fuel switching capability, and flexible quick-start generation and hydro resources to accommodate a vast number of resource dispatch combinations to ultimately lead to optimum fuel cost results similar to the optimal dispatch forecast by PLEXOS.

Liberty's second recommendation was that "[NSPI] should add updating schedules and processes to the documentation program for [PLEXOS] parameters."[15] NSPI agreed with this recommendation,[16] noting that it now carries out weekly and monthly system access testing, as well as an annual review. We find that NSPI addressed Liberty's recommendation; however, as we note elsewhere, NSPI's documentation processes could be further improved, and we include a conclusion and recommendation below to that effect.

III.C. Conclusions

Conclusion III-1: The 2017 energy sales forecasting methodologies, models, and data are reasonably accurate.

Conclusion III-2: NSPI's 2017 peak demand model is reasonable, but not as robust as the predominantly end-use-driven residential and small/medium commercial energy forecast models. The large year-to-year

15 Liberty 2014-2015 Audit Report, page II-17.

16 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 11.

variability of NSPI's peak system demand suggests exercising caution in making long-term decisions based on a single-year peak demand forecast.

Conclusion III-3: The PLEXOS model is well suited to simulating the future economic dispatch of NSPI's generating fleet subject to transmission security and environmental constraints.

Conclusion III-4: The three-year rolling average wind production histories my not be fully representative of the long-term variability of wind speeds and their effect on wind energy production.

Conclusion III-5: The PLEXOS Input Parameter Documentation is currently updated once a year, although changes appear to be made to the model inputs for quarterly F&PP runs and occasionally more frequent ESP runs. The inconsistencies in PLEXOS input assumptions and the inability to attribute differences in in model outputs to changes in input values and assumptions highlight the need for better documentation practices.

Conclusion III-6: The peak load forecast model in its current form largely depends on historical relationships but fails to provide much predictive power for changing demand driven by the adoption of new technology, nor for the impact of increased levels of demand response.

III.D. Recommendations

Recommendation III-1: NSPI should maintain documentation describing the type and number of large customers surveyed each year, the survey response rate, and the results of the large customer survey and other market research used in forecasting load for large customers.

Recommendation III-2: NSPI should expand the documentation on PLEXOS inputs from the current document on the inputs not required by Strategist to a comprehensive description of all inputs and assumptions used in running PLEXOS for the various dispatch horizons (annual, quarterly, and weekly ESP runs). This document should address recommendations made by the internal ESP process audit, to the extent not already done, and be updated quarterly; records of any changes made to inputs during the weekly ESP runs should be kept.

Recommendation III-3: NSPI should provide consistency between the generating unit characteristics used in PLEXOS and those used in GenOps.

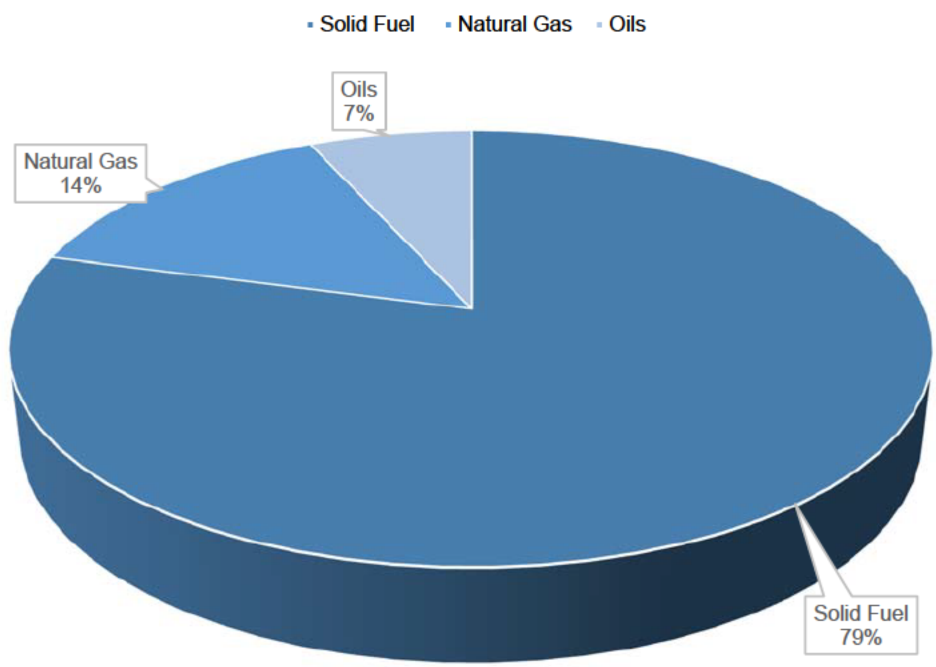
Recommendation III-4: NSPI should study the long-term variability of wind and incorporate that variability, if any, to the modelling of the wind resource in the ten-year PLEXOS modelling of optimal production cost.

IV. Solid Fuel Procurement and Contracts

IV.A. Background

Solid fuel—i.e., coal, petcoke, and biomass fuel—has historically been NSPI's largest fuel expense. The same was true in this Audit Period. Figure IV-1 and Figure IV-2 show that for both 2016 and 2017, solid fuel accounted for 79% and 73%, respectively, of all NSPI's expenses for fuel purchases that are burned for the purposes of generating electricity.[1]

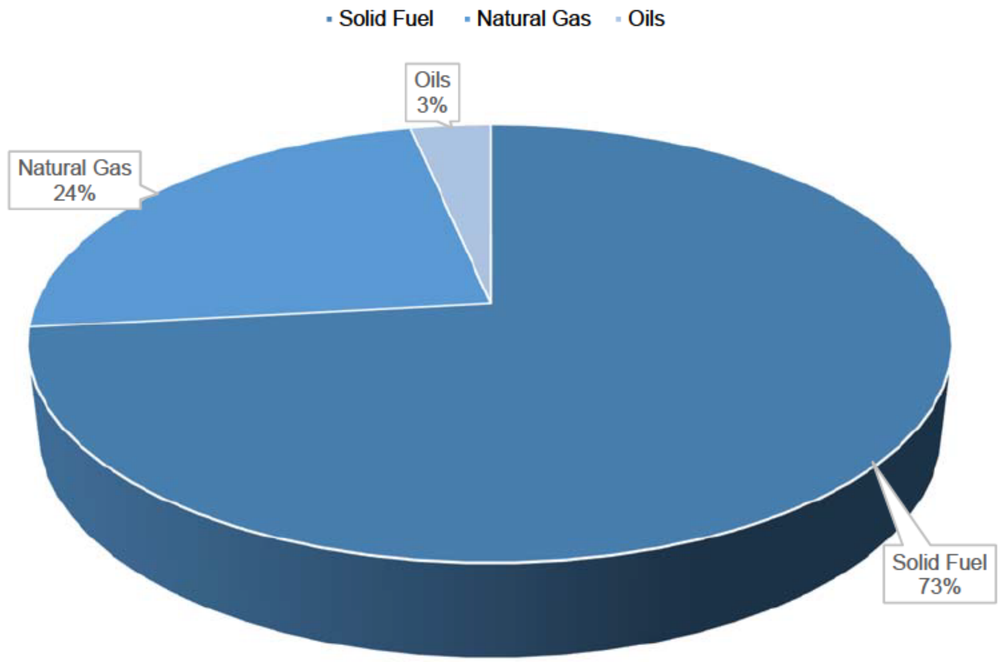
Figure IV-1. Percentages of Total Fuel Expense among Three Major Categories of NSPI's Fuel (2016)[2]



[1] Figures IV-1 and IV-2 do not include other FAM expenses, such as those for purchased power, additives (e.g., powder-activated carbon), etc.

[2] NSPI 2017 Annual FAM Report, A-3. Solid fuel includes coal, petcoke, and biomass. Oils include diesel, bunker C, and furnace oil.

Figure IV-2. Percentages of Total Fuel Expense among Three Major Categories of NSPI's Fuel (2017)[3]



In this chapter, we review and assess NSPI's procurement of solid fuel. We begin by explaining NSPI's solid fuel-fired fleet, including which type of solid fuel each uses. Next, we look at NSPI's consumption of solid fuel during the Audit Period—that is, the amount of solid fuel burned for the purpose of generating electricity. We look at these data by plant, across solid fuel types, and in comparison with forecasts. We then explain the sources and types of NSPI's solid fuel. Next, we discuss the prices NSPI paid for solid fuel during the Audit Period. We then summarize NSPI's master supply contracts for solid fuel and all existing NSPI supply arrangements entering the Audit Period. We then review new supply arrangements for solid fuel executed during the Audit Period. Next, we provide our assessment of NSPI's solid fuel procurement process. We then review all contract actions taken by NSPI during the Audit Period (e.g., amendments, litigation, force majeure). We next assess NSPI's procurement of solid fuel-related goods and services, such as marine and rail transportation, as well as calcium chloride and powder activated carbon. We conclude with a discussion of environmental regulations applicable to NSPI's solid fuel-fired fleet.

3 NSPI 2017 Annual FAM Report, A-3. Solid fuel includes coal, petcoke, and biomass. Oils include diesel, bunker C, and furnace oil.

IV.B. Findings

IV.B.1. NSPI's Solid Fuel-Fired Fleet

Nine of NSPI's generating units—representing 1,277 MW of capacity—burn solid fuel as their primary fuel. The vast majority of that amount is fired by coal—only Port Hawkesbury (biomass) and Point Aconi (petcoke) burn something other than coal as their primary solid fuel. Figure IV-3 shows NSPI's solid fuel-fired fleet. Note that other than Trenton 5, which burns only coal, and Port Hawkesbury, which burns only biomass fuel, all of NSPI's solid-fuel fired fleet burn a combination of coal and petcoke. There are, of course, several types of coal—we provide data on NSPI's use of particular types of coal below.

Figure IV-3. NSPI's Solid Fuel-Fired Fleet

Power Plant	Nameplate Capacity (MW)	Primary Solid Fuel	Other Solid Fuels
Lingan 1	153	[redacted]	
Lingan 2	153		
Lingan 3	153		
Lingan 4	153		
Point Aconi	168		
Point Tupper	150		
Port Hawkesbury	43		
Trenton 5	150		
Trenton 6	154		
Total	**1,277**		

IV.B.2. Solid Fuel Consumption

NSPI consumed a total of [redacted] metric tons of solid fuel (ignoring biomass) in the Audit Period. This was about 2.2% below forecasted consumption of [redacted] metric tons. As we explain below, the lower solid fuel consumption was driven largely by higher-than-expected solid fuel prices. NSPI also consumed [redacted] green metric tons of biomass fuel, which was about 54.1% below forecasted consumption of [redacted] green metric tons. Also as we explain below, this result was primarily attributable to the change in status of the Port Hawkesbury biomass unit from must-run status to economic. Figure IV-4 provides these data in more detail, as broken down between 2016 and 2017.

Figure IV-4. NSPI's Solid Fuel Consumption vs. Forecast (2016, 2017)

	2016			2017		
Solid Fuel Type	Consumption (MT)	Forecast (MT)	Comparison	Consumption (MT)	Forecast (MT)	Comparison (%)
Solid Fuel	[redacted]					
Biomass						
Total						

Digging deeper on non-biomass solid fuel, Figure IV-5 shows that in 2016, NSPI actually consumed more solid fuel than forecasted in most months; however, due to significantly lower-than-forecasted consumption in the first three months of the year, overall consumption was lower than forecast for the year. In 2017, there were mixed results, with about an even split between over-estimated months and under-estimated months; overall, again, consumption was slightly below forecast. NSPI's forecast tracked reasonably well, exhibiting a correlation of 0.779 for the entire Audit Period.

Figure IV-5. NSPI's Month-by-Month Non-Biomass Solid Fuel Consumption vs. Forecast (Metric Tonnes)

[redacted]

IV.B.3. **Solid Fuel Sources and Types**

NSPI's thermal generators do not burn one single type of solid fuel. Rather, NSPI uses blends of solid fuel at each of its solid fuel-fired generating units. These blends can include various types of coal and petcoke. The coal comes from a combination of domestic sources, such as the Stellarton Mine or the Donkin Mine, or can be imported from the United States or South America. (We explain below NSPI's approach to blending fuels and the relative benefits of each type of solid fuel.) Petcoke is imported from the United States. Figure IV-6 shows, by month, NSPI's solid fuel consumption of petcoke, imported coal, and domestic coal. Notably, imported coal represents the vast majority of solid fuel consumption. Over the two-year Audit Period, NSPI's solid fuel mix was [redacted] imported coal, [redacted] petcoke, and [redacted] domestic coal.

Figure IV-6. NSPI's Monthly Solid Fuel Consumption (Metric Tonnes) (by general solid fuel type)

[redacted]

Besides showing the relative percentages of imported coal, domestic coal, and petcoke, Figure IV-6 also shows the large uptick in solid fuel consumption during the winter months. One way to illustrate the seasonality of NSPI's solid fuel consumption is to compare the lowest and highest consumption months for the year. For example, in 2016, NSPI burned just [redacted] MTs of combined coal and petcoke in September 2016, while in December 2016, NSPI burned [redacted] MT—an increase of 78.7%. In 2017, the results were even more extreme: NSPI burned [redacted] metric tons of coal and petcoke in its highest consumption month (January), which was 132.5% higher than its lowest consumption month (October: [redacted] metric tonnes (MTs)).

Looking more closely at the specific types of coal being burned, we note that coal types can vary in important ways, such as sulphur content, Btu content, and ash content. Lower sulphur coal helps NSPI meet its emissions limitations, such as its SO_2 and mercury limits. Btu content determines the energy potential of the coal; the higher the Btu content, the more efficient that coal will be in generating electricity. Ash content is a measure of how much ash is produced by burning the coal; higher ash content coal is more challenging to manage than low-ash coal. Each plant has a "staple fuel" that is the core fuel primarily used at a given unit to support reliable operation; each plant also uses "adder fuels," which are generally inferior fuels blended in with the staple fuels to reduce the overall cost of fuel for FAM customers. During the Audit Period, NSPI consumed the following types of coal:

- Low-sulphur, high Btu Colombian coal (import)[4]—Sourced in northeastern Colombia and delivered by marine vessel, this coal helps NSPI meet its emissions limitations due to its low sulphur content.

- Low-sulphur, low Btu Colombian coal (import)[5]—This coal is similar to the low-sulphur coal above but has a lower Btu content—and thus commands a lower price.

- Mid-sulphur US Northern Appalachian coal (import)[6]—This coal is shipped by marine vessel from the United States and is a lower-cost coal than the Colombian coal. It is sourced in the Northern Appalachian region, which includes portions of Pennsylvania, Ohio, Maryland, and West Virginia.

- Powder River Basin (PRB) coal (import)—PRB coal is low-sulphur, low Btu coal found in Wyoming and Montana. NSPI had historically used PRB in Lingan's blend, but PRB was removed from Lingan's blend in November 2016. PRB was also used in Point Tupper's blend but was removed in September 2017.[7]

- [redacted] coal (domestic)[8]—This coal is a high ash content coal that is not optimal for consumption at most of NSPI's generating fleet. Trenton 6 is the only unit that burns [redacted] coal; this unit was specially designed to accommodate the high ash content of this coal and [redacted]

- [redacted] coal (domestic)[9]—[redacted] As we explain in detail below, NSPI purchased small quantities of [redacted] coal in 2017 for consumption at the Lingan plant, [redacted]

- Petcoke (import)[10]—Petroleum coke, or "petcoke," is a [redacted]. A byproduct of oil refining operations, petcoke is sourced from refineries in the United States, either in the Great Lakes region or the Gulf Coast. Petcoke typically has a higher sulphur content than coals, as well as a higher Btu content—overall, petcoke typically costs less

4 This coal typically has a Btu/lb content of greater than 11,600, a sulphur content of less than 1%, and a mercury content of less than 0.08 ppm.

5 This coal typically has a Btu/lb content between 10,800 and 11,300, a sulphur content of less than 1%; and a mercury content of less than 0.08 ppm.

6 This coal typically has a Btu/lb content of about 12,900, a sulphur content of 3%, and a mercury content between 0.08 and 0.16 ppm.

7 NSPI's PRB sources typically have a Btu/lb content of 9,350 and a Sulphur content of less than 0.5%.

8 This coal typically has a Btu/lb content of about 10,600, a sulphur content of about 1.6%, and a mercury content of about 0.07 ppm.

9 This coal typically has a Btu/lb content of about 13,700, a sulphur content of about 2.3%, and a mercury content of about 0.12 ppm.

10 NSPI's petcoke typically has a Btu/lb content of about 14,000, a sulphur content of about 6%, and a mercury content between 0.01 and 0.02 ppm.

than coal. Petcoke is burned in high amounts at Point Aconi, which has fluidized bed technology designed to burn petcoke as its primary fuel; other thermal plants, including Lingan, Trenton 6, and Point Tupper, burn petcoke to enhance the Btu content and to improve particulate emission control performance by increasing sulphur and lowering the ash content of the overall fuel blend.

Figure IV-7 shows the total amount of each type of solid fuels used by NSPI across the entire fleet. Note that [redacted] is the staple fuel at each of the Lingan units, as well as at Point Tupper and Trenton 5. [redacted] is an adder fuel at all plants except Trenton 5, [redacted] coal is the staple fuel at Trenton 6.

Figure IV-7. NSPI's Coal, Petcoke Consumption by Plant

Power Plant	LSH	LSL	MS	PRB	Stellarton	Donkin	Petcoke
Lingan 1	[redacted]						
Lingan 2	[redacted]						
Lingan 3	[redacted]						
Lingan 4	[redacted]						
Point Aconi	[redacted]						
Point Tupper	[redacted]						
Trenton 5	[redacted]						
Trenton 6	[redacted]						
Total	[redacted]						

Figure IV-8 shows the breakdown of solid fuel use at each unit for the Audit Period. The figure also shows the overall consumption of solid fuel at each plant to provide perspective on the relative consumption at each plant. Collectively, the four-unit Lingan plant consumes the most solid fuel; on a per-unit basis, Point Aconi and Trenton 6 led the fleet in consumption over the Audit Period.

Figure IV-8. NSPI's Solid Fuel Consumption by Plant, Source (Metric Tonnes)

[redacted]

There are two trends worth drawing out in terms of NSPI's coal consumption in 2017 compared with its consumption in 2016. The first involves the Lingan units, which saw the introduction of domestic [redacted] coal into their fuel blends in 2017 and which [redacted] use of [redacted] coal. Figure IV-9 below shows solid fuel consumption at Lingan over the two-year Audit Period.

Figure IV-9. Solid Fuel Consumption Breakdown at Lingan Units 1–4 (2016 vs. 2017)

[redacted]

[redacted]

The second trend is at Trenton 6, which has seen [redacted] coal in its fuel blend. Note that historically, including in 2016, [redacted] coal made up about [redacted]% of the fuel blend; in 2017, that amount [redacted] to [redacted]% and is forecasted to [redacted] going forward—NSPI is planning on using [redacted]% [redacted] coal for the coming period. NSPI explained that the reason for this reduction is the fact that the [redacted]

11 Bates White's analysis referenced in this paragraph compared the fourth quarter 2017 [redacted] contract's typical specifications and delivered price with that of the April 2017 [redacted] contract, the 2016 [redacted] option ROA, the Fuel Manual's technical specifications for mid-sulphur coal and petcoke, and three mid-sulphur contracts: [redacted] (August 2016), [redacted] (August 2016), and [redacted] (September 2017).

[redacted] Thus, beginning in [redacted], Trenton 6 is forecast to consume [redacted], a fact that has been reflected in NSPI's Plexos forecasts. Given that the [redacted] coal it consumes at Trenton 6. NSPI worked with [redacted]

Moreover, NSPI has been [redacted] coal supply and the impact of operating Trenton 6 on [redacted]. We observed that NSPI's consideration of railcar leases and rail transportation services for shipments of coal has appropriately assessed the potential increase in [redacted]—and thus, rail transport—for Trenton 6, as [redacted] coal supply dwindles. NSPI also commissioned a study by [redacted] to review the impact of reliance on [redacted] coal for Trenton 6 as it relates to the solid fuel handling capabilities of the Point Tupper Marine Terminal (where Trenton's imported solid fuel arrives by marine vessel) and Trenton. (We summarize this study in our Solid Fuel Supply Management chapter.)

Going forward, as less [redacted] coal is burned at the Trenton 6 unit, the performance metrics at Trenton 6 should be monitored closely, since, as noted above, the Trenton 6 unit was specially designed to burn the [redacted]. Moreover, it would be expected that the cost of fuel at Trenton 6 would [redacted]

Figure IV-10. Solid Fuel Consumption Breakdown at Trenton 6 (2016 vs. 2017)

[redacted]

Turning from coal and petcoke to biomass, the Port Hawkesbury biomass unit consumes two types of biomass fuel: primary biomass, which consists of wood chips or roundwood, and secondary biomass, which consists of bark. Wood chips and roundwood are of higher quality due to their higher Btu content which is a result of their lower moisture content; moreover, because bark is a byproduct of the pulpwood and saw log production process while wood chips require harvesting and chipping, bark is a lower cost fuel than woodchips. These two fuels are blended throughout the year. As shown above in Figure IV-4, NSPI consumed far less biomass fuel in 2016 than forecasted due to the biomass plant losing its "must-run" status during 2016. Instead, NSPI dispatched the biomass plant economically, leading to a large reduction in its usage and consumption of fuel. In 2017, the biomass unit again consumed far less fuel than during its days as a must-run unit but exceeded forecasts due to its favorable economics and provided additional environmental value as NSPI approached its fleetwide limitations on annual emissions. (Note that the biomass unit is considered emissions-free from an environmental perspective when run on biomass fuel.)

IV.B.4. Solid Fuel Prices

Coal prices during the Audit Period exhibited unexpected strength, especially starting in the summer of 2016. Some common coal-price indices—[redacted]—more than doubled between their low point in the first months of 2016 and their high point in the winter of 2017.[12] This market-wide change in prices had a significant impact on NSPI, as its forecasted solid fuel prices were below the actual prices during the Audit Period. In fact, NSPI's price forecast was below actual in 21 of 24 months in the Audit Period; nevertheless, NSPI's forecasts exhibited a correlation of about 0.83 with actual observed prices. We note that this strong correlation was a positive result for NSPI's forecasting, as the coal price rally that began in 2016 and stretched into 2017 has been described as "sudden," "unprecedented," and "sharp," with both Goldman Sachs and Citigroup describing coal as the "hot commodity" of 2016.[13] In the latter half of 2017, coal prices fell, resuming their longer-term downward trend. Figure IV-11 provides a month-by-month look at NSPI's non-biomass solid fuel prices—forecasted versus actual—for the Audit Period.

[12] See, e.g., Quandl, "Coal (API2) CIF ARA (ARGUS-McCloskey) Futures, Continuous Contract #2 (MTF)," available at: https://www.quandl.com/data/CHRIS/CME_MTF2-Coal-API2-CIF-ARA-ARGUS-McCloskey-Futures-Continuous-Contract-2-MTF2.

[13] Reuters, "Coal Price Rally Comes to the Rescue of Commodity Trading Giants," October 30, 2016, *available at* https://www reuters.com/article/us-coal-price-winners-idUSKBN12V011.

Figure IV-11. Non-Biomass Solid Fuel Prices ($/Tonne) (Forecasted vs. Actual, by month)

[redacted]

Looking more granularly at non-biomass solid fuel prices, Figure IV-9 compares the month-by-month actual prices of imported coal, domestic coal, and petcoke. As is shown in the figure, [redacted]

14 2014–2015 Liberty Audit Report, page IV-5.

Figure IV-12. Imported Coal, Domestic Coal, and Petcoke Prices ($/Tonne)

[redacted]

Figure IV-13 provides a breakdown across the two-year Audit Period of the total solid fuel costs across NSPI's non-biomass, solid fuel-fired fleet. Point Aconi, which uses about [redacted] as its [redacted] fuel, saw the [redacted], while Trenton 6—which uses domestic [redacted] coal as its staple fuel—had the [redacted] Point Tupper, Trenton 5, and the Lingan units, [redacted]

Figure IV-13. Solid Fuel Prices by Plant ($/Tonne)

Power Plant	2016	2017
Point Aconi	[redacted]	[redacted]
Trenton 6	[redacted]	[redacted]
Point Tupper	[redacted]	[redacted]
Trenton 5	[redacted]	[redacted]
Lingan	[redacted]	[redacted]

Biomass fuel averaged [redacted]/green metric ton in 2016 and [redacted]/green metric ton in 2017. This price decrease was driven by use of lower cost blends of biomass fuel—i.e., using more bark and less wood chips—[redacted].

Figure IV-14. Biomass Prices ($/Green Metric Ton) (Actual vs. Forecast)

	2016		2017	
Solid Fuel Type	Actual	Forecast	Actual	Forecast
Biomass	[redacted]			

IV.B.5. NSPI's Master Supply Contracts for Solid Fuel

Entering the Audit Period, NSPI had several existing "master" supply agreements already in place for solid fuel. These master agreements—similar in scope to International Swaps and Derivatives (ISDA) or North American Energy Standards Board (NAESB) agreements for natural gas, power, or hedging transactions—help reduce the time and cost of buying solid fuel by codifying a set of agreed-upon terms and conditions of supply that does not change or require renegotiation for each solid fuel shipment. These master agreements tend to be long-term agreements[15] that specify the terms by which the buying and selling parties will transact, including the quality specifications and references to the applicable American Society for Testing and Materials (ASTM) standards. The agreements also specify how the fuel will be weighed and tested and how the price will be adjusted if weight and/or quality do not meet specifications. Over the life of that master agreement, the parties will enter into shorter-term agreements, called "confirmations," which specify the amount of solid fuel that NSPI will buy over that period, the price, the quality, the period in which NSPI can specify delivery, and various other information that is specific to that short-term agreement. In this section, we provide details on the master supply agreements; in the next section, we address the confirmation agreements.

At the beginning of the Audit Period, NSPI had in place [redacted] master agreements in place for coal, [redacted] for petcoke, and [redacted] for biomass. Figure IV-15 summarizes NSPI's existing master contracts for solid fuel supply as of January 1, 2016.

15 Typically, the master agreements do not specify a termination date; rather, the contract allows either party to terminate the contract under certain conditions.

Figure IV-15. NSPI Master Fuel Supply Contracts (as of January 1, 2016)[16]

Supplier	Product	Type of Agreement	Year Executed
[redacted]		Master Supply	2005
		Master Supply	2006
		Master Supply	2015
		Master Supply	2002
		Master Supply	2015
		Master Supply	2011
		Master Supply	2010
		Master Supply	2013
		Master Supply	2014
		Master Supply	2014

During the Audit Period, NSPI entered into [redacted] Specifically, on February 24, 2016, NSPI executed [redacted] with [redacted] for a [redacted] supply ([redacted] of coal. [redacted] Under the new agreement, NSPI has the option to buy delivered coal from [redacted] for [redacted] to the Lingan plant. There is no minimum quantity for NSPI to purchase under the contract.

In addition to these solid fuel supply arrangements, NSPI also had in place other agreements. One such set of agreements required sales of solid fuel to certain counterparties. One of those agreements is with [redacted] executed in October 2014, which requires NSPI to sell a [redacted] supply of coal to [redacted] A similar agreement, executed in December 2012, was in place with [redacted] We reviewed the terms and pricing under these contracts and found nothing unreasonable; we also understand that the impetuses for these contracts predates our Audit Period.

Lastly, NSPI had in place an agreement with [redacted] for assistance in developing an annual silviculture plan, which is part of NSPI's legislative requirements in buying biomass fuel for the Port Hawkesbury plant.

IV.B.6. NSPI's Existing Supply Arrangements Entering the Audit Period

While master agreements allow for the transacting of solid fuel supply, NSPI must enter into confirmation agreements with counterparties to specify short-term supply deliveries. Entering the Audit

[16] Note that the [redacted], which calls for purchases [redacted], is atypical in that it does not contain the same level of detailed terms and conditions found in the other Master Agreements for coal.

Period, NSPI had many supply arrangements already in place. These are summarized below in Figure IV-16.

Figure IV-16. NSPI Existing Solid Fuel Supply Arrangements (as of January 1, 2016)

		Total Contract Quantity		
Supplier	Product	2016	2017	2018
[redacted]				

IV.B.7. New Supply Agreements during the Audit Period, by Quarter

During the Audit Period, NSPI entered into several new contracts for solid fuel supply. We reviewed each of these contracts and the process by which those contracts were executed—this includes how winning suppliers were selected and why NSPI sought additional supply. In all cases, we found that NSPI's solid fuel procurement practices were prudent and based on reasonable decision making, given the information it had at the time. The processes used were in compliance with the Fuel Manual.

Below, we provide a summary of all new contracts signed over the two-year Audit Period, by quarter. We include both a table for each quarter showing the new contracts signed and a short summary of the contracts themselves.

IV.B.7.a. First Quarter 2016

NSPI entered into [redacted] for solid fuel supply in the first quarter of 2016. This contract is shown in Figure IV-17.

Figure IV-17. NSPI New Solid Fuel Supply Contracts (Q1 2016)

Supplier	Product	Quantity	Term
[redacted]	Coal	[redacted]	2016

As noted above, this sole new contract with [redacted] was for a [redacted] supply ([redacted]) of coal. Under the new agreement, NSPI has the option to buy delivered coal from [redacted] for [redacted] to the Lingan plant. [redacted]. NSPI explained that this purchase came about due to an [redacted]; from NSPI's point of view, this purchase helped augment portfolio requirements. We note that the price—which included delivery to Lingan—was reasonable for [redacted]

IV.B.7.b. Second Quarter 2016

NSPI entered into one new contract for solid fuel supply in the second quarter of 2016. This contract is shown in Figure IV-18.

Figure IV-18. NSPI New Solid Fuel Supply Contracts (Q2 2016)

Supplier	Product	Quantity	Term
[redacted]	Petcoke	[redacted]	[redacted]

On April 1, 2016, NSPI entered into a new confirmation agreement with [redacted] for the delivery of [redacted] of petcoke per year for a [redacted] term beginning in 2017. The agreement has a [redacted]. Pricing for this contract was favorable, ranging between [redacted] on a delivered basis. This contract was the product of a [redacted]; the response from bidders was robust, with [redacted] suppliers submitting offers. [redacted] was [redacted] the lowest priced offer. Moreover, NSPI forecasted that this transaction would [redacted], compared to the BCF if NSPI purchased the full quantities of available petcoke over the term of the contract. NSPI also showed that this purchase would [redacted] increase its physical solid fuel hedged position for [redacted] of the Rate Stability Period—a particularly useful point, given that hedging petcoke is impractical on a financial basis.

IV.B.7.c. Third Quarter 2016

NSPI entered into [redacted] contracts for solid fuel supply in the third quarter of 2016. These are shown in Figure IV-19.

Figure IV-19. NSPI New Solid Fuel Supply Contracts (Q3 2016)

Supplier	Product	Quantity	Term
[redacted]			

All [redacted] new solid fuel supply contracts were the product of competitive RFPs; [redacted] were winners in a single competitive RFP for low-sulphur coal, which was issued to NSPI's full supplier list of 92 potential counterparties. The RFP sought LSH product in 2016 (won by [redacted]) as well as a three-year term from 2017 to 2019 (won by [redacted]. The RFP also sought a smaller amount of LSL for the same three-year term (won by [redacted]).

The [redacted] offer—which [redacted] (approximately [redacted] metric tons per year)—was the product of a competitive RFP in which NSPI entered into negotiations [redacted] which offered a deal similar to [redacted], and then with [redacted]. During negotiations, [redacted] was willing to revise its offer more favorably than [redacted], including offering a [redacted]—a significant concession given the FST's concern about [redacted]. [redacted] offer was the best offer, however, for the [redacted] of the LSH RFP.

The winning [redacted] offer was also the subject of significant post-bid negotiations, as it was quite close to that of [redacted] (which also offered a LSL product). [redacted] ultimately was determined to have the best offer due to [redacted], as well as a [redacted] that lowered the overall cost. [redacted], meanwhile, would not make similar concessions in its post-bid negotiations.

The other [redacted] contracts were winners in a mid-sulphur coal RFP issued in June 2016. [redacted] (cheapest) and [redacted] (second cheapest) submitted the best offers, which saw responses from [redacted] bidders. Notably, offers received in this RFP were compared to [redacted] coal, both in terms of price and quality. During this time, NSPI was in negotiations with [redacted] for supply from [redacted] for 2017 and considered holding open some room to buy and consume [redacted] coal in 2017 (which it ultimately decided to do); NSPI's analysis of these RFP offers noted that the [redacted]," but that "[t]he upside value of consuming [redacted] of [redacted] in 2017 equals [redacted] versus the next best alternative [redacted]" NSPI assessed the risk of the market price for mid-sulphur coal to move substantially higher in the near term—should [redacted] coal not precipitate—to be "minimal." [redacted]; thus, NSPI decided to continue negotiating, while keeping open room in its portfolio for [redacted] coal instead of securing more mid-sulphur coal. Testing of [redacted] coal, which would confirm the quality of that coal, was scheduled to occur at that point by October 2016. We know now that the [redacted], but at the time, NSPI management could not have known that fact. This, combined with its assessment of the risk of higher mid-sulphur coal prices in the near term, led us to assess NSPI's decision to forgo additional mid-sulphur coal pursuant to this RFP to be reasonable.

IV.B.7.d. Fourth Quarter 2016

NSPI entered into [redacted] new contracts for solid fuel supply in the fourth quarter of 2016. These are shown in Figure IV-20.

Figure IV-20. NSPI New Solid Fuel Supply Contracts (Q4 2016)

Supplier	Product	Quantity	Term
[redacted]			

The [redacted] petcoke contract was selected pursuant to a competitive RFP held in September 2016, which sought petcoke supply for the fourth quarter of 2016 and/or the first quarter of 2017. The [redacted] offer was the best offer available, both in terms of cost and risk, which included [redacted]. NSPI also assessed the risk of contracting with [redacted] and noted that [redacted], a highly-rated entity—provided a [redacted].

The [redacted] contract was not executed pursuant to an RFP, since in this case NSPI needed a [redacted] of a defined product—mid-sulphur coal—and had a limited amount of time to procure [redacted]. NSPI explained that in such instances, it may not issue an RFP but will instead seek bids directly from a shorter list of producers known to supply that specific coal. In this case, NSPI saw higher-than-forecasted consumption of solid fuel in the fourth quarter, including in December, when actual consumption exceeded forecast consumption by [redacted].[17] NSPI also explained that [redacted], creating a short-term need for mid-sulphur coal. Also, the [redacted]—which in the previous quarter had been contemplated as a replacement for mid-sulphur coal—[redacted],[18] though NSPI explained that its winter 2017 planning was not dependent on [redacted] coal.[19]

17 NSPI December 2016 FAM Report, M-7.

18 NSPI Q4 2016 FAM Report, Q-5.

19 NSPI Q4 2016 FAM Report, Q-5.

The Fuel Manual does not require NSPI to conduct RFPs in procuring new supplies of solid fuel; rather, the Fuel Manual notes that the RFP process "is but one of a suite of strategies to create a competitive environment," including "direct negotiations," which was the method employed in this case. Unlike with an RFP, the decision making that leads to contracts like this [redacted] contract is more difficult to assess. Management has less time to react, and the amount of documentation is reduced—in both cases, appropriately so. Nevertheless, we were able to confirm that the [redacted] contract represented prudent decision making by NSPI: NSPI did suffer a mid-sulphur coal supply disruption in the fourth quarter and was consuming solid fuel at a rate above its forecast; this showed a clear need for additional mid-sulphur supply. Moreover, the price secured—[redacted]—was consistent with the overall market at the time, as adjusted for transportation costs, especially given the short notice and [redacted] nature of the transaction. NSPI also received indicative offers from [redacted] suggesting a competitive result. Lastly, this approach to procurement is consistent with the NSPI Fuel Manual.

The contract with [redacted] for biomass fuel, which also included fuel yard handling services and fuel transport system operating and maintenance services, was a contract to provide standby biomass supply and was entered into pursuant to an RFP.[20] [redacted] suppliers were invited to bid; [redacted] expressed interest, and [redacted] actually bid: [redacted]. Importantly, NSPI conducted an evaluation of the provision of standby fuel supply on its own, separate from the other services sought in the RFP (e.g., fuel yard handling services). This meant that [redacted] bid—which was lower than [redacted]—had to compete on a level playing field. [redacted] bid was clearly lower than [redacted]

IV.B.7.e. First Quarter 2017

NSPI entered into [redacted] contracts for solid fuel supply in the first quarter of 2017.

IV.B.7.f. Second Quarter 2017

NSPI entered into [redacted] new contracts for solid fuel supply in the second quarter of 2017. These are shown in Figure IV-21.

Figure IV-21. NSPI New Solid Fuel Supply Contracts (Q2 2017)

Supplier	Product	Quantity	Term
[redacted]			

[20] NSPI retained the services of [redacted] to assist with the issuance and evaluation of the RFP. [redacted] also provided NSPI with consulting services regarding NSPI's annual biomass reporting to the government.

The [redacted] and [redacted] contracts were the product of a single RFP for low-sulphur coal. This was a notable RFP for a few reasons. First, it sought a fairly long-term commitment—up to five years of supply. Second, the [redacted] winning offer illustrated the effectiveness of NSPI's RFP and approval process. In its typical recommendation memo to FST, FERM clearly explained all bids received and recommended approval to enter into negotiations with [redacted] winning bidders: [redacted]. The FST approved the recommendations, and during negotiations with [redacted], it came to light that [redacted] provided "[redacted]." Specifically, [redacted] FERM evaluated this new information, determined that the [redacted] contract was still preferred, and negotiated [redacted]. This would protect NSPI from risk of [redacted] for the coal. FERM summarized these developments in a follow-up memo to the FST, which approved the continuation of the contracting process with [redacted]. Third, it featured a new bidder—[redacted], a provider of [redacted] coal—which actually was selected in the RFP. However, a final contract with [redacted] was not ultimately reached. Fourth, the RFP documentation showed clearly that NSPI's new hedging approach is being included in the analysis of physical RFP bids. Specifically, NSPI was almost fully hedged [redacted] for much of the period at issue in the RFP; the [redacted] contract [redacted] which—as NSPI pointed out—has [redacted] This meant that NSPI would be almost fully hedged [redacted]

The contract with [redacted] coal to NSPI. The contract, executed in April 2017, [redacted].[21] Further, NSPI noted itself that the [redacted]; thus, for the April 2017 deal, NSPI negotiated [redacted] contract for a [redacted] quantity (up to [redacted]) of [redacted][22] coal to be tested at Lingan. The contract gave NSPI the option but not the obligation to accept all [redacted] MT and [redacted]; that way, if the coal was tested and performed poorly, NSPI was not obligated to take the rest. In addition, [redacted]. This was an appropriate sharing of risk between the supplier and the buyer, and NSPI was protected from low-quality product by the aforementioned "option" nature of the contract. In the end, NSPI benefitted from the testing of the coal, including its mercury, ash, and sulphur content, as these data points would help them understand if and how [redacted] coal could

21 [redacted]

22 [redacted] did not yet have [redacted] at the time of the execution of this contract. Because the coal was [redacted], the expected quality of the product was lower, and the low price [redacted] delivered to Lingan) reflected this.

realistically be a part of its longer-term supply portfolio. As we point out in the discussion of third quarter 2017 contracts below, results would be positive.

IV.B.7.g. Third Quarter 2017

NSPI entered into [redacted] new contracts for solid fuel supply in the third quarter of 2017. These are shown in Figure IV-22.

Figure IV-22. NSPI New Solid Fuel Supply Contracts (Q3 2017)

Supplier	Product	Quantity	Term
[redacted]			

The contract with [redacted] for [redacted] coal was the [redacted] supply agreement executed in the Audit Period. This time, the contract was for [redacted] coal, which meant [redacted] price. Notably, the early test results of the [redacted] coal were positive, with Btu content of [redacted], ash content of [redacted], and sulphur content at [redacted] collectively, these are generally [redacted] and can have [redacted] for NSPI's fleet.[23] Moreover, at a price of [redacted] *delivered* to Lingan, the price for [redacted] coal is attractive. Note, for example, that the [redacted] had a price of [redacted],[24] a price that does not include the cost of [redacted], the cost of marine transport to Nova Scotia, the unloading costs, nor the rail costs to deliver the coal to NSPI's plants. Moreover, the [redacted] NSPI is currently negotiating with [redacted] for additional [redacted] coal.

The [redacted] contract was a sale of a small amount of petcoke (up to [redacted] MTs) by NSPI from its Point Tupper Marine Terminal at an indexed price. Under the contract, [redacted].

IV.B.7.h. Fourth Quarter 2017

NSPI entered into [redacted] new contracts for solid fuel supply in the fourth quarter of 2017. These are shown in Figure IV-23.

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23 The high Btu content of the [redacted] coal can help offset the lower Btu of the low-sulphur coal burned at NSPI's plants; the lower sulphur content of the [redacted] coal relative to mid-sulphur coal has a chemical benefit of increasing the effectiveness of powder activated carbon in abating mercury; the lower ash content means lower ash handling costs.

24 The [redacted] contract was the product of a solicitation of indicative bids among a short-list of NSPI's mid-sulphur suppliers and represented the lowest cost option of the [redacted] bids received.

Figure IV-23. NSPI New Solid Fuel Supply Contracts (Q4 2017)

Supplier	Product	Quantity	Term
[redacted]			

The [redacted] petcoke contract was meant to replenish [redacted] fuel supply at Point Aconi and was executed pursuant to a competitive RFP in which [redacted] offered the lowest priced bid. As is standard in NSPI's documentation of its RFP decision making, NSPI assessed the need for the purchase, ranked the bids on price, noted any qualitative considerations relevant to the bids, compared the bids to BCF costs and market index prices, assessed credit and country risk issues, and assessed compliance with the Fuel Manual.

The mid-sulphur purchases from [redacted] were based on NSPI's analysis of its inventory needs heading into the winter months, which showed NSPI was long on low-sulphur coal and in need of additional mid-sulphur coal. Two contracts resulted in a [redacted] the [redacted] cargo had a [redacted] price, consistent with the qualities of the respective coals. A second contract was based on [redacted] from [redacted], which was in line with market conditions at the time.

IV.B.7.i. NSPI's Physical Solid Fuel Positions at End of Audit Period

NSPI's physical solid fuel portfolio at the end of the Audit Period is shown in Figure IV-24 below. NSPI constantly tracks its physical positions for purposes of planning of physical purchases and incorporates its fixed price physical positions with its financial positions for the purposes of hedging (which is discussed in the Hedging chapter).

Figure IV-24. NSPI’s Physical Solid Fuel Portfolio as of December 31, 2017

[redacted]

IV.B.8. NSPI's Solid Fuel Procurement Process Assessment

NSPI's solid fuel procurement processes, clearly laid out in NSPI's Fuel Manual,[25] are designed to harness competition to lower costs for FAM customers. The process also allows NSPI to leverage its position as a buyer for multiple solid fuel-fired generators to achieve better results. This is because NSPI has the flexibility to ship its solid fuel to multiple ports and to burn much of its imported solid fuel at multiple units. With one exception (see next paragraph), NSPI's process includes clear guidelines and targets for its solid fuel portfolio, such as striving to have at least [redacted] suppliers, with no one supplier providing more than [redacted] of its annual needs, limiting exposure to a single country's solid fuel supply to no more than [redacted] of its needs, and not committing to any one single mine more than [redacted] of its purchases.[26] We observed just one violation of these guidelines during the Audit Period, as [redacted] represented [redacted] of NSPI's supply commitments in 2017. Given that (1) this violation was very small, (2) NSPI had [redacted] suppliers committed during 2017, and (3) Glencore is committed to provide just [redacted] of supply in 2018 and 2019, respectively, we found this violation to not be a significant concern.

The "exception" we found in the Fuel Manual is found in NSPI's Solid Fuel Portfolio Process document, which is Link 6 to the Fuel Manual. Table 1 is not clear to us: it appears to relate to hedging, which would include a mix of fixed-price physical purchases and financial positions. Table 1 requires a minimum of [redacted] and a maximum of [redacted] in the upcoming year to be "hedged"; however, this appears to conflict with NSPI's fuel-hedging plan. We address this issue more in the chapter on Hedging, and we include a recommendation to clarify this language.

NSPI's RFP process is well designed and encourages healthy participation by suppliers. Evidence of the success of the RFP process can be measured by participation throughout the Audit Period, which saw several suppliers offering multiple RFPs, and several winning suppliers. Importantly, too, NSPI negotiated with winning suppliers in good faith, meaning that NSPI honored the conditions of each winning bid, while still holding bidders to their promises in those bids. The RFP evaluation methodology is also reasonable, as it focuses on price, and takes into account transportation costs, quality adjustments, and environmental limitations. The RFPs also consider counterparty risk, such as credit and country risk.

Another process that is crucial is NSPI's process for recording the procurement approval by the FST, which is well documented and contained in the Fuels Data Cart. These "Record of Procurement Approval" documents are issued for all solid fuel procurements—not just those related to RFPs. These documents ensure that purchases are vetted by management and are sufficiently justified, including showing the need for the purchase, the reasons for transacting with the counterparty, and the evaluation modeling done by FERM to assess the transaction. While solid fuel procurement can become routine, this Audit Period demonstrates why this approval process is so important—in the Record of Procurement Approvals we reviewed, NSPI clearly explained how it was addressing two unique events: the decline of

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25 See, e.g., Link 8 "Solid Fuel Portfolio Process" of the Fuel Manual.

26 Link 8 "Solid Fuel Portfolio Process" of the Fuel Manual.

one [redacted] source of supply [redacted] and the emergence of another [redacted]. Given that these two unique events impact more than just a single procurement decision on solid fuels, these records are important touchstones for NSPI management to clearly understand and document its assessments through time.

In practice, we found NSPI's procurement processes to be effective. While NSPI is not required by the Fuel Manual to exclusively rely on RFPs for solid fuel supply, we found evidence that the RFP was NSPI's favored approach. When circumstances did not allow sufficient time for an RFP, NSPI at least sought indicative pricing from multiple suppliers, and in no instances did we observe prices that were out of line with overall market conditions, nor did we see any instances of NSPI selecting offers that were not the lowest cost.

IV.B.9. Contract Actions

IV.B.9.a. Resales or Swaps

In the third quarter of 2017, NSPI executed Amendment 1 to a July 14, 2016, contract with [redacted] for Colombian coal. The amendment [redacted], an action NSPI took in response to its inventory positions, which showed a need for mid-sulphur coal and an excess of low-sulphur coal.

IV.B.9.b. Litigation Related Contract Issues

In December 2016, NSPI entered into settlement negotiations with [redacted] regarding [redacted] failure to deliver the fourth and final cargo of [redacted] pursuant to its supply agreement. On March 9, 2017, the parties reached a settlement and amended their agreement to resolve all issues related to the 2016 event; under the terms of the amendment, NSPI would receive a shipment of [redacted] of [redacted] in either March or April of 2017 for a price of [redacted]. While the price of this shipment was identical to that contained in the 2016 contract with [redacted], the quantity represented [redacted] MTs.

IV.B.9.c. Force Majeure

[redacted]—NSPI's marine freight shipping provider—declared force majeure on October 22, 2016, when one of its vessels [redacted] while berthing to lift a cargo NSPI had contracted from supplier [redacted]. NSPI negotiated with both [redacted] and [redacted] to arrange a substitute vessel; that vessel was slightly bigger than the previously nominated cargo of [redacted] MTs. In total, NSPI received an extra [redacted] MTs, a reasonable overage given the nature of the incident.

IV.B.9.d. Terminations

On June 30, 2016, and July 5, 2016, respectively, NSPI terminated biomass supply contracts with [redacted] and [redacted]. NSPI explained that the April 8, 2016, decision by the Nova Scotia government to end the PHP biomass unit's must-run status,[27]

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[27] Nova Scotia Canada, "Government Ends Must-Run Regulation, Reduces Biomass Use," April 8, 2016, *available at*

thereby allowing NSPI to run the unit on an economic basis, had a dramatic impact on the expected usage of the biomass unit. This has been borne out: in 2015, the biomass unit consumed almost [redacted] green MTs of biomass fuel;[28] in 2016, that amount fell by about [redacted] to [redacted] green MTs; in 2017—the first full year of economic operation of the biomass unit—consumption fell by a [redacted] to about [redacted] green MTs. Moreover, NSPI's expectations for biomass fuel consumption fell even further—as shown above in Figure IV-4, NSPI forecasted to consume just over [redacted] green MTs in 2017.

Given the reduced need for biomass fuel, NSPI no longer needed the quantities under contract with [redacted] and [redacted], both of which called for minimum delivery quantities of both primary and secondary biomass fuel. The [redacted] contract called for [redacted] green MTs of primary and [redacted] MTs of secondary biomass fuel, [redacted].[29] [redacted] contract quantities were even higher, calling for [redacted] green MTs of primary and [redacted] green MTs of secondary biomass fuel, [redacted].[30] Given that the biomass unit's expected consumption had decreased from over [redacted] green MTs in 2016 (when it was expected to be a must-run unit for the full year) to just over [redacted] green MTs in 2017 (its first full year as a non-must-run unit), NSPI clearly did not need the large quantities of biomass fuel afforded by the [redacted] and [redacted] contracts, which, together, provided NSPI with [redacted] green MTs of primary biomass fuel and [redacted] of secondary biomass fuel—or [redacted] green MTs of overall combined biomass fuel—annually.

Both contracts offered NSPI with the right to terminate, and in both cases, NSPI would be responsible for payment to the supplier.

- The contract with [redacted] stated that if NSPI's requested deliveries fall below [redacted] green MTs for a given year, NSPI would pay [redacted] a fee of $[redacted][31]/green MT for all [redacted] green MTs. So, whether NSPI cut its requested quantities in a given year to [redacted] green MTs or to [redacted] green MTs, the payment due from NSPI to [redacted] would be the same: [redacted] green MTs, for each year of the contract. Thus, when NSPI terminated the contract, it was required to pay [redacted] these amounts for the remaining years of the contract. In total, this payment equaled [redacted], which NSPI remitted, thereby ending the contractual relationship with [redacted]. Given that NSPI was forecasting consumption to be far below this contract minimum of [redacted] green MTs, NSPI would not have reached the [redacted] green MT minimum. Had NSPI not terminated the contract, and had it received deliveries of less than [redacted] green MTs, NSPI would have still been charged the same [redacted]. In other words, regardless of whether

https://novascotia.ca/news/release/?id=20160408002.

28 Q4 2016 FAM Report, page 33.

29 Note that the secondary biomass deliveries requirement did not extend through the full life of the contract.

30 Note that the secondary biomass deliveries requirement did not extend through the full life of the contract.

31 The contract allowed the management fee to increase with inflation.

NSPI had terminated the contract or simply requested fewer than the [redacted] green MT minimum, NSPI would have been responsible for paying Wagner this amount.

- The contract with [redacted] was even more severe. It required NSPI to pay a [redacted]/green MT management fee for [redacted] green MTs if NSPI reduced its requested deliveries below [redacted] MTs. Another difference in the [redacted] contract was that, in the event of termination, NSPI would pay [redacted]. So, again, like the [redacted] contract, NSPI would be responsible for a substantial payment in the event of either termination or reduced requested deliveries. In the case of the [redacted] contract, NSPI made a payment of [redacted]; however, this is only a portion of the amount due. NSPI and [redacted] disagree on the final amount due under the contract and are currently engaged in legal discussions to determine that amount. NSPI claims that the maximum it expects to pay would be an additional [redacted]. NSPI notes that the [redacted] "is currently accruing and is already included in the FAM costs." This would bring the total payment to [redacted] to [redacted], which is approximately equal to the [redacted]/green MT management fee times the annual minimum threshold of [redacted] green MTs for the term of the contract, pro-rated to account for months in which the biomass unit remained must run. NSPI also notes that if the actual payment to [redacted] is negotiated to be something less, FAM customers will receive a credit.

NSPI's decision to terminate the [redacted] and [redacted] biomass contracts was prudent. As we explain above, the provincial decision to remove the must-run designation from the PHP biomass unit meant a dramatic reduction in forecasted biomass fuel consumption at the plant, so much so that NSPI would have been forced to choose between violating the "minimum" delivery thresholds under each contract or to accept far more biomass fuel than it needed. Further, the cost of termination of both contracts was the same as that which would have been due to the suppliers had NSPI not terminated the contracts but reduced their requested deliveries to reasonable quantities. [redacted].[32] (The [redacted] contract, unlike the [redacted] and [redacted] contracts,[33] was a [redacted], reducing price risk for NSPI ratepayers.) As noted in our discussion of that [redacted] contract, several other offers were received in the RFP in which the [redacted] offer was selected, including [redacted], which submitted a more expensive offer than [redacted].[34]

32 [redacted] offer compared to [redacted] demonstrates a cost of about [redacted]/green MT under the [redacted] contract. This compares favorably to the schedule of deliveries from [redacted] in 2016, which average to about [redacted]/green MT.

33 Both the [redacted] and the [redacted] contracts had unique pricing terms: each stated that [redacted] supply of Biomass Fuel to Port Hawkesbury Biomass Plant."

34 A further benefit of the [redacted] arrangement was [redacted] offer of a [redacted].

Given the outstanding nature of the [redacted] termination payment, and given that NSPI has already charged FAM customers for the expected maximum penalty that may be due to [redacted], we include a recommendation that NSPI report to the Board upon resolution of this issue, explaining the agreed-upon final termination payment and demonstration of the proper crediting to FAM customers, including applicable interest.

IV.B.9.e. Renegotiations, Amendments, or Extensions

During the Audit Period, the following changes to NSPI's existing solid fuel supply contracts occurred:

- Addendum No. 2—dated January 28, 2016—was executed to amend NSPI's March 4, 2013, freight contract with [redacted]. The amendment extended the contract by 15 days to February 15, 2016, while NSPI continued negotiations with [redacted] on a five-year contract extension.
- On June 3, 2016, NSPI executed an addendum to a railroad transportation contract with [redacted]. The pricing in the original contract, executed in 2015 and under which [redacted] provides servicing on NSPI-owned railcars (e.g., inspections), was based on NSPI providing [redacted]. The addendum specifies costs NSPI must pay if it increased the number of railcars.
- On January 13, 2016, NSPI executed Amendment No. 1 to a coal supply contract with [redacted] to amend the delivery schedule.
- Effective March 24, 2016, NSPI amended a petcoke supply agreement with [redacted] to specify the price at which NSPI would pay for petcoke should it exercise its option for [redacted].
- On October 26, 2016, NSPI executed Amendment No. 2 to a confirmation letter dated December 23, 2015, with [redacted] for petcoke supply. The amendment changes the [redacted].
- On August 9, 2016, NSPI executed Amendment No. 2 to a coal supply contract with [redacted] to amend the delivery schedule.
- On December 16, 2016, NSPI amended its agreement with [redacted] for coal from the [redacted]. Under the amendment, [redacted] is required to provide [redacted] MTs, with NSPI retaining the right to purchase up to a total of [redacted] MTs. NSPI's analysis showed a savings of [redacted], compared to the BCF forecast and between [redacted] and [redacted] compared to [redacted] alternatives.
- On January 5, 2017, NSPI executed Amendment No. 1 to a supply contract with [redacted] for [redacted] mid-sulphur coal. The amendment specified several cargoes of mid-sulphur coal to be delivered throughout 2017 and into 2018.

- In July 2017, NSPI executed Amendment No. 1 of a 2015 contract with [redacted] to reflect the correct execution of the original contract.
- In the fourth quarter of 2017, NSPI executed two amendments to contracts with [redacted]. One [redacted] the 2018 contracted quantity by [redacted] due to updated inventory forecasts; the second amendment specified the indexed price for a cargo to be shipped in December 2017.
- On December 21, 2017, NSPI executed an amendment to a confirm with [redacted] related to a shipment of petcoke, specifying the [redacted]
- On September 28, 2017, NSPI amended its existing master supply agreement with [redacted]. The amendments updated the financial and credit terms of the 2005 contract.

IV.B.10. Other Procurement

NSPI's significant procurements in other services or products related to solid fuels are included in this section.

Marine Freight Shipping: On February 10, 2016, NSPI agreed to a contract extension with [redacted], which provides NSPI's marine freight shipping of solid fuels. The contract was extended through [redacted]. Under the terms of the extension, [redacted] would deliver an estimated solid fuel quantity of [redacted] of solid fuel ([redacted] at NSPI's option [redacted]; that number would [redacted] annually [redacted], with NSPI retaining an option to extend the agreement into [redacted]. This contract extension was the product of a competitive RFP held in 2015, which was reviewed by the previous fuel auditor.[35]

Powder-Activated Carbon: NSPI uses Activated Carbon Injection technology to capture mercury at Lingan, Point Tupper, and Trenton, and purchases and utilizes powder-activated carbon in that process. In 2016, NSPI consumed [redacted] in powder-activated carbon; in 2017, NSPI consumed [redacted]. On January 1, 2016, NSPI extended its existing agreement with [redacted] for the provision of powder-activated carbon and management of the associated supply chain. The amendment extended the term of the agreement until June 30, 2017. NSPI conducted a thorough analysis of this contract extension, noting too that NSPI had tested [redacted] competitive alternatives to [redacted] product and found that [redacted] product achieved the necessary [redacted] at the lowest cost. On July 17, 2017, NSPI executed Amendment No. 3 to the agreement with [redacted], extending the agreement through June 30, 2020, at a price decrease from the prior two contract extensions. This contract has several positive aspects, including [redacted]

[35] Liberty 2014-2015 FAM Audit Report, page IV-22.

[redacted]

Calcium Chloride: On April 4, 2017, NSPI executed a [redacted] contract for the supply of calcium chloride, which is consumed at Lingan, Point Tupper, and Trenton units as part of NSPI's mercury abatement program. The counterparty on the new contract was [redacted]., which had served as NSPI's calcium chloride provider for [redacted]. NSPI issued an RFP in February 2017, seeking a new supplier and inviting [redacted] entities to bid; [redacted] submitted bids, with [redacted] bid being the lowest cost. NSPI management, in its analysis of the RFP, noted that [redacted] had been a high-quality supplier in NSPI's experience over [redacted].

Railcar Leases: In the fourth quarter of 2016, NSPI extended its leases with two providers of railcars, which NSPI leases for the purposes of moving coal from Point Tupper Marine Terminal to Trenton. On November 9, 2016, NSPI exercised its option to extend its contract with [redacted] for the leasing of 60 railcars for three additional years for [redacted]. On December 1, 2016, NSPI amended its railcar lease agreement with [redacted] for an incremental [redacted] cars to extend the term through November 30, 2019, and [redacted] the price for the monthly rental cost from [redacted]. Both lease extensions were assessed against market alternatives—a total of [redacted] potential providers were contacted; [redacted] submitted offers, with [redacted] others indicating that they had no railcars available to lease. NSPI's assessment of the offers was robust: they focused first on [redacted] was the lowest cost offer. NSPI then assessed [redacted] and if so, from which supplier. NSPI noted that the [redacted] railcars act as an insurance policy against replacement of frozen railcars that are out of service, increased rail capacity to make up for lost shipping days due to weather, or to build coal piles for winter readiness, as well as the need for [redacted] NSPI then identified [redacted] as the lowest cost offer, but also compared the cost of [redacted] to a [redacted]

Rail Transport from Point Tupper Marine Terminal to Trenton: On December 20, 2017, NSPI negotiated a one-month extension of its existing contract with [redacted], which was due to expire on December 31, 2017. [redacted] provides NSPI with railroad transportation services from Point Tupper Marine Terminal to the Trenton units, delivering solid fuel. The purpose of the extension was to allow for continued negotiations between the parties on a longer-term extension. The new expiration date was to be January 31, 2018; the terms and conditions of the contract remained the same. [redacted] potential supplier of rail service from Point Tupper Marine Terminal to Trenton; [redacted] alternative to using [redacted] rail service is [redacted], which NSPI determined to be [redacted] NSPI's analysis also shows that although the overall coal consumption fleetwide is expected to continue to fall, the need for rail service to bring coal from Point Tupper Marine Terminal to Trenton [redacted]

[redacted]

Limestone Quarry Services: NSPI consumes limestone in its boiler at Point Aconi as part of its unique fluidized bed design.[36] The limestone comes from the [redacted] in Cape Breton. For several years, [redacted] had operated the [redacted] on behalf of NSPI; that agreement was due to expire on December 31, 2017. On December 20, 2017, NSPI extended the agreement with [redacted] at the same terms and conditions under the existing agreement for an additional year, through December 31, 2018.

IV.B.11. Environmental Matters

NSPI is subject to provincial regulations and laws that govern the allowable emissions from its generating facilities. Specifically, NSPI faces limits on emissions of sulphur dioxide (SO_2), nitrous oxide (NO_x), Hg, and carbon dioxide (CO_2). Figure IV-25 shows NSPI's fleetwide limitations on SO_2, NO_x, and Hg.

Figure IV-25. NSPI's Fleetwide Emissions Limits under Nova Scotia's Air Quality Regulations[37]

Compliance Period	SO2 (tons)	NOx (tons)	Mercury (kg)
2015-2019	304,500 (fleetwide full period) 72,500 (fleetwide annual) 42,775 (unit limit - annual)	96,140 (fleetwide full period) 21,265 (fleetwide annual)	65 (fleetwide annual)
2020	36,250 (fleetwide)	14,955 (fleetwide)	35 (fleetwide)
2021-2024	136,000 (fleetwide full period) 36,250 (fleetwide annual) 17,760 (unit limit - annual)	56,000 (fleetwide full period) 14,955 (fleetwide annual)	35 (fleetwide annual)
2025	28,000 (fleetwide) 13,720 (unit limit)	11,500 (fleetwide)	35 (fleetwide)
2026-2029	104,000 (fleetwide full period) 28,000 (fleetwide annual) 13,720 (unit limit - annual)	44,000 (fleetwide full period) 11,500 (fleetwide annual)	35 (fleetwide annual)
2030	20,000 (fleetwide) 9,800 (unit limit)	8,800 (fleetwide)	30 (fleetwide)

Figure IV-26 shows NSPI's applicable limitations on CO_2 emissions.

36 NSPI consumed [redacted] and [redacted] in 2016 and 2017, respectively, in limestone at Point Aconi.

37 *Air Quality Regulations,* made under sections 25 and 112 of the *Environment Act* S.N.S. 1994-95, c. 1 O.I.C. 005-87 (February 25, 2005, effective March 1, 2005), N.S. Reg. 28/2005 as amended to O.I.C. 2017-255 (October 12, 2017), N.S. Reg. 150/2017, Schedule C.

Figure IV-26. NSPI's Fleetwide CO_2 Equivalent Emissions under Nova Scotia's Greenhouse Gas Emissions Regulations[38]

Compliance Period	CO_2e (mega tons)
2017-2019	24.06 (cumulative total)
2020	7.5
2021-2024	27.5 (cumulative total)
2025	6.0
2026-2029	21.5 (cumulative total)
2030	4.5

NSPI is also required to supply its customers with electricity generated from at least 25% renewable sources each year until 2020;[39] beginning in 2020, that share must be at least 40%.[40] (NSPI met its applicable targets in the Audit Period.)

To maintain compliance with emissions limitations, NSPI manages its procurement and use of fuels. At solid fuel-generating stations, this is done through the blending of fuels with appropriate sulphur and mercury content to meet emissions limits. NSPI operates low NO_x burners at Point Tupper, Trenton 6, Tufts Cove 2 and 3, and the four Lingan units to manage NO_x emissions. And NSPI uses powder-activated carbon at Lingan, Point Tupper, and Trenton to manage mercury emissions. NSPI monitors its emissions in real-time, something we verified on our site visits. NSPI also manages a groundwater management program to comply with groundwater requirements; each plant has a wastewater treatment facility (to comply with wastewater limitations) and an ash management program (to comply with ash limitations).

At the biomass facility, NSPI must also comply with sustainability requirements. To this end, NSPI had agreements in place with (1) the Canadian Food Inspection Agency, which requires NSPI to follow certain inspection, storage, and disposal protocols for its biomass fuel; (2) Nova Scotia Natural Resources in the form of a Forest Sustainability Agreement; and (3) the [redacted] for assistance in developing an annual silviculture plan, which is part of NSPI's legislative requirements in buying biomass fuel for the PHP biomass plant.

IV.C. Conclusions

Conclusion IV-1: NSPI's codified processes for solid fuel procurement as found in the Fuel Manual are sound.

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38 *Air Quality Regulations,* made under sections 25 and 112 of the *Environment Act* S.N.S. 1994-95, c. 1 O.I.C. 005-87 (February 25, 2005, effective March 1, 2005), N.S. Reg. 28/2005 as amended to O.I.C. 2017-255 (October 12, 2017), N.S. Reg. 150/2017, Schedule C.

39 *Renewable Electricity Regulations*, made under Section 5 of the *Electricity Act* S.N.S. 2004, c. 25 O.I.C 2010-381 (October 12, 2010), N.S. Reg. 155/2010 as amended to O.I.C. 2017-187 (July 17, 2017), N.S. Reg. 108/2017, section 6.

40 *Id.*, section 6A.

Conclusion IV-2: NSPI's execution of procurement of coal and petcoke during the Audit Period was consistently sound and resulted in reasonable supply contracts.

Conclusion IV-3: We found no evidence of NSPI not following the guidelines set forth in its Fuel Manual for coal and petcoke procurement.

Conclusion IV-4: NSPI consistently sought competitive bids for solid fuel supply, whether through the RFP process—which was the primary method of procurement—or through other means.

Conclusion IV-5: NSPI's process for vetting proposed procurement transactions through the FST via detailed memos and/or presentations on FERM's recommended approach is robust, establishes the "need" for any proposed transactions, considers competitive alternatives, and was consistently applied throughout the Audit Period. Documentation of this process was also effective, including use of Record of Procurement Approval documentation and maintenance of the Fuels Data Cart.

Conclusion IV-6: NSPI effectively used competition and comparative alternatives in procuring other solid fuel services, such as transport and additives, during the Audit Period. For products that have a [redacted], such as rail transportation services to Trenton or domestic coal supply, NSPI considered the next best competitive alternative and engaged in robust negotiations for the service.

Conclusion IV-7: NSPI consistently considered the relevant risks of each transaction, such as counterparty credit risk and country risk, when applicable. CROC approval was sought and received when required.

Conclusion IV-8: NSPI effectively managed the procurement of biomass fuel in light of the provincial decision to no longer operate the Port Hawkesbury biomass unit under must-run status as of April 8, 2016. This decision, naturally outside the control of NSPI, represented a sea change in the operation of the unit and its biomass fuel needs, and NSPI responded accordingly, cancelling two [redacted] biomass supply arrangements for a higher-quality blend of biomass fuel needed to operate the unit as must-run, and replacing it with a [redacted] contract for a smaller quantity.

Conclusion IV-9: NSPI's decision to cancel the biomass contracts with [redacted] and [redacted] resulted in termination payments to those suppliers. In both cases, the decisions were prudent, for reasons we identify in our Findings section. The payment to [redacted] has fully resolved any outstanding issues with the supplier; [redacted] payment has been made in part but remains unresolved. NSPI has already charged FAM customers for the expected maximum termination payment that could be due and has committed to crediting FAM customers if the actual payment is lower than the maximum. NSPI should update the Board when this issue is resolved and should demonstrate that FAM customers have been properly credited, with applicable interest. (Recommendation)

Conclusion IV-10: NSPI effectively introduced [redacted] coal supply into its solid fuel portfolio. This was no simple task, as the [redacted]. NSPI engaged in negotiations with [redacted]

[redacted] during 2016, effectively and prudently negotiating an option contract for 2017 supply. When the commercial operations date of the [redacted] was delayed into 2017, NSPI appropriately balked at the option contract. Once the mine was online, NSPI appropriately purchased a modest amount of [redacted] coal for testing ([redacted]) and later a similar shipment of [redacted] coal for further testing. Our analysis of comparable contracts for mid-sulphur coal imports suggests that [redacted] could be a [redacted], as evidenced by early testing of the [redacted] coal's Btu and ash content. Nevertheless, the [redacted] future is still subject to risks; in our high-level estimation, [redacted]. NSPI is well equipped to consider these risks and to contract accordingly. We expect the next FAM Audit to look closely at NSPI's decision to contract (or not contract) with [redacted] for a longer-term, higher-quantity contract for [redacted] coal. However, we offer no recommendation on this matter, since we have no reason to question NSPI's ability to evaluate the risks and benefits of such a contract.

Conclusion IV-11: During the Audit Period, NSPI effectively addressed the [redacted]. We observed numerous instances in NSPI's analysis of transactions for [redacted] (contained in the Fuel Data Cart) of NSPI considering the short- and longer-term impacts of [redacted]. Contracts with [redacted] supply were well vetted and remained the lowest cost option for Trenton 6. Contracts with rail service providers [redacted] for Trenton 6.

Conclusion IV-12: Because Trenton 6 was specifically designed to efficiently burn the high ash content coal [redacted], and because the Trenton 6 unit's useful life will likely [redacted], two issues are worth noting. First, it will be important to track the performance and cost of the Trenton 6 unit going forward as the [redacted] becomes a smaller part of its fuel blend. As we note elsewhere, NSPI has a robust asset management programme, so we have no reason to doubt that NSPI will not do this, but it is a point worth drawing out for the Board and for stakeholders. Second, given that the [redacted] supply ideally would have survived the useful life of Trenton 6, there is a question about whether this [redacted]. This decision, which was made before the privatization of NSPI, and advance of the unit's 1991 commercial operations date, far predates our Audit Period review.

IV.D. Recommendations

Recommendation IV-1: Given the outstanding nature of the [redacted] biomass termination payment, and given that NSPI has already charged FAM customers for the expected maximum penalty that may be due to [redacted], NSPI should report to the Board upon resolution of this issue, explain the agreed-upon final termination payment, and demonstrate that it has properly credited FAM customers, including applicable interest.

V. Solid Fuel Supply Management

V.A. Background

Effectively procuring solid fuel—coal, petcoke, and biomass—is just part of a utility's effective approach to burning solid fuel for electricity generation. In this chapter, we review and assess the other essential part of this process—management of the solid fuel supply. We begin by looking at how solid fuel arrives at NSPI's assets and how NSPI tracks this information. We then assess NSPI's processes for weighing, sampling, and analyzing solid fuel that it has purchased. Next, we consider NSPI's approach and effectiveness of solid fuel contract administration. We then review NSPI's solid fuel suppliers' compliance with NSPI's contract terms over the Audit Period. We then review and assess NSPI's coal inventories. We conclude with a review of NSPI's approach to and results of physical inventory measurements and adjustments during the Audit Period.

V.B. Findings

V.B.1. NSPI's Process for Solid Fuel Receipt Information

V.B.1.a. General Information: Coal and Petcoke

NSPI uses Aligne—which is an off-the-shelf database software owned by Fidelity National Information Services—as its transactional backbone in tracking its solid fuel. Aligne allows NSPI to reconcile the entire solid fuel supply chain, including solid fuel contract data, solid fuel received, solid fuel burned, solid fuel testing and results, and solid fuel transportation, in a single database. Aligne interacts directly with other NSPI programs—such as Oracle, NSPI's billing software—thus reducing the likelihood of errors across the long chain of solid fuel management, from contract origination all the way to billing of FAM customers.

NSPI receives its imports of solid fuel on marine vessels at two ports: the International Pier in Sydney and the Point Tupper Marine Terminal in Port Hawkesbury. These two piers represent the two major hubs of coal and petcoke shipments for NSPI's fleet, with Sydney serving the Lingan and Point Aconi plants and Point Tupper serving the co-located Point Tupper unit as well as the Trenton units. Shipments from Colombia generally take about ten days to reach Nova Scotia; shipments from the US Gulf Coast take about nine days, while shipments from Baltimore take about four days.

NSPI contracts with [redacted] to operate the International Pier, which includes the handling, storage, warehousing, reclaiming, loading into railcars and trucks, operating the railway (to Lingan), and delivery of solid fuel from the International Pier to both Lingan and Point Aconi. NSPI also contracts with [redacted] to operate the Port Tupper Marine

Terminal, which includes receiving shipments, unloading, handling, storage, reclaim, loading railcars (for Trenton), loading reclaim hoppers at Point Tupper, and transporting solid fuel to Bear Head (a storage area near the Terminal), among other services.

In addition to international shipments of low- and mid-sulphur coal and petcoke, NSPI also purchased domestic coal from [redacted] sources during the Audit Period—[redacted] for Trenton 6 [redacted] for Lingan—as well as domestic biomass roundwood, wood chips, and bark for the Port Hawkesbury biomass plant. Domestic solid fuel is purchased on an as-delivered basis and is trucked to NSPI's plants.

When imported solid fuel is received from an ocean-going vessel, it is offloaded into solid fuel piles at either International Pier or the Point Tupper Marine Terminal. Upon transfer of coal ownership to NSPI, the quantity and costs associated with that solid fuel become part of the quantity and weighted average cost of that pile. The solid fuel in those piles is then moved to the generating plants as required. When solid fuel is moved from an offloading facility to the generating plants, the quantity and weighted average cost of the solid fuel at the time are transferred to the plant, modifying the quantity and weighted average cost of the corresponding solid fuel pile located at the generating plant, which was received from prior deliveries.

When coal is purchased from a domestic source, i.e., [redacted], it is trucked from the mine directly to the plant. When the coal arrives, it is added to the appropriate inventory location at the plant, and the costs associated with that coal become part of the average unit cost at the inventory location. Once the fuel has been recorded in Oracle, the Aligne Administrator/Specialist at the respective plant indicates on the invoice that the receipt has been executed, generally by writing the purchase order and receipt numbers on the invoice. This information is sent to NSPI's Accounts Payable for payment.

Regarding NSPI personnel responsibilities, FERM is responsible for determining solid fuel requirements; procuring solid fuel; entering into solid fuel purchase transactions; undertaking the corresponding fuel supply contract administration; managing the marine receiving ports, including the receipt of solid fuel, i.e., unloading of marine vessels; tracking the fuel quantity and quality received; and delivering the solid fuel to the individual generating plants. Individual plant personnel, meanwhile, are responsible for receiving the fuel onto their site (e.g., unloading of rail cars) and maintaining the fuel stock piles.

Solid fuel imported shipments are tracked via an Excel spreadsheet called the Vessel Schedule. The Coal Procurement and Logistics Specialist is responsible for managing and maintaining the Vessel Schedule on the Fuels SharePoint site. Delivery can be, at NSPI's option, to either the Point Tupper Marine Terminal or International Pier. The Coal Procurement and Logistics Specialist begins to develop the scheduling of vessels via the Coal Inventory Model approximately four months prior to the beginning of each calendar year. The applicable quarterly forecast for the upcoming year is used to establish when tentative shipments should be scheduled, based on the forecast quantities by commodity by plant. The

Coal Procurement and Logistics Specialist uses the Coal Inventory Model to schedule shipments based on a six-week trigger point by commodity into both International Pier and Point Tupper Marine Terminal throughout most of the year, with the exception of late third quarter through the end of the year, when shipments escalate for winter readiness. Once tentative shipment periods are identified, the Vessel Schedule development begins by linking all shipments to existing contracts against tentative loading periods. The Vessel Schedule includes pertinent tracking details for each NSPI coal and petcoke shipment, such as shipper, supplier, load date, disport date, load port, country of origin, year of schedule, status of shipment (i.e., confirmed/not confirmed), and link to appropriate contract date. The Coal Procurement and Logistics Specialist uses this Vessel Schedule to provide guidance to both solid fuel suppliers and [redacted] on NSPI's shipment requirements throughout the year. The Logistics Administrator then uses the Vessel Schedule to link each shipment to its appropriate contract and enter into Aligne for purchase order generation and shipment tracking of vessels.

For transport to NSPI's five coal generating stations (Lingan, Point Aconi, Point Tupper, and Trenton 5 and Trenton 6), the Senior Contract Administrator of NSPI's Fuels group is involved in daily and weekly monitoring and delivery of coal and petcoke to each facility. The Senior Contract Administrator uses and updates an Excel spreadsheet to track the estimated arrival times of projected vessel deliveries by coal type arriving at NSPI's two terminals. The spreadsheet also tracks the deliveries by domestic fuel suppliers, the current site inventories (tonnes by coal type), and the projected deliveries (tonnes by coal type) for each generating facility, which is netted off against the projected consumption of each coal type. The spreadsheet is actualized, at minimum, two times per week. The Senior Contract Administrator discusses the planned deliveries with each generating facility to determine if deliveries need to be altered in reaction to any operational or inventory situations that may have arisen. Weekly conference calls are also conducted with the generating facility operators or coal handling personnel to discuss the vessel arrivals and the fuel's subsequent transport in addition to a verification of current inventory levels at each site. The Senior Contract Administrator communicates daily with NSPI's terminal operators ([redacted] at Point Tupper and [redacted] at International Pier) to discuss upcoming vessel arrivals and unloading and stockpiling efforts for all coal and petcoke received. Discussions with terminal personnel centered on strategic stockpiling for ease of rail or truck transport while planning for storage for incoming vessels. The Senior Contract Administrator regularly liaises with the Coal Procurement and Logistics Specialist to discuss any inventory constraints that may require action, e.g., rescheduling a shipment or a blend change.

V.B.1.b. General Information: Biomass

NSPI also uses the Aligne database in tracking biomass deliveries, but the process differs somewhat from the coal and petcoke process. NSPI receives all biomass deliveries by truck. Upon arrival, deliveries are weighed using WeighWiz, which is a commercially-available weigh scale system for truck deliveries. Upon capturing the weight of the delivery, as well as the type of biomass fuel (e.g., wood chips), vender, and delivery location, the information is automatically transferred to the Log Inventory and Management System (LIMS), which is an off-the-shelf software program for managing timber and wood products, with the ability to track procurement, contractor payables, contract management, inventory, consumption, and accounting. The LIMS system is queried on a weekly basis to summarize this information, and the Senior Contract Administrator of biomass compares it against vender invoices. When the vender invoices are received, the delivery information is entered into Aligne. Once the fuel has been recorded in Oracle, the Aligne Fuels Administrator/Specialist indicates on the invoice that the receipt has been executed, generally by writing the purchase order and receipt numbers on the invoice. This information is sent to Accounts Payable for payment.

V.B.1.c. Plant-Specific Information: Lingan

Lingan primarily burns imported coal, which again arrives by marine vessel at the International Pier. From there, the coal is typically shipped by railcar to Lingan. These deliveries are weighed on certified belt scales at the railcar loading facility at the International Pier. Until October 2017, the weights from the belt scale were entered manually into a data management system known as I-Tract by [redacted] personnel. In late 2017, this data entry system was upgraded to allow direct transmission of the weight data from the scales to the new data management system—the [redacted] system. Since that time, plant personnel have used the [redacted] system to record the coal deliveries in Aligne.

Under NSPI's contract with [redacted], coal is shipped by rail on NSPI's rail system. ([redacted].) NSPI provides [redacted] with weekly updates regarding solid fuel shipments as well as solid fuel needs at Lingan and Point Aconi. Upon arrival at the plant, the railcars are emptied and the contents transported underground to a feeder, which empties onto the active coal pile. As the coal is unloaded, plant personnel create a record of each of the car numbers that are unloaded in each train delivery, along with the type of fuel as designated by [redacted]. NSPI compares and verifies this unloading record with the information in the data management system on a daily basis. Once all deliveries for the day are confirmed and the weights are obtained, the deliveries are recorded in Aligne. On a monthly basis, the delivery records in Aligne are compared and verified with the monthly summaries in the data management system, as reported by [redacted].

NSPI's contract with [redacted] was premised upon [redacted] being handled at International Pier; in the case of Lingan, the contract notes that [redacted]. Notably, [redacted]

V.B.1.d. Plant-Specific Information: Point Aconi

Point Aconi, which burned only imported petcoke and imported low-sulphur coal during the Audit Period, receives all its fuel by truck from the International Pier under NSPI's agreement with [redacted]. The loaded trucks are weighed on a certified truck scale just outside the International Pier site, and the truck driver receives a printed weigh ticket from this scale. When the trucks arrive at Point Aconi, the commissionaire at the plant records the truck numbers, fuel type, date, and time and receives the weigh tickets from the truck driver. The following day, the truck scale at the International Pier automatically emails a report to Point Aconi personnel showing all the individual truck numbers, weights and types of fuel delivered. Point Aconi personnel compare this summary to the individual weigh tickets collected the previous day and once those numbers are reconciled, the total weight of each fuel type received for the day is entered into Aligne.

Again, NSPI's contract with [redacted] was premised upon [redacted] handled at International Pier; in the case of Point Aconi, the contract notes that [redacted]

V.B.1.e. Plant-Specific Information: Trenton

Trenton 5 was reliant on imported low- and mid-sulphur coals for 100% of its fuel during the Audit Period, while Trenton 6 burned a combination of domestic [redacted] coal, imported low-sulphur coal, and imported petcoke. All imported coal and petcoke for the Trenton units arrives by marine vessel at the Point Tupper Marine Terminal, which, like the International Pier, is owned by NSPI.[1] (NSPI receives about 25 shipments per year into the Point Tupper Marine Terminal.) Coal and petcoke are transported from the Point Tupper Marine Terminal to Trenton by railcar, with a typical week seeing one shipment per weekday of 19–26 cars, a one-way trip that takes about 12 hours. Today, NSPI uses steel railcars but is considering a shift to aluminum cars. The coal in the cars is weighed at the Marine Terminal using the loader weightometers. [redacted], the operator of Point Tupper Marine Terminal, provides a report each day of the weights and coal types that are loaded into each car. Trent unloading personnel use this report to determine where the fuel in a car is to be stockpiled—that is, added to the piles for use at Trenton 5 or Trenton 6. Blending of Trenton 5's fuel (as well as the imported portion of Trenton 6's fuel) is done at Point Tupper Marine Terminal; blending of Trenton 6's imported and domestic fuel is done at the plant.

Upon arriving at Trenton, the railcars are emptied from the bottom, where the coal falls from the railcar into a hopper and onto a belt. The belt carries the coal to the appropriate piles for Trenton 5 and 6. Trenton unloading personnel record the railcar numbers, delivery date, and weights going to each pile.

Domestic coal from [redacted] for Trenton 6 arrives at the plant by truck. [redacted] weighs the coal at its premises on its certified truck scale and sends a weigh bill with every truck. The Trenton plant has a certified truck scale and randomly weighs a sample of trucks once or twice a week to ensure that the weights on the weigh bills are accurate. Trenton enters the weights using the weight of each individual railcar. Domestic coal weights are recorded by entering the individual day's weight and confirming with the supplier that the total matches the Aligne entry. As discussed in the chapter on Solid Fuel Procurement, [redacted]

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1 Point Tupper Marine Terminal has a berthing capacity which could accommodate a vessel of 150,000 to 160,000 metric tons and a capacity to store up to 140,000 metric tons of solid fuel.

[redacted]. We address this in section 8 below.

V.B.1.f. Plant-Specific Information: Point Tupper

Like Trenton 5, 100% of Point Tupper's solid fuel was imported during the Audit Period. All imported coal deliveries for Point Tupper are made by vessel directly to the Point Tupper Marine Terminal, which is located next to the plant. The coal for Point Tupper consumption is pushed into the plant reclaim feeders and then falls on the plant feed conveyor belt. A belt scale on the plant feed conveyor belt measures the total weight of the coal carried by the belt into the plant bunkers. These measurements are read daily by the Point Tupper Operations Superintendent and entered into Aligne. Aligne is updated for coal received by creating transfer shipments for the amounts, taken from the belt scale.

Like the contract with [redacted] at the International Pier, NSPI's contract with [redacted] was premised upon assumptions of total volume of solid fuel to be handled; in this case, [redacted]. Notably, [redacted].

V.B.1.g. FAM Cost of Point Tupper Marine Terminal, International Pier

All fuel handling costs at the International Pier and Point Tupper Marine Terminal are recovered through the FAM. In 2016 and 2017, FAM-recoverable fuel handling costs at the International Pier totalled [redacted] and [redacted], respectively. These costs were payable to [redacted]. At the Point Tupper Marine Terminal, fuel handling costs were [redacted] in 2016 and [redacted] in 2017, payable to [redacted]. Drawing comparisons between the two terminals is not simple, since the volumes of solid fuel handled at the International Pier are much greater than at the Point Tupper Marine Terminal, and the services provided by [redacted] include both railcar and truck transport to Lingan and Point Aconi, while [redacted] only loads railcars; leasing and transport are provided by other venders (e.g., [redacted] and [redacted]).

Capital expenditures related to the two terminals are not recovered through FAM but through the fixed cost recovery portion of rates. Given that NSPI owns both marine terminals, NSPI is ultimately responsible for capital investments. One significant capital investment at Point Tupper Marine Terminal during the Audit Period was the $467,607 replacement of the conveyor belt that hauls in coal from the dock.[2] More capital expenditures at Point Tupper Marine Terminal may be required in the coming period; two of its external consultants recommended that NSPI consider capital expenditures at the Marine

[2] Other capital investments included in the 2017 plan totaled $267,366.

Terminal. [redacted] recommends expansion of Point Tupper Marine Terminal's railcar loading and storage capacity at a cost of [redacted], combined—see section 8 below—while [redacted], which was hired to study options for improving coal pile stability at the Marine Terminal following a heavy rain event in October 2016 that resulted in coal being spilled into the Strait of Canso, offered in a June 29, 2017, report a menu of options to improve pile stability, including building a retaining wall; the costs of these options were estimated to be between $0.1 million and $1.2 million. NSPI reports that it built the retaining wall at Point Tupper Marine Terminal in the fall of 2017 for a cost of $216,659.82. (We discuss the coal spill into the Strait of Canso in detail in section 6 below.) [redacted] also studied a potential expansion of Point Tupper Marine Terminal, issuing a September 2016 report that assessed three potential options for expansion of the terminal; the cost of the options ranged from [redacted].

V.B.2. Quantity and Quality Control of Solid Fuel

NSPI's solid fuel supply contracts—discussed in the Solid Fuel Procurement Chapter —contain a myriad of quantity and quality technical specifications that suppliers must meet in providing solid fuel. Determining whether the solid fuel meets those specifications is a crucial aspect of solid fuel supply management. For NSPI, this is not a simple task; much of its solid fuel is imported internationally, meaning that it must find ways to ensure adequate quantity and quality of its shipments, despite the distance between NSPI and the solid fuel sources on which it relies. This section explains the adequate processes NSPI has in place for testing the quantity and quality of its solid fuel supply, which are contained in NSPI's Fuel Manual. As we explain below, NSPI has quality control in place both at the loading ports, the receiving ports, as well as at NSPI's generating plants.

V.B.2.a. Imported Solid Fuel

As per the Fuel Manual, NSPI has engaged independent load port representatives acting on NSPI's behalf to witness the loading and sampling of each vessel at the load ports to ensure that established ASTM procedures are being followed for the collection of the transactional sample. The load port representative—currently [redacted]—provides a series of services related to NSPI solid fuel shipments at the loading port, including inspection of the cargo holds and condition of the vessel, observation of the coal loading operation, review of belt scale calibrations, and verification of the quantity of water added to the shipment for dust control. [redacted] offers its services at several ports, including those used by NSPI in Colombia and in the United States.

[redacted] oversees that the transactional sample is split and analyzed by two other independent labs (one commissioned by the load port representative and one local lab commissioned by NSPI—i.e., [redacted][3]). NSPI selects six to eight of these samples annually for analysis by [redacted] and does not allow the unloading of cargoes to commence unless it has received the transactional analysis of the cargo from the supplier and has confirmed that this analysis is in compliance with the quality specifications in the

[3] NSPI Fuel Manual Version 10, "Solid Fuel Procurement Quality Assurance for Sampling and Analysis."

purchase agreement. NSPI logs the disport terminal belt scale readings on each cargo unloading and compares it to the transactional draft survey. These analyses are in addition to the transactional analysis that the supplier's lab carries out. Draft surveys are conducted by an independent third party contracted by the supplier; these draft surveys determine the cargo quantity and, consistent with the Fuel Manual,[4] it is this quantity determined by the draft survey that is recorded on the Bill of Lading.

Once this process is complete, the Coal Procurement and Logistics Specialist receives invoices via email and/or by courier and receives the report from the supplier's independent lab and the draft survey. [redacted] also sends a report that verifies the draft survey result and that proper procedures were followed in loading the vessel. The Bill of Lading, which contains the draft survey result, is endorsed by the authorized vessel representative. The NSPI Logistics Administrator uses the draft survey information from the Bill of Lading to enter the shipment volume into Aligne.

Upon the coal's arrival at either the International Pier or the Point Tupper Marine Terminal, NSPI verifies the transactional data related to the shipment to the contract specifications; if there is a concern, NSPI is not obligated to accept the shipment. In some cases, NSPI has outright rejection rights but more often than not will negotiate a price adjustment under the contract. In any event, in these cases, [redacted] an important protection that provides suppliers and shippers incentive to deliver the quantity and quality of solid fuel found in the technical specifications of the contract. NSPI's contractor ([redacted] in the former case, [redacted] in the latter) weighs the coal using a belt scale on the in-haul conveyor from the dock and then provides NSPI with a report. The contractor is required to calibrate the scales when necessary.

Solid Fuel invoices are received against the purchase orders approved and set up by FERM. Oracle is configured so that fuel purchases are accrued upon receipt if matched to a purchase order. Activities against a shipment that result in charges being posted will automatically post transactions to the inventory and payable ledgers in Aligne, as well as generate the general ledger transactions for the appropriate accounts through the month-end interface between Aligne and Oracle.

V.B.2.b. Domestic Solid Fuel

Coal delivered by domestic coal suppliers to Trenton 6 is manually sampled on a daily basis, according to ASTM standards. The daily samples are used to prepare a weekly composite sample, which is analyzed to provide the transactional analysis. The Trenton lab conducts the weekly transactional analysis. A split of these weekly samples is sent to [redacted] and samples are randomly selected for backup testing and comparison to the Trenton lab analysis. In addition, [redacted] visits the Trenton site four to six times per year and independently samples the trucks as they arrive, while observing the transactional sampling of the trucks. This independent sample is then analyzed by [redacted], and the results are compared to the transactional sample analyzed by the Trenton lab. The independent lab also

[4] NSPI Fuel Manual Version 10, "Solid Fuel Procurement Quality Assurance for Sampling and Analysis."

audits the sample preparation of the daily and weekly samples at the lab on an annual basis. The domestic coal is weighed using a certified truck scale at the source mine. The Trenton plant does random check weights weekly on truckloads of domestic coal as it arrives at the site.

Because NSPI does not have a long-term agreement in place for [redacted] coal, and because the [redacted] is in its early days of operation, NSPI's approach to quality testing of [redacted] coal has differed from its approach to Trenton's domestic supply. NSPI has tested both [redacted] coal during the Audit Period. In NSPI's first agreement with [redacted], NSPI received weekly testing samples. After the [redacted] in September 2017, NSPI's second agreement with [redacted] for [redacted] coal also called for weekly sample testing, which NSPI noted would continue over the "next several months." NSPI also tested [redacted] coal as a potential adder fuel at Point Aconi; for this, NSPI contracted with [redacted] to test the chemical suitability of [redacted] coal as part of a combustible blend in the unique circulating fluidized bed design of the Point Aconi unit. Ultimately, [redacted].

V.B.2.c. Quality and Quantity Control at NSPI's Plants

With the exception of Point Tupper, the plants have certified truck scales, which weigh the incoming deliveries; Point Aconi, for example, uses an on-site scale for all shipments. For Trenton 6's imported supply—which arrives by rail—weighing is done at the Point Tupper Marine Terminal, while plant personnel verify the arrival of the railcars in each delivery, entering the information manually into Aligne. (A similar approach is taken at Lingan for solid fuel arriving by rail.)

The plants have various feeders, metres, and measurement systems to determine the accurate quantity of solid fuel entering the plant for combustion. The measurements taken by the feeders/meters occur as solid fuel is consumed. Measurement equipment is subject to scheduled calibrations at least twice per year to ensure they are automatically fed into the Process Information (PI) system. The consumption information from PI is then fed into Aligne. The Operations Superintendent for each of the plants enters the solid fuel blend ratios—which are provided by FERM—into Aligne. Aligne then divides the overall daily consumption as reported by PI into the various types of solid fuels based on the blend ratios specified. The Operations Superintendent reviews the calculated consumption figures in Aligne and confirms or manually adjusts if required. As part of the month-end close process, the Financial Analyst performs a reconciliation between the consumption as reported by PI and consumption recorded in Aligne, noting any variances. At month end, consumption figures are reviewed by the Manager Fuels Accounting and Reporting for completeness and reasonability.

Testing of solid fuel is done frequently and both on-site (at NSPI plant labs) and by an independent third-party ([redacted]). At Lingan, for example, samples are tested three times per week at the plant laboratory for various quality metrics, including ash, btu, and Sulphur content. NSPI also sends weekly samples to [redacted] for independent testing.

V.B.2.d. Biomass

NSPI receives all biomass deliveries to the Port Hawkesbury plant by truck. Upon arrival, deliveries are weighed using WeighWiz, which is a commercially available weigh scale system for truck deliveries. Trucks are weighed as they enter the plant (with a full cargo) and as they exit (empty), with the delta being recorded as the weight of the delivery.[5] As noted above, the weight and delivery data are automatically transferred to LIMS and compared against vender invoices on a weekly basis by the Senior Contract Administrator of biomass. When the vender invoices are received, the delivery information is entered into Aligne.

The biomass plant has two truck dumpers—one for primary biomass fuel (wood chips) and another for secondary fuel (bark). Like the other solid fuel plants, FERM determines the optimal fuel blend, and the plant personnel are responsible for blending the fuels.

During the Audit Period, quality testing of the biomass was done at the plant and offsite by [redacted]. As part of its services agreement with NSPI, [redacted] collects and analyses quality samples of biomass onsite for moisture content, fuel sizing, fuel type, and fuel quality. (Evidence of the success of this testing process is below in section 4.) On a monthly basis, samples are also sent to [redacted] for testing of a variety of quality metrics, which are done in compliance with ASTM standards.[6] This is a particularly important quality check, since [redacted] is now both NSPI's biomass fuel supplier *and* its quality assurance tester under its separate services agreement.

V.B.3. **Solid Fuel Contract Administration**

NSPI's solid fuel contract administration is under the direction of the Senior Manager of Fuels Strategy and Performance. The Senior Manager's team includes the Coal Procurement and Logistics Specialist, who conducts the daily administration of international fuel contracts—i.e., overseeing contracts for shipping solid fuel supply from international mines to Nova Scotia—including regularly inputting fuel information into NSPI's vessel schedule, monitoring the status of international shipments, and monitoring the fuel shipments for quality and quantity. A third team member—the Senior Contract Administrator—is responsible for the solid fuel supply once it reaches Nova Scotia, managing the inventory at both the International Pier and Point Tupper Marine Terminal, as well as at NSPI's generating stations. A fourth team member—the Logistics Administrator—inputs information from the vessel schedule into Aligne.

Both the Coal Procurement and Logistics Specialist and the Senior Contract Administrator conduct regular site visits throughout the year. The Coal Procurement and Logistics Specialist visits both the Point Tupper Marine Terminal and International Pier at least once annually, and also visits coal mines that supply NSPI's fuel. The Senior Contract Administrator, who maintains a primary office in the field in Sydney, Nova Scotia, regularly visits each generating station site and the two unloading port sites on an

[5] NSPI Fuel Manual, "Biomass Procurement Quality Assurance for Sampling and Analysis."

[6] NSPI Fuel Manual, "Biomass Procurement Quality Assurance for Sampling and Analysis."

as-needed basis and meets with [redacted] and [redacted] four times per year at minimum. The Logistics Administrator reports to the Senior Contract Administrator and participates in these meetings. Figure V-1 shows all coal mine site visits conducted by NSPI personnel during the Audit Period.

Figure V-1. NSPI's Audit Period Site Visits to Coal Mines

Date	Mine	Location	Supplier
April 26, 2016	[redacted]		
July 11, 2016			
October 6, 2016			
November 18, 2016			
March 1, 2017			
March 13, 2017			
June 5, 2017			
October 4, 2017			
November 2, 2017			
March 20–21, 2017			
March 20–21, 2017			
March 20–21, 2017			

NSPI also uses a Senior Contract Administrator for Biomass, who maintains his primary office in the field at the PHP biomass plant and has responsibility for field contract administration activities associated with biomass supply. His primary activities focus on management of the biomass supply contracts and securing adequate biomass inventory. Additional responsibilities include invoice processing and verification of all related information on quality and quantity for biomass received, as well as input of certain data into Aligne.

NSPI's solid fuel contract administration staff regularly participate in scheduled meetings and calls that help support their administration function. These include:

- **Morning Call:** NSPI's daily morning meeting—discussed in more detail in our chapter on Economic Commitment and Dispatch—includes regular participation by the Coal Logistics and Procurement Specialist and others involved in solid fuel contract administration.
- **Fuels Leadership Meeting:** As a new initiative, the Director of Fuels holds a bi-weekly meeting with his direct reports to share status updates on priority items.
- **Quarterly FERM Team Meeting:** Previously held on a monthly basis, these department-wide meetings cover topics such as policy changes and FERM initiative status updates. NSPI decided to hold these meetings less frequently because they were viewed by employees as having little productive benefit while imposing constraints on

schedules. NSPI also distributes some information by email FERM-wide that would have been discussed at a monthly meeting.

- **Weekly Vessel Scheduling Meeting**: Led by the Coal Procurement and Logistics Specialist. This meeting includes representation from both [redacted] and [redacted]
- **Weekly Inventory Meeting:** This meeting, led by the Senior Contract Administrator, includes representatives from each of NSPI's generating stations.
- **Bi-Weekly Inventory Meeting:** A bi-weekly inventory meeting is also held that is chaired by the Coal Procurement and Logistics Specialist, who holds this bi-weekly meeting to review the health of the inventory at the ports and generation station sites with the Director, Fuels; the Senior Manager, Fuels Strategy and Performance; and the Commercial Manager, Fuels. In addition, bi-weekly conference calls are held with the Senior Manager of FERM and the Senior Contract Administrator and Logistics Specialist to discuss status updates on work items related to their field activities, contract administration, and associated administrative work.
- **Coordination Meetings:** Led by the Director of Fuels, these meetings include members of the energy marketing desk, the oil and gas desk, and the solid fuel team for the purposes of discussing key trends and issues affecting prices.
- **Outage Coordination Meetings:** These weekly meetings—chaired by Energy Control Centre (ECC) personnel—are intended to coordinate transmission and generation outages and include representatives from FERM and solid fuel contract administration.

V.B.4. Contract Compliance

V.B.4.a. Contract Quantities

Each of NSPI's coal and petcoke contracts calls for a contract quantity, with a tolerance of some percentage that can be delivered above and below the contracted quantity. From these numbers, it is simple to determine the minimum and maximum quantities under each contract. It is important that NSPI generally observes that actual quantities delivered under its agreements fall within this minimum-maximum range, since that range represents NSPI's expected solid fuel needs. NSPI's coal supply contracts contain recourse in the event the supplier fails to meet specified quantity requirements. Failure to meet technical specifications is managed through rejection rights or forms of compensation specified in the supply contract. It is common that in lieu of physically rejecting a vessel from unloading, NSPI will negotiate compensation prior to the vessel being permitted to unload. Failure to meet quantity requirements is managed through seller's deficiency stipulations in the supply contract and/or compensatory settlement agreements.

Figure V-2 and Figure V-3 demonstrate that during the Audit Period, NSPI's contracted suppliers generally performed [redacted]. In [redacted] instances, sellers provided more solid fuel than the maximum; of those, [redacted] were of material difference. In one case—that of [redacted]

[redacted], which over-delivered by [redacted]—the shipper ([redacted] substituted another of its vessels to accommodate the cargo lift from the damaged vessel; that replacement vessel was larger than the original, leading to the overage. In [redacted] instances did suppliers fail to meet minimum delivery requirements.

Figure V-2. NSPI's 2016 Solid Fuel Contract Deliveries (All Data in Metric Tonnes)

Counterparty	Product	Quantity Received	Contract Minimum	Contract Maximum	Amount Over/(Under)
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	PC	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	PC	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	PC	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	PRB	[redacted]	[redacted]	[redacted]	[redacted]

Figure V-3. NSPI's 2017 Solid Fuel Contract Deliveries (All Data in Metric Tonnes)

Counterparty	Product	Quantity Received	Contract Minimum	Contract Maximum	Amount Over/(Under)
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	MS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	LS	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	PC	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Regarding biomass deliveries, NSPI's supply contracts with [redacted] and [redacted], which were terminated in 2016 as discussed above, specified minimum volumes. The contract for standby biomass supply with [redacted], which was signed following the change to economic dispatch, specifies targets for standby supply volumes. Figure V-4 and Figure V-5 show all deliveries received during the Audit Period; note that the sharp dropoff in biomass deliveries was driven by the province's declaration that the biomass plant was no longer to be run as a must-run unit.

Figure V-4. NSPI's 2016 Biomass Contract Deliveries (All Data in Metric Tonnes)

Counterparty	Product	Quantity Received	Contract Minimum	Contract Maximum	Amount Over/(Under)
[redacted]	Roundwood	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Chips	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Bark	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Roundwood	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Chips	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Bark	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Roundwood	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Chips	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	Bark	[redacted]	[redacted]	[redacted]	[redacted]

Figure V-5. NSPI's 2017 Biomass Contract Deliveries (All Data in Metric Tonnes)

Counterparty	Product	Quantity Received	Contract Minimum	Contract Maximum	Amount Over/(Under)
[redacted]	Roundwood	[redacted]	[redacted]	None	[redacted]
[redacted]	Chips	[redacted]	[redacted]	None	[redacted]
[redacted]	Bark	[redacted]	[redacted]	None	[redacted]

V.B.4.b. Contract Quality

NSPI's coal supply contracts also contain recourse in the event the supplier fails to meet specified requirements for quality. Failure to meet technical specifications is managed through rejection rights or forms of compensation specified in the supply contract. It is common that in lieu of physically rejecting a vessel from unloading, NSPI will negotiate compensation prior to the vessel being permitted to unload. For domestic coal contracts, NSPI has delivery suspension rights as well as compensatory quality adjustments. For biomass, NSPI may suspend shipments if quality is not acceptable.

During the Audit Period, there were no instances of suppliers of coal or petcoke failing to meet their contractual obligations for quality.

In the first quarter of 2016, NSPI identified issues with moisture content above the maximum allowance in its secondary fuel (bark) supply contracts with each of its three suppliers. In response, NSPI instructed its three biomass suppliers to suspend their deliveries from specific bark sources due to bark moisture content not meeting contract specification. The instruction was issued to the following suppliers:

- [redacted] on January 12, 2016. Deliveries were not resumed, as the delivery tonnage was nearly fulfilled at the time of the suspension.
- [redacted] on February 3, 2016. Deliveries were resumed February 24, 2016, when the biomass met the applicable moisture specification.
- [redacted] on February 11, 2016. Deliveries were resumed March 1, 2016, when the biomass met the applicable moisture specification.

NSPI did not need to replace the bark in these instances, as inventories were sufficient to support dispatch.

V.B.4.c. Bates White's Contract Administration Samples

We sampled several coal deliveries during the Audit Period to check NSPI's contract administration results. Specifically, we examined (1) the underlying confirmation agreement stipulating the quantities to be delivered over a given time period, (2) the quantity and quality test results for a given delivery, and (3) the final invoice issued to NSPI for the solid fuel. In all cases, we confirmed that NSPI was properly invoiced for the correct quantity of solid fuel and that any price adjustments called for in the underlying confirmation agreement related to quantity or quality deviations were accurately calculated and applied.

V.B.5. Solid Fuel Inventory

V.B.5.a. NSPI's Approach

NSPI's approach to inventory management is a reasonable one: it defines a governing principle, a series of targets that guide NSPI, and a series of thresholds that, if breached, require specific action. NSPI's approach—which is contained in its Fuel Manual—is sufficiently specific to ensure NSPI personnel understand relevant protocols, while allowing for flexibility in managing inventory to meet specified targets. In other words, the Fuel Manual factors in the cost of inventory building and does not prioritize inventory target levels above the relative cost of building them.

NSPI's governing principle is to have sufficient staple fuels—i.e., primary, core fuels needed to support the plant's loading requirements—to meet its peak demand season, which is the winter months: January, February, and March. NSPI describes this approach as "winter readiness" and seeks to meet its inventory targets by December. This approach is appropriately codified in the Fuel Manual and includes a sufficient explanation regarding why this approach is taken: specifically, because NSPI's experience has shown that inventories can be depleted quickly when plants are running at full load and there are greater risks in the transportation of solid fuel during the winter months that could delay deliveries.[7]

[7] NSPI Fuel Manual Revision 10, Link 7 "FERM Solid Fuel Inventory Management Process."

The targets associated with winter readiness are based on operating the plants at full load, 24 hours a day, for the entire winter (i.e., 11 weeks). Fleetwide, that translates to between [redacted] MTs. Throughout the year, and in making delivery and contracting decisions, NSPI monitors its inventory positions and looks at updated forecasts of expected consumption in building a sufficient winter-ready inventory of solid fuel.

Looking more granularly at NSPI's inventory targets, NSPI breaks its inventory positions into two general "circuits": the Point Tupper Circuit and the Sydney Circuit. The Point Tupper Circuit includes (1) Trenton 5's coal pile, (2) Trenton 6's coal pile, (3) the Point Tupper Marine Terminal coal piles, and (4) the Bear's Head coal storage piles located adjacent to the Point Tupper Marine Terminal. The Sydney Circuit includes (1) the Lingan coal pile, (2) the Lingan long-term "dead" storage coal pile, (3) Point Aconi's petcoke/coal pile, and (4) the International Pier coal piles. Figure V-6 shows NSPI's target inventory levels by circuit and storage pile to achieve winter readiness.[8]

Figure V-6. NSPI's Approximate Winter Readiness Inventory Targets (All Data in Metric Tonnes)

Inventory Location	Circuit	Amount	Solid Fuel Type
Trenton 5	Point Tupper	[redacted]	Imported Coal
Trenton 6	Point Tupper		Imported Coal Domestic Coal
Point Tupper Marine Terminal and Bearhead	Point Tupper		Imported Coal/ Petcoke
Total Point Tupper Circuit			
Lingan (Live and Dead Storage)	Sydney		Imported Coal
Point Aconi	Sydney		Petcoke/Coal
International Pier	Sydney		Imported Coal/Petcoke
Total Sydney Circuit			
Total NSPI Fleetwide			

NSPI also aims to minimize inventories of adder fuels—i.e., inferior fuels unable to support plant loading requirements but used in blending to provide economic benefits—entering the winter months because they crowd out space for staple fuels and increase the possibility of double handling of fuels.[9]

Besides these fleetwide and plant specific targets, NSPI defines minimum and maximum inventory guardrails that, if breached, trigger specific action. That is, if levels reach as high as 13 weeks at maximum consumption or as low as 4 weeks at current consumption for a 30-day period, the Coal Procurement and Logistics Specialist is required to develop and provide a corrective plan to the Senior Manager and Director of FERM. That plan may include purchasing additional vessels of fuel (if below inventory) or maintaining current inventory levels due to economics.[10]

8 Note that the actual targeted inventory amounts can vary due to changes in consumption forecasts. Figure V-6 provides a reasonable approximation of those targets.

9 NSPI Fuel Manual Revision 10, Link 7 "FERM Solid Fuel Inventory Management Process."

10 NSPI Fuel Manual Revision 10, Link 7 "FERM Solid Fuel Inventory Management Process."

In a positive change from previous Audit Periods, the Fuel Manual now contains an inventory management process for biomass fuel.[11] Fuel is initially drawn from a standby inventory kept available for periodic economic dispatch of the plant. The amount of biomass stored is limited to volumes that can be tarped, kept in roundwood form, or consumed over short periods to avoid weather degradation. Based on experience, FERM estimates the standby inventory should contain in the range of [redacted] MT consisting of roundwood, fresh forest chips, and bark.[12]

V.B.5.b. Audit Period Results

NSPI's actual inventories are provided in the following set of figures. We begin with 2016: Figure V-7 and Figure V-8 show solid fuel inventory, by month, at the two NSPI circuits for 2016. Figure V-9 provides NSPI's overall inventory amounts, by month, in 2016.

Figure V-7. 2016 Solid Fuel Inventory at the Point Tupper Circuit (Metric Tonnes)

[redacted]

[11] NSPI Fuel Manual Revision 10, Link 7 "FERM Solid Fuel Inventory Management Process."

[12] NSPI Fuel Manual Revision 10, Link 7 "FERM Solid Fuel Inventory Management Process."

Figure V-8. 2016 Solid Fuel Inventory at the Sydney Circuit (Metric Tonnes)

[redacted]

Figure V-9. 2016 Solid Fuel Inventory (NSPI Total Metric Tonnes)[13]

[redacted]

As shown in the figures above, NSPI did not achieve its target solid fuel inventory for winter readiness by the end of December. Figure V-9 shows that NSPI's total year-end solid fuel inventory of

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[redacted] MTs was [redacted] metric tons—or about [redacted]—below its year-end target of [redacted] MTs. NSPI explained that the primary driver of this shortfall was a delay in three solid fuel shipments schedule for Q4: two mid-sulphur shipments ([redacted] MTs each) and one cargo of petcoke ([redacted] MTs). Had these shipments arrived as scheduled, NSPI would have had just below its target of [redacted] MTs. Moreover, as of November 4, 2016—before the delayed petcoke shipment and one of the two delayed mid-sulphur shipments were known—NSPI's end-of-year inventory projection was [redacted] MTs, which was sufficient to cover 11 weeks of uninterrupted burn by its thermal fleet.

Below, following our discussion of the 2017 inventory results, we provide our analysis of NSPI's year-end target, contained in its Fuel Manual. Focusing on 2016 only, we find NSPI's approach to inventory management reasonable. NSPI properly scheduled sufficient cargos to be within a reasonable range of its year-end inventory target for winter readiness. The delayed shipments were not the fault of NSPI, and though the delays resulted in a lower inventory supply for the winter period, NSPI still had enough inventory to cover about 60 days of solid fuel for its fleet, running around the clock at full load.

We note, too, that NSPI addressed the delayed shipments reasonably. To shore up inventories, NSPI procured an additional shipment of [redacted] MTs of mid-sulphur coal in December 2016 from [redacted] at a reasonable price [redacted]/MT), consistent with market conditions and below indicative offers from [redacted] other suppliers. The two delayed mid-sulphur shipments were rescheduled for January 2017, as was the petcoke shipment. NSPI's contracts with suppliers contain protections against delays in shipments, such as those endured in the fourth quarter of 2016. For example, in the case of the delayed petcoke shipment by [redacted], NSPI negotiated a settlement in which [redacted] would deliver the delayed shipment of petcoke in January 2017 for the same price, plus an extra [redacted] MTs, while the two delayed mid-sulphur deliveries from [redacted] were rescheduled for January and February of 2017.[14]

Turning to 2017, Figure V-10 and Figure V-11 show solid fuel inventory, by month, at the two NSPI circuits for 2017. Figure V-12 provides NSPI's overall inventory amounts, by month, in 2017.

[14] We note that it does not appear to us that the [redacted] shipment "delays" actually violated the confirmation agreement with [redacted] since, in section 4, the confirmation agreement specifies two mid-sulphur shipments to be delivered "December 2016 through January 2017 unless otherwise mutually agreed by the Parties."

Figure V-10. 2017 Solid Fuel Inventory at the Point Tupper Circuit (Metric Tonnes)

[redacted]

Figure V-11. 2017 Solid Fuel Inventory at the Sydney Circuit (Metric Tonnes)

[redacted]

Figure V-12. 2017 Solid Fuel Inventory (NSPI Total Metric Tonnes)[15]

[redacted]

As with 2017, NSPI again fell short of its end-of-year inventory target. This time, as shown in Figure V-12, the shortfall equaled [redacted] MTs, which was about [redacted] below the target. This time, NSPI explained that both higher-than-forecasted solid fuel consumption during the quarter and a number of supply disruptions. Those disruptions included a delay of deliveries from [redacted] due to a mine slope failure, from [redacted] due to heavy berth congestion and lack of vessel availability, and from [redacted] due to extreme weather. In total, these supply disruptions contributed about [redacted] MTs to the inventory shortfall relative to the target. In addition, NSPI had attempted to contract with a new supplier—[redacted] (later renamed [redacted])—but that the supplier proved to be too risky, as discovered during NSPI's due diligence. [redacted] was scheduled to provide [redacted] MTs of low-sulphur coal in the fourth quarter of 2017 after being selected in a competitive RFP for low-sulphur coal issued by NSPI in March 2017.

The delayed shipments were not the fault of NSPI, and though the delays resulted in a lower inventory supply entering the winter period, NSPI still had enough inventory to cover about 50 days of solid fuel for its fleet, running around the clock at full load. NSPI appropriately rescheduled (and received) all delayed shipments in January 2018. It should also be noted that going into the fourth quarter of 2017, NSPI was forecasted to have [redacted] MTs of solid fuel by the end of year, which left a difference of about [redacted] MTs between its forecasted position and the end-of-year target heading into the fourth quarter. Upon determining that [redacted] would not be a reliable supplier, and upon a portfolio review that demonstrated sufficient low-sulphur supply and a need for additional mid-sulphur coal, NSPI again properly scheduled sufficient cargos to be within a reasonable range of its year-end inventory target for winter readiness. NSPI could have procured more supply; however, we believe it was reasonable that NSPI did not attempt to replace all the forecasted shortfall of solid fuel since doing so could have resulted in high prices for such last-minute deliveries. Instead, NSPI reasonably [redacted] and purchased a cargo of mid-sulphur coal from

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the same counterparty for fourth quarter 2017 delivery. (We discussed this procurement in the Solid Fuel Procurement chapter.)

Stepping back and underscoring the point that we think NSPI acted reasonably during the Audit Period related to its solid fuel inventory management, it also appears to us that the Fuel Manual's "target" winter readiness supply (equal to an amount that would support the entire solid fuel fleet operating at full load for 11 weeks) may become excessive at some point in the future. As we demonstrate in other chapters of this report, NSPI's coal- and petcoke-fired generators are operating at lower capacity factors than ever, and coal-fired generation is providing less and less of NSPI's generation each year, a trend forecasted to continue. NSPI has asserted that, given its peak load forecasts and planning reserve margins, each coal- and petcoke-fired generator is needed for its capacity—and we agree. However, we also agree with NSPI that the amount of *energy* being provided by those units continues to shrink with the increased penetration of wind. Given that fact, it would make sense that, over time, solid fuel inventory targets would eventually decrease accordingly.

We note that, at least since 2015, NSPI's target winter readiness inventories have not changed.[16] Yet capacity factors have continued to fall, even during the winter months. Figure V-13 shows the percentage of hours during the winter months—January, February, and March—in which NSPI's individual coal- and petcoke-fired generating units operated at 145 MW or higher. Note that we have selected a conservative loading amount, evidenced in two ways; the generation data we used represented "gross" generation, not "net" generation, meaning that station power was included in the gross generation number, and all the units in NSPI's fleet shown in Table V-7 have capacities of at least 150 MW. Thus, our table surely overstates the hours in which these generators are operating at "full load"—which is NSPI's standard assumption for planning to have 11 weeks of solid fuel inventory at the end of the year to get ready for the winter months.

Figure V-13. Percentage of Hours Operating at 145 MW Higher in Winter Months

Plant	2016	2017
Lingan 1	14	24
Lingan 2	9	21
Lingan 3	27	37
Lingan 4	23	35
Point Aconi	81	83
Point Tupper	46	58
Trenton 5	50	56
Trenton 6	78	82

Another way we assessed NSPI's inventory targets was to look more specifically at NSPI's results across the two circuits. As shown in Figure V-13, the Point Tupper circuit—which includes the Trenton and Point Tupper stations—seem to have operated at near-full load more often than the units on the

16 See NSPI Fuel Manual, Revision 8, Link 7.

Sydney circuit. We note, then, that during the Audit Period, at the end of each December, NSPI was much closer to its winter readiness targets at the Point Tupper circuit than the Sydney circuit. Specifically, the Point Tupper circuit was just 0.4% and 10.6% below winter readiness targets at the end of December 2016 and 2017, respectively, while at the Sydney circuit, inventory was 25.9% and 46.3%, respectively, from targets.

Figure V-14. Solid Fuel Inventory at Point Tupper, Sydney Circuits at end of December 2016, 2017

Circuit	Point Tupper Circuit	Sydney Circuit
2016 Target (metric tons)	[redacted]	
2016 Actual (metric tons)		
2016 Shortfall (metric tons)		
2016 Below Target—December 31 (%)		
2017 Target (metric tons)		
2017 Actual (metric tons)		
2017 Shortfall (metric tons)		
2017 Below Target—December 31 (%)		

Our finding here is that NSPI's inventory targets may become excessive at some point in the future. That may be especially true at the Sydney circuit, given the results in Figure V-14 and above (due to circumstances beyond its control), with no observable negative consequences for fuel reliability. We make no recommendation on this finding, as we discussed this issue with NSPI personnel and found that they assess their winter readiness targets and results regularly and would expect that if the need arose to reduce their winter readiness targets, they would appropriately assess the issue at that time. Moreover, it is important to note that while NSPI did not meet its winter readiness targets on December 31, it did have significant deliveries scheduled for January and February, as explained above.

Regarding biomass inventories, Figure V-15 below shows the dramatic change in biomass inventories held at PHP in response to the change in provincial designation of the biomass unit. That is, at the beginning of the Audit Period, NSPI had a biomass inventory of almost [redacted] green MTs of biomass fuel; by the end of the Audit Period, inventory had been reduced to just over [redacted] green MTs. This was an appropriate response by NSPI, as the biomass unit was expected to be run far less as an economic unit.

Figure V-15. Biomass Fuel Inventory at Port Hawkesbury, by Month (Green Metric Tonnes)

[redacted]

V.B.6. Physical Inventory Measurement and Adjustment

Per the Fuel Manual, plant management is responsible for solid fuel inventory supplies at the plants, while FERM is responsible for monitoring inventories at Point Tupper Marine Terminal and International Pier.[17] On a quarterly basis, FERM is responsible for surveying the solid fuel inventories, including those stockpiled at the individual plants. Biomass piles are surveyed quarterly. The Fuel Manual contains both the methodology to be employed in the inventory survey, the thresholds that require corrective inventory adjustment actions, and the financial procedures that are to be taken to initiate those adjustments.

Specifically, if the physical survey for a given coal quality and commodity (e.g., low-sulphur, low Btu coal) is less than 95% or greater than 105% of NSPI's book inventory for two successive quarters, then NSPI adjusts the book inventory for the repeating portion of the variance.[18] In other words, NSPI would make an adjustment equal to the lesser of the two quarterly variances and would never adjust inventory if physical inventory is within 5% of book inventory. Adjustments to book inventory levels are made by either increasing or decreasing the recorded consumption from the affected inventory location.

17 Fuel Manual Revision 10, section 12.

18 Fuel Manual Revision 10, Appendix M.

For example, when the book inventory needs to be increased, consumption would be decreased in Aligne to accomplish this. To decrease book inventory in Aligne, consumption would be increased.

The following several tables (Figure V-16 – Figure V-22) show the inventory adjustments by plant or marine terminal, by quarter, with the exception of the PHP biomass plant, which sees only annual adjustments.

Figure V-16. Lingan Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	PRB	Domestic	LT LSH
Q1 2016 (metric tons)	[redacted]						
Q1 2016 ($)							
Q2 2016 (metric tons)							
Q2 2016 ($)							
Q3 2016 (metric tons)							
Q3 2016 ($)							
Q4 2016 (metric tons)							
Q4 2016 ($)							
Q1 2017 (metric tons)							
Q1 2017 ($)							
Q2 2017 (metric tons)							
Q2 2017 ($)							
Q3 2017 (metric tons)							
Q3 2017 ($)							
Q4 2017 (metric tons)							
Q4 2017 ($)							

Figure V-17. International Pier Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	PRB	Domestic	LT LSH
Q1 2016 (metric tons)	[redacted]						
Q1 2016 ($)							
Q2 2016 (metric tons)							
Q2 2016 ($)							
Q3 2016 (metric tons)							
Q3 2016 ($)							
Q4 2016 (metric tons)							
Q4 2016 ($)							
Q1 2017 (metric tons)							
Q1 2017 ($)							
Q2 2017 (metric tons)							
Q2 2017 ($)							
Q3 2017 (metric tons)							
Q3 2017 ($)							
Q4 2017 (metric tons)							
Q4 2017 ($)							

Figure V-18. Point Tupper Marine Terminal and Bear's Head Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	PRB	Domestic	LT LSH
Q1 2016 (metric tons)	[redacted]						
Q1 2016 ($)	[redacted]						
Q2 2016 (metric tons)	[redacted]						
Q2 2016 ($)	[redacted]						
Q3 2016 (metric tons)	[redacted]						
Q3 2016 ($)	[redacted]						
Q4 2016 (metric tons)	[redacted]						
Q4 2016 ($)	[redacted]						
Q1 2017 (metric tons)	[redacted]						
Q1 2017 ($)	[redacted]						
Q2 2017 (metric tons)	[redacted]						
Q2 2017 ($)	[redacted]						
Q3 2017 (metric tons)	[redacted]						
Q3 2017 ($)	[redacted]						
Q4 2017 (metric tons)	[redacted]						
Q4 2017 ($)	[redacted]						

Figure V-19. Point Aconi Inventory Adjustments

Adjustments	LSH	LSL	MS	Petcoke	PRB	Domestic	LT LSH
Q1 2016 (metric tons)	[redacted]						
Q1 2016 ($)	[redacted]						
Q2 2016 (metric tons)	[redacted]						
Q2 2016 ($)	[redacted]						
Q3 2016 (metric tons)	[redacted]						
Q3 2016 ($)	[redacted]						
Q4 2016 (metric tons)	[redacted]						
Q4 2016 ($)	[redacted]						
Q1 2017 (metric tons)	[redacted]						
Q1 2017 ($)	[redacted]						
Q2 2017 (metric tons)	[redacted]						
Q2 2017 ($)	[redacted]						
Q3 2017 (metric tons)	[redacted]						
Q3 2017 ($)	[redacted]						
Q4 2017 (metric tons)	[redacted]						
Q4 2017 ($)	[redacted]						

Figure V-20. Trenton 5 Inventory Adjustments

Adjustments	Trenton 5 Blend
Q1 2016 (metric tons)	[redacted]
Q1 2016 ($)	
Q2 2016 (metric tons)	
Q2 2016 ($)	
Q3 2016 (metric tons)	
Q3 2016 ($)	
Q4 2016 (metric tons)	
Q4 2016 ($)	
Q1 2017 (metric tons)	
Q1 2017 ($)	
Q2 2017 (metric tons)	
Q2 2017 ($)	
Q3 2017 (metric tons)	
Q3 2017 ($)	
Q4 2017 (metric tons)	
Q4 2017 ($)	

Figure V-21. Trenton 6 Inventory Adjustments

Adjustments	Trenton 6 Blend
Q1 2016 (metric tons)	[redacted]
Q1 2016 ($)	
Q2 2016 (metric tons)	
Q2 2016 ($)	
Q3 2016 (metric tons)	
Q3 2016 ($)	
Q4 2016 (metric tons)	
Q4 2016 ($)	
Q1 2017 (metric tons)	
Q1 2017 ($)	
Q2 2017 (metric tons)	
Q2 2017 ($)	
Q3 2017 (metric tons)	
Q3 2017 ($)	
Q4 2017 (metric tons)	

Figure V-22. Port Hawkesbury Biomass Inventory Adjustments

Year	Blend
2016 (green metric tons)	[redacted]
2016 ($)	
2017 (green metric tons)	
2017 ($)	

We reviewed these adjustments for concerning trends or quantities in adjustments and found no such concerns in the adjustments. Lingan's adjustments represent a significant improvement from the previous Audit Period, which led the previous fuel auditor to recommend that NSPI conduct an investigation into the causes of the large adjustments in the prior period. (We address this issue in full in section 7 below.) Most of the plants saw bidirectional adjustments, suggesting no bias, and no plants had concerning levels of adjustments. Trenton 5's adjustments were all positive—as they were in the previous Audit Period—a point worth noting and watching going forward.

Figure V-23 shows that, fleetwide, total adjustments were bi-directional and resulted in a modest overall reduction adjustment for the two-year Audit Period, relative to the size of the overall fleet.

Figure V-23. Total Inventory Adjustments

Quarter	Metric Tonnes	Dollars
Q1 2016	[redacted]	
Q2 2016		
Q3 2016		
Q4 2016		
Q1 2017		
Q2 2017		
Q3 2017		
Q4 2017		
Total		

One additional inventory adjustment to highlight is shown in Table V-11 above, which shows all inventory adjustments for the Point Tupper Marine Terminal and Bear's Head storage location. On October 10, 2016, during an inclement weather event in which approximately 100 mm of rain fell,[19] approximately [redacted] MTs of mid-sulphur coal slid off of the stockpile at the Point Tupper Marine Terminal. Most of the coal that slid off the pile remained within the Point Tupper Marine Terminal site boundaries; approximately [redacted] MTs reached the shoreline and an unknown amount of coal slid into the Strait of Canso and was thus deemed unrecoverable. [redacted], which operates the Point Tupper Marine Terminal, did not provide an estimate of the lost coal, noting that the amount was unknown. NSPI estimated that between [redacted] and [redacted] MTs of mid-sulphur coal slid into the Strait of Canso and was unrecoverable; NSPI also estimates an inventory cost of [redacted]/MT of mid-sulphur coal at Point Tupper Marine Terminal in October 2016. The total estimated cost of coal that was lost is between [redacted]. NSPI's estimate appears reasonable to us: the quantities of lost coal it estimates are consistent with the inventory adjustment numbers in the fourth quarter of 2016 at Point Tupper Marine Terminal as well as the account of [redacted] in its correspondence with the Canadian environmental authorities, and the price estimate appears consistent with the per unit inventory costs at Point Tupper during October 2016.

19 Government of Canada, Daily Data Report for October 2016, Tracadie Nova Scotia, *available at* http://climate.weather.gc.ca/historical_data/search_historic_data_e.html.

In addition to the lost coal, costs were also incurred for environmental remediation. NSPI paid [redacted] and a second firm, [redacted] an additional [redacted] for cleanup services. The total of [redacted] was passed through to FAM customers. As part of the cleanup process, shoreline coal was recovered and returned to the pile. Consistent with its contract with NSPI and pursuant to the Point Tupper Marine Terminal environmental plan, [redacted] reported the incident to the Nova Scotia Department of Environment and coordinated on all necessary permitting to allow it to complete the cleanup process.

We reviewed weather data provided by the Government of Canada for as far back as was publicly available. The closest location to the Point Tupper Marine Terminal that collects precipitation data is at Tracadie, Nova Scotia, which is about 30 kilometers away. We determined that for that location, the precipitation that fell on October 10, 2016, was the single largest precipitation event day in the history of Tracadie, for which we had daily data from January 17, 2003, through June 1, 2018. Thus, we agree with the spirit of [redacted] assessment of the storm as "unprecedented," as it described the incident in a letter to the Nova Scotia Department of Environment. We also note that this incident is likely within bounds of the force majeure clause of NSPI's contract with [redacted]; the relevant clause states that force majeure excuses performance [redacted] Thus, it appears that NSPI properly addressed this event and appropriately passed through the costs of the lost coal and related environmental cleanup to FAM customers.

We further point out that NSPI has taken steps to prevent an event like this in the future. First, as noted earlier in this chapter, NSPI has built a retaining wall at the Point Tupper Marine Terminal. Second, [redacted] has adjusted its operating procedures at Point Tupper Marine Terminal to store mid-sulphur coal piles further away from the terminal's boundaries and to replace it with piles of low-sulphur coal. [redacted] concluded that mid-sulphur coal tends to be finer than low-sulphur coal due to differences in mining treatments, which makes it more susceptible to slides. Switching the locations of the piles can serve as a further operational protection against this kind of event in the future.

V.B.7. Liberty's 2014–2015 Recommendations

V.B.7.a. Biomass Fuel Manual Updates

The previous fuel auditor recommended that NSPI "[u]pdate the Fuel Manual with processes, procedures and controls for Biomass consistent to those of solid fuel."[20] The auditor explained that the updates "should cover procurement, inventory, and controls that address the need to verify accuracy in burns and receipts necessary for effective contract management and ensuring accuracy of costs."[21]

[20] 2014-2015 Liberty FAM Audit Report, page VI-25.
[21] 2014-2015 Liberty FAM Audit Report, page VI-25.

In its 2016 FAM Audit Action Plan, filed on January 31, 2017, NSPI stated that it agreed with the recommendation[22] and stated that it would update its biomass processes in Revision 10 of the Fuel Manual.[23] NSPI explained that

> [t]his item took time to complete as [NSPI] had to reassess its biomass requirements and correspondingly develop new biomass supply arrangements and management processes after the legislation changed. It required issuance of RFPs for onsite fuel handling and serves and for new standby fuel supply. Revision 10 of the Fuel Manual includes the revised biomass management processes in these agreements. This item is being managed by the Senior Manager, Solid Fuel who is modelling based on [NSPI's] coal and petcoke fuel management programs.[24]

NSPI has updated its biomass processes, which are now found in Revision 10 of the Fuel Manual. NSPI's Solid Fuel Portfolio Process, which is Link 6 to the Fuel Manual, now contains reasonable guidelines for biomass volume commitments; NSPI's Solid Fuel Inventory Management Process, which is Link 7 to the Fuel Manual, now contains a detailed and reasonable set of processes and targets for inventory of biomass fuel. The Solid Fuel Freight and Procurement Process, which is Link 8 to the Fuel Manual, now contains guidelines for solid biomass that subject biomass fuel and related services procurement to the same goal of seeking competitive outcomes (including through the use of competitive RFPs) as that of coal and petcoke, while also considering the unique transportation costs, quality evaluation, handling and storage characteristics of biomass fuel. The new Biomass Fuel Procurement Quality Assurance for Sampling and Analysis document, which is Link 10 to the Fuel Manual, contains detailed and reasonable processes for sampling, weighing, and assessing the quality of the biomass fuel delivered to PHP, while also containing processes for ensuring all provincial environmental requirements are met.

V.B.7.b. Lingan Inventory Adjustments

The previous fuel auditor also recommended that NSPI "[c]omplete an investigation of the Lingan inventory adjustments, and identify what steps need to be taken to reduce those adjustments."[25] The recommendation was made pursuant to a conclusion that NSPI's inventory adjustments during the Audit Period were "large" and "warranted attention."[26] The implication was that NSPI was burning less coal than it was recording—meaning that its inventories were actually larger than its processes indicated. This, in turn, required upward coal and petcoke adjustments and downward adjustments to fuel expense.

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22 2016 FAM Audit Action Plan, January 31, 2017, page 13.

23 FAM Audit Action Plan, January 31, 2017, page 9.

24 FAM Audit Action Plan, January 31, 2017, page 9.

25 2014-2015 Liberty FAM Audit Report, page VI-25.

26 2014-2015 Liberty FAM Audit Report, page VI-24.

In the FAM Audit Action Plan, NSPI stated that it agreed with this recommendation and noted that it had "begun an investigation," which would be complete by the third quarter of 2017.[27]

NSPI completed its "Lingan Inventory Report" in 2017. The report was conducted by FERM and focused on finding a root cause of the Lingan adjustments. NSPI identified two likely contributors to the Lingan inventory adjustments.

First, NSPI concluded that coal consumed at Lingan had, on average, over 4% more moisture content than the coal delivered to the International Pier. In other words, coal arriving by marine vessel into Nova Scotia for consumption at Lingan is picking up additional moisture between the time of its arrival and the time of its combustion at Lingan's boilers. This will bias Lingan's assumed coal burn upward, as moisture increases the weight of the coal and biases inventory measurements downward—thereby requiring more inventory adjustments, like those observed by the previous fuel auditor.

Second, NSPI concluded that its density assumption for Lingan's long-term "dead" storage pile was likely too high by about 13%. The higher the assumed density of a pile, the higher the assumed coal burn; thus, using a density value that is too high will lead to overestimations of burned coal volumes and underestimation of remaining coal inventory.

In addition to conducting this internal analysis, NSPI also surveyed 11 other utilities with coal-fired generation for potential best practices and improvements. Through this process, NSPI discovered that some of its processes are better than those of the survey participants. For example, only 2 of the 11 utilities conduct quarterly inventory surveys (the other 9 do it annually or semi-annually), and most utilities calibrated their gravimetric feeders less often than NSPI.

As a result of its investigation, NSPI laid out a series of actions it would take. Most notably, NSPI would (1) "continue regular spot checks of the plants' calibration process"; (2) "explore using potentially more accurate surveying technology, such as drones," after concluding that technologies such as GPS-enabled drones are industry standard; (3) adjust the density assumptions for each coal pile as determined through trials conducted during this investigation and conduct periodic checks of densities on different types of coal to verify and refine the densities being used with particular focus on the Lingan [Long-Term Dead Storage] pile"; (4) "[r]egularly monitor pickup of the Lingan coal piles, tracking this with the coal pile inventory reconciliation data"; and (5) use a newly installed certified truck scale to track deliveries to and from the long-term dead storage pile to increase accuracy.

The Lingan Inventory Report appears to us to be a thorough response to the previous fuel auditor's request. It appears to have identified the reasons for the bias in Lingan's previous inventory measurements and need for large adjustments and to have set forth reasonable corrective measures. As we note above, the results from the Audit Period demonstrate that Lingan's inventory adjustments during this Audit Period were much smaller and less frequent than the previous audit period. We would expect NSPI

[27] FAM Audit Action Plan, January 31, 2017, pages 13–14.

to continue to monitor the results of these new measures going forward, and would expect that NSPI consider applying any new best practices its employs at Lingan to its other solid fuel-fired generators.

V.B.8. [redacted] End of Life and the [redacted] Study of the Point Tupper Solid Fuel Circuit

As noted in Chapter IV on Solid Fuel Procurement, the [redacted] is nearing the end of its useful life and is projected to be exhausted of recoverable coal by the end of 2019. As we explain in that chapter, NSPI has taken a series of steps to address and plan for Trenton 6's operation and solid fuel supply without [redacted] supply. Here, we address NSPI's response to [redacted] impending end of life on its fuel supply management processes and assets.

Specifically, NSPI engaged [redacted] to study the fuel-handling system at the Point Tupper circuit—that is, at the Point Tupper Marine Terminal and the Trenton generating station. The study was to assess the impact of Trenton 6's larger reliance on imported coal as its domestic source of supply dwindles and eventually disappears. [redacted] submitted its report to NSPI on May 25, 2016; the report provided a series of suggestions to increase efficiency and capacity for handling and storing coal on the Point Tupper circuit. [redacted] also provided other recommendations related to fuel handling at Point Tupper Marine Terminal and at the Trenton station. [redacted] noted too that as a result of increased throughput and reliance on the Point Tupper circuit's solid fuel supply management, any issues that currently exist—such as limited storage capacity and common challenges like dealing with frozen coal—become magnified. The report contains a number of suggested solutions and investments, such as under-car heaters for the unloading area at Trenton for easier; safer unloading of coal from the railcars; side railcar shakers; safety measures for dozer operators at Trenton; a series of potential upgrades and maintenance of Trenton's coal handling system, including potential increases in feeder capacity; an additional railroad track at the Point Tupper Marine Terminal to increase loading capacity; and additional storage capacity at Point Tupper Marine Terminal. These suggestions each have costs; the additional rail track at Point Tupper Marine Terminal is estimated to cost [redacted] while the additional storage capacity at the Marine Terminal is estimated to cost [redacted].

V.C. Conclusions

Conclusion V-1: NSPI's use of Aligne as its transactional backbone in tracking solid fuel is appropriate. Aligne allows NSPI to reconcile the entire solid fuel supply chain and interacts directly with other NSPI programs, including NSPI's billing system (Oracle), thus reducing the likelihood of errors across the long chain of solid fuel management, from contract origination to billing of FAM customers.

Conclusion V-2: NSPI's processes and procedures for receipt of solid fuel are reasonable. NSPI competently manages a complex set of logistics to receive imported coal at two ports, move that supply to its plants by rail and truck, and receive domestic sources of solid fuel at multiple plants. FERM and the plant personnel have clearly delineated responsibilities in managing solid fuel supply that, during the

Audit Period, were carried out effectively. NSPI's ability to schedule vessel shipments to either of its two receipt terminals is a useful contractual flexibility.

Conclusion V-3: NSPI's processes for sampling, weighing, and testing coal and petcoke for quantity and quality specifications are reasonable, appropriately use a third party for assistance, and include a series of test points to ensure effectiveness.

Conclusion V-4: NSPI's processes for sampling, weighing, and testing biomass fuel are reasonable but are currently particularly reliant on [redacted] for effective testing. This is due to the fact that [redacted] is currently NSPI's contractor for sampling and testing the quality of the biomass fuel deliveries, while also being NSPI's [redacted] We see this as an inherent conflict of interest for this counterparty. [redacted].

Conclusion V-5: NSPI's contract administration processes are reasonable and include appropriate collaboration among FERM, senior NSPI management, terminal personnel, and plant personnel.

Conclusion V-6: NSPI enjoyed generally positive contract compliance from solid fuel suppliers during the Audit Period.

Conclusion V-7: Our samples of individual contracts for solid fuel shipments showed no concerns with NSPI's administration of its solid fuel contracts. In each case, NSPI relied upon third-party test results and made all appropriate and accurate calculations related to any deviations from the quantity and/or quality of the solid fuel from the contract specifications.

Conclusion V-8: NSPI's processes and procedures for solid fuel inventory targets are reasonable.

Conclusion V-9: NSPI suffered multiple late-year delays in solid fuel supply, which largely contributed to shortfalls from winter readiness target inventory levels entering the winter periods for both 2016 and 2017. The delays were not the fault of NSPI; moreover, NSPI rescheduled the shipments for later in the winter and responded to the delayed shipments appropriately by procuring some additional solid fuel at reasonable prices and terms.

Conclusion V-10: NSPI's target winter readiness solid fuel supply targets may become excessive as NSPI's coal- and petcoke-fired plants operate at lower capacity and less often at full load; thus, it would be reasonable to expect NSPI's target inventory levels—which are based on these plants running at full load around the clock—to also get lower eventually, particularly at the Sydney circuit, based on data observed during the Audit Period.

Conclusion V-11: NSPI's processes and procedures for adjusting solid fuel inventory are reasonable. During the Audit Period, we observed no concerning trends or large inventory adjustments.

Conclusion V-12: The coal slide event at the Point Tupper Marine Terminal resulted in the loss of approximately [redacted] in mid-sulphur coal and had cleanup costs of [redacted]. The event occurred during the heaviest day of precipitation in the Point Tupper area since 2003. NSPI and its contractor responded reasonably to the event and have since taken steps to minimize a repeat occurrence at Point Tupper.

Conclusion V-13: NSPI has appropriately addressed the previous fuel auditor's recommendation regarding the codification of biomass supply management processes by adding clear processes and procedures to the Fuel Manual.

Conclusion V-14: NSPI has appropriately addressed the previous fuel auditor's recommendation regarding the Lingan inventory adjustments. NSPI conducted a thorough internal study of the issue, memorialized in the Lingan Inventory Report, which included a survey of best practices from other utilities. NSPI identified the likely causes of the biased measurements and has taken steps to cure those biases, as well as to introduce other improvements in its processes. Lingan's Audit Period inventory adjustments did not appear biased, nor were they of the magnitude and frequency of the prior audit period.

Conclusion V-15: [redacted] end of useful life at the end of 2019 will impact NSPI's coal supply management on the Point Tupper circuit. Specifically, the loss of this domestic source of coal will mean Trenton 6 will have to rely on an increasing amount of imported solid fuel, eventually relying on imported fuel for 100% of its supply needs.

Conclusion V-16: NSPI took a number of reasonable steps to plan for [redacted] impending end of useful life, including commissioning a study on the ability of the Point Tupper circuit as it currently exists to handle additional imported coal to be burned at Trenton 6. It appears more is to be done, including the consideration of potential changes in fuel handling at Trenton and expansions at the Point Tupper Marine Terminal. (NSPI commissioned other studies that considered options and costs for expanding the Point Tupper Marine Terminal, noted in section 8 above.) Given this upcoming period of dynamic change at Trenton 6 and its concomitant impacts on the Point Tupper circuit, we provide a recommendation that NSPI report on its progress and planned capital expenditures to address fuel supply management on the Point Tupper circuit, including the Point Tupper Marine Terminal, the Trenton station, and the rail infrastructure connecting the two. (Recommendation).

V.D. Recommendations

Recommendation V-1: NSPI should provide regular updates to the Board and to stakeholders regarding its progress in planning for the operation of Trenton 6 on imported coal, including the impact on the Point Tupper Marine Terminal, the Point Tupper generating station, and the Trenton generating station. The updates should include planned capital expenditures to increase handling and/or storage capacity of the circuit, including that of the Point Tupper Marine Terminal, Trenton, and the rail infrastructure connecting the two. We suggest NSPI consider quarterly reporting to Board staff and stakeholders (through the FAM SWG meeting process) and biannual updates to the Board (through a filed status report).

VI. Natural Gas Supply Planning

VI.A. Background

NSPI has the ability to burn natural gas at its Tufts Cove facility as well as at the PHP biomass unit (as a secondary fuel) and engages in a series of planning and purchasing activities to keep those facilities supplied with natural gas. Our review of NSPI's natural gas activities during the Audit Period is covered in two chapters. In this chapter, we address the natural gas planning activities that NSPI conducted during the Audit Period. In Chapter VII, we address NSPI's procurement of natural gas.

VI.B. Findings

VI.B.1. Introductory Context for NSPI's Natural Gas Supply Options

NSPI aims to burn natural gas when it is available and the delivered price is expected to generate electricity at a cost lower than that resulting from burning HFO. Natural gas is purchased on a delivered basis, at the US-Canada border at Baileyville, New Brunswick, or at the landfall of the Sable Offshore Energy Project (SOEP) in Goldboro, Nova Scotia. Purchases at the latter two locations typically require NSPI to acquire pipeline transportation from Maritimes & Northeast Pipeline on a short-term basis. Natural gas requirements are estimated from PLEXOS model runs, and portions of those estimated requirements are hedged on futures and derivatives markets. As the derivative positions mature, the net cost (or benefit) is applied to the cost of fuel.[168]

As NSPI has pointed out in its Natural Gas Reports, the supply of gas available from the SOEP and Deep Panuke is rapidly declining.[169] Gas was not always available in the Maritimes, and there was insufficient pipeline capacity in New England and eastern Canada to move natural gas to NSPI on a consistent basis. Vaporized liquefied natural gas (LNG) was available from Repsol via the Canaport LNG facility in New Brunswick when prices were high enough to attract spot cargoes of LNG. As a

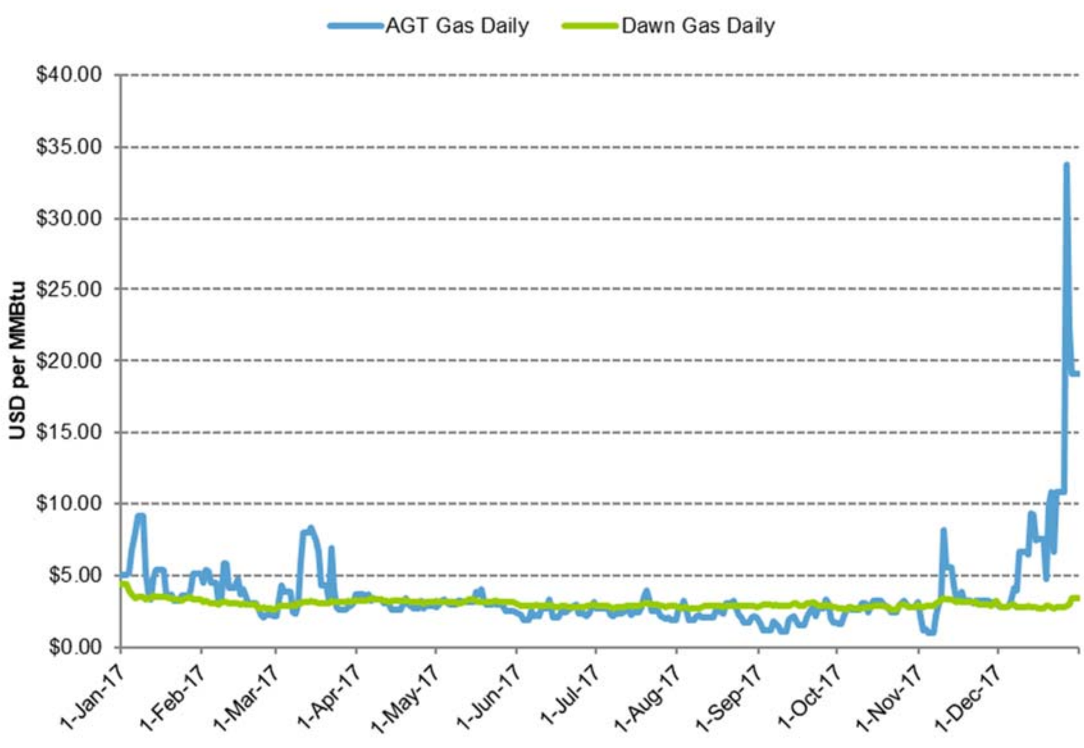
[168] If fixed price gas is purchased for a term that coincides with the term (partially or completely) of the derivative position and the derivative position is not unwound, then NSPI could be in an over-hedged position.

[169] ExxonMobil has indicated that it will not be renewing its transportation contracts on M&NE upon expiration in 2019. Shell's transportation contract has expired, and Shell now appears to be contracting on a month-to-month basis. Initial de-commissioning work on SOEP appears to have begun. See NGI's Daily Gas Price Index, "Sable's Days as NatGas Supplier to New England, Maritime Canada Appear Numbered," October 17, 2017, *available at* http://www naturalgasintel.com/articles/112114-sables-days-as-natgas-supplier-to-new-england-maritime-canada-appear-numbered and LINK System Informational Postings, "Maritime & Northeast Pipeline," *available at* https://infopost.spectraenergy.com/infopost/MNUSHome.asp?Pipe=MNUS as of March 28, 2018.

result of this evolving market situation, NSPI increasingly was a price taker in the local natural gas market.

The prices NSPI paid for natural gas reflected the alternative market prices available to the offshore Nova Scotia producers, all of which hold firm transportation contracts on the Maritimes and Northeast Pipeline (M&NE) (United States and Canada) to interconnections with Portland Natural Gas Transmission System (PNGTS) in Westbrook, Maine, and to the Algonquin Gas Transmission (AGT) and Tennessee Gas Pipeline (TGP) systems in northeastern Massachusetts. Gas trading locations and indices are associated with these pipeline interconnections, and prices at these locations reflect the constrained pipeline capacity feeding New England from producing regions. At times, these prices are the highest posted in North America. Figure VI-1 illustrates this effect by comparing the natural gas prices at AGT-CG (constrained) and Dawn (less/not constrained).

Figure VI-1. AGT Gas Daily vs. Dawn Gas Daily Prices (2016–2017)



Absent any new natural gas development in the Maritimes, reliable access to the lower natural gas prices in the Marcellus/Utica producing regions or Dawn could require that NSPI contract for firm pipeline capacity on pipelines that can access those lower prices. NSPI did investigate the alternatives and did participate in open seasons on both AGT and TGP projects, the latter of which did not go forward. PNGTS held an open season for its C2C project, which NSPI also considered.[170] NSPI considered and rejected bidding on short-term PNGTS capacity that occasionally became available.

While firm pipeline transportation contracts would allow NSPI to access lower-cost natural gas, they would require a significant commitment to fixed pipeline transportation costs. For example, an earlier estimate put this fixed cost at $2.80 (USD) per MMBtu per day[171] whether the transportation capacity was used or not. Depending upon the pipeline contract utilization rate, the effect on the average cost of natural gas could be significant.[172] This cost would be offset somewhat by lower commodity costs during periods of spot prices for delivered gas.

The projected capacity utilization rate also depends on the structure of the prices that is used to evaluate alternative natural gas arrangements. When initially ranking potential alternatives, it is common to compare the 100% load factor costs of delivered gas. This approach unitizes the fixed cost and adds it to the corresponding gas commodity cost. Using the above example, adding $2.80 per MMBtu per day to the corresponding gas commodity cost of $3.04 per MMBtu[173] at Dawn, Ontario, results in a 100% load factor price of $5.84 per MMBtu. If the fixed transportation cost is included as a variable fuel cost in a PLEXOS model run used to evaluate how much natural gas would be used, then the projected gas consumption would be lower than it would be if only marginal costs were used.

Using the marginal cost of natural gas ($3.04/MMBtu) in the dispatch simulation would likely result in more gas being burned and a higher capacity utilization rate for both the pipeline capacity and Tufts Cove. The fixed transportation costs would be added afterward to obtain a volume-weighted estimate of the all-in cost effect of a firm natural gas supply on the generated price of electricity.[174] Taken a step further, if a new, gas-fired, combined-cycle unit was modeled as a generation resource, the improvement in the unit heat rate[175] could offset a significant portion of the fixed natural gas transportation cost.

Figure VI-2 illustrates the effect on the cost of power of adding firm pipeline transportation to an existing fossil plant, and then adding a new, combined-cycle plant. This is only an illustrative example. In the Base Case, Gas Cost is the average of the daily AGT-Citygate gas prices for 2016–2017, plus [redacted] per MMBtu. The indicative result shows that simply adding firm transportation cost to transport

[170] NSPI stated that it asked TransCanada Pipelines to quote a fixed rate for a fixed term, but never received a proposal.

[171] Estimated cost of firm pipeline capacity from Dawn, Ontario, to Tufts Cove for 70,000 MMBtu per day [redacted]

[172] For example, a pipeline contract operated at a 50% percent utilization rate would double the effect of the transportation cost on the average delivered cost of the natural gas commodity [redacted]

[173] The average daily cost of gas at Dawn, Ontario, for 2017.

[174] It is Bates White's understanding that this is the approach used by NSPI in evaluating term pipeline capacity alternatives.

[175] For example, see the specifications for a GE 7HA combined-cycle power plant, with a heat rate under 5,500: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2017-prod-specs/7ha-power-plants.pdf.

gas to an existing plant would likely result in a higher cost of power. However, the better heat rate of a new, combined-cycle plant results in a lower cost of power even with the higher fixed transportation costs. Note that the cost of power drops even further (to [redacted]/MWh) if the Base Case scenario prices are used in a new, combined-cycle plant.[176] This example illustrates that the biggest benefit would derive from a change in generation technology, not in paying fixed costs to access a lower-cost gas supply; it suggests that some combination of firm and interruptible transportation might also be economic in a new, combined-cycle plant.

Figure VI-2. Illustration of the Effect on Power Cost Associated with Firm Pipeline Transportation and New Technology

Assumptions	Base Case	Add FT	Add FT & CCGT
[redacted]			

Results	Base Case	Add FT	Add FT & CCGT
[redacted]			

NSPI has examined some of these issues in various studies related to the Audit Period, and it is our understanding that studies are continuing. We requested studies and analyses performed by, or on behalf of, NSPI regarding the acquisition of pipeline transportation capacity. The various studies are summarized in the following sections, followed by our conclusions and recommendations. Some of these studies occurred prior to the Audit Period, but the results might have applied to the Audit Period. Overall, we found that NSPI evaluated a number of potential, firm pipeline transportation options and committed to one, but ultimately did not go through with it due to uncertain economics.

VI.B.2. NSPI's Longer-Term Studies of Natural Gas Supply Options

VI.B.2.a. The 2014 Integrated Resource Plan

NSPI's 2014 Integrated Resource Plan ("2014 IRP") was an evaluation of numerous generation mix scenarios under various input assumptions and sensitivities, each a Candidate Resource Plan. Existing coal plant lives of 50 and 60 years were maintained, while the model used was allowed to

176 Whether sufficient quantities of gas would be available on a delivered basis in the future at this price level would be a question, given the recent shutdown of Deep Panuke and planned shutdown of SOEP.

select for alternative generation, if economic on a net present value basis. Among the alternative generation options available was a combined-cycle plant with a heat rate of 7,200 Btu/kWh.[177]

The analysis relied on price forecasts, for all fuels, that increased over the IRP study period. The Base Case forecast for delivered natural gas prices increased at an annual compound rate of [redacted].[178] The price forecast included either fixed transportation charges or basis differentials to NSPI.[179]

The results of this analysis was an action plan that specified the steps NSPI would take to meet the objectives of the selected Candidate Resource Plan, which did not add any new generation, retired Lingan 2 with the advent of Maritime Link, and added additional DSM.[180]

As we detail in our Power Plant Performance chapter, we have a recommendation related to NSPI's future IRP planning; we suggest a more regular and robust process to be implemented. We include in that recommendation improvements directly related to the consideration of long-term gas supply options to ensure they are evaluated on a level playing field with other options.

VI.B.2.b. April 2017 Study of Gas Supply in the Constrained M&NE Region

In April 2017, NSPI completed a study that evaluated the amount of gas expected to be available, given the loss of gas supplies from offshore Nova Scotia, development of the natural gas reserves in New Brunswick beginning in 2027, and expansions of the PNGTS and AGT pipeline systems. In short, absent the pipeline expansions, there would be enough pipeline capacity to serve average summer demands on M&NE and PNGTS, but not peak period demands. During the winter, average demands would not be completely met, and peak demands would have to be met by vaporized LNG from Canaport. Adding an LNG export load into the mix would quickly result in average summer and winter loads that exceeded available pipeline capacity. Development of the natural gas reserves in New Brunswick would provide additional gas supply over time but would not exceed projected peak demand until the mid-2030s.

This study appears to compare all the projected demand for natural gas on the M&NE and PNGTS systems (not just the demand from firm shippers) to the projected pipeline capacity. It is not surprising that the demand exceeds the capacity, since pipeline capacity is built only for firm shippers. Any entity that was a firm shipper would not necessarily be affected by these events. This study suggests (not

177 2014 IRP Report Appendix B Page 20.

178 [redacted]

179 See 2014 IRP Report Appendix I Page 49, which shows the high prices and volatility characteristic of delivered natural gas prices that include either actual firm transport costs or the market value of transport costs as captured by basis differentials.

180 2014 IRP Report Chapter 5.

directly) that NSPI would likely have to gain a more certain access to natural gas supplies, or pay more for delivered gas, if it intends to keep burning gas.

VI.B.3. Audit Period Gas Contracting Options Open to NSPI

VI.B.3.a. PNGTS Open Season[181]

On September 29, 2016, NSPI received a notice of an open season from PNGTS offering various tranches of firm pipeline capacity from two receipt points with delivery to Dracut, MA. In short, year-round capacity was offered at [redacted] while summer-only capacity was [redacted] prices could be bid on all packages. Notably, the Pittsburg (TransCanada Pipelines (TCPL) interconnect) to Dracut packages were priced at the same level as the Westbrook (M&NE interconnect) to Dracut packages, possibly because the certificated capacity on PNGTS from Pittsburg to Westbrook (210,000 MMBtu/day) was greater than its certificated capacity on the shared facilities from Westbrook to Dracut (168,000 MMBtu/day).[182] This pricing structure suggests that there might have been an opportunity to acquire the Pittsburg to Dracut capacity for [redacted] transport the gas north on M&NE from Westbrook to Nova Scotia, and release the Westbrook to Dracut capacity, resulting in low to no cost transportation on PNGTS. Of course, there would be additional transportation costs on M&NE in both the United States and Canada.

NSPI decided to not bid on this capacity because a callable winter contract was already in place [redacted] NSPI also planned [redacted] for an additional contract for the following summer once SOEP came back on line. No further analysis was conducted at that time, as NSPI concluded that holding the PNGTS capacity would not be economic. Further, NSPI was unable to transact business in the United States because it lacked a corporate entity that held the necessary authorities.

NSPI's analysis was memorialized in a ROA memo to the FST one day *after* the bid submission window in the open season closed. In a subsequent analysis, NSPI provided a post hoc review of its decision to not bid on PNGTS capacity. The reasons (e.g., no available pipeline capacity upstream of PNGTS to Dawn, higher expected prices at Dawn, expiration of bids) led NSPI to conclude that bidding on the PNGTS capacity would not be cost-effective in the short term. This post hoc review provided good support for NSPI's decision and is a good example of the type of analysis that should

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181 Open seasons are the process by which interstate and interprovincial pipelines sell pipeline capacity.

182 In late 2017, FERC approved an increase in PNGTS' capacity so that disparity will be removed. The increased capacity will come from an increase in the pressure on TQM for deliveries into PNGTS, who has also filed with FERC for additional capacity expansions in the near future. http://www.naturalgasintel.com/articles/114291-pngts-files-for-second-phase-of-portland-xpress-project

be done, based on information available at the time the decision was made. We provide a conclusion and recommendation to this effect below.

VI.B.3.b. Hydro Quebec Release of PNGTS Capacity

On March 17, 2017, Hydro Quebec solicited bids for PNGTS capacity it held to serve a cogeneration plant in Bucksport, ME. NSPI declined to bid on this capacity because it had must-take contracts [redacted]. Further, as noted above, NSPI was not able to transact in the United States at that time. An analysis of the economics of transporting gas from Dawn to NSPI indicated that the maximum NSPI could bid was [redacted] to break even. It was not clear why NSPI would evaluate this opportunity since, as stated, its inability to operate in the United States would apparently render the question of whether to acquire PNGTS capacity moot. However, NSPI stated that, if an economic opportunity had arisen in the US, they would have taken the necessary steps to pursue it. We note NSPI has informed us of applications pending at the US Department of Energy, as well as before Canadian governmental authorities, to transact for natural gas in the US.

VI.B.4. The PNGTS PXP Project

As discussed below, PNGTS held an open season from August 30, 2017, through September 6, 2017, seeking interest in firm transportation on its system and related upstream systems ("PXP Project"). The precedent agreements underpinning this expansion were executed in November 2017. In a financial press release, PNGTS noted:

> PNGTS has executed Precedent Agreements with several Local Distribution Companies in New England and Atlantic Canada to re-contract certain system capacity set to expire in 2019 as well as expand the PNGTS system to bring its certificated capacity up to 0.3 Bcf/d. The approximately $80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased in over a three-year period beginning November 1, 2018.[183]

We requested that NSPI provide all analyses conducted during the Audit Period that evaluated alternate ways of purchasing natural gas, including any that considered contracting for firm pipeline capacity to locations outside of Nova Scotia. We requested discussion of storage options and open seasons for gas available during the Audit Period and all documentation and analysis related thereto.

183 TC Pipelines, LP, "TC Pipelines, LP Announces 2017 Third Quarter Financial Results," November 6, 2017, *available at* http://www.tcpipelineslp.com/news-releases-article.html?id=2168081.

NSPI's response did not include an evaluation of the PXP Project, which led to the conclusion that NSPI was either unaware of it or did not evaluate it.

We note that there were at least three reasons why NSPI did not consider the PXP Project: (1) NSPI was unaware of the PXP Project; (2) its aforementioned assertion that it could not do business in the United States; or (3) the preferred resource plan that emerged from the last IRP did not include an expansion of natural gas-fired generation, so long-term commitments to firm pipeline capacity were screened out.[184] We discuss our concerns with NSPI's modelling approach vis-à-vis natural gas in the next section.

VI.B.5. Evaluation of NSPI's Analyses of Gas Supply Options

In March 2014, NSPI considered participating in non-binding open seasons offered by Spectra (now part of Enbridge) and Kinder Morgan, the respective owners of AGT/M&NE and TGP. In addition to these projects, TCPL and PNGTS were proposing capacity expansions and fixed pricing. To aid in its evaluation, NSPI retained [redacted]. The recommendation to the FST was that NSPI submit non-binding nominations for [redacted] MMBtu per day to both pipelines.[185] NSPI went further with its analysis to conduct a detailed evaluation of pipeline expansions and other supply options and submitted a binding nomination to Spectra. This nomination was subsequently withdrawn when the favorable economics of transporting gas from the northeast United States appeared to deteriorate.

While this study was conducted outside of the Audit Period, it does serve to illustrate that NSPI considered whether to obtain firm pipeline transportation capacity that was projected to be available in starting around 2016.[186] The study was detailed and considered quantitative and qualitative information, along with uncertainties. While Bates White had some initial concerns that NSPI was considering only [redacted] percent load factor gas costs in their analyses, NSPI clarified that PLEXOS runs used only marginal gas costs, and that any fixed, gas-related costs were added after the model runs.

We note that, going forward, NSPI should continue their approach to assessing natural gas supply opportunities by (1) using the variable cost of natural gas (commodity, fuel, and variable pipeline charges) from various supply areas as the inputs into PLEXOS model runs and (2) adding the corresponding fixed pipeline transportation runs to the cost of generation subsequent to the model runs. We include a recommendation below on this issue.

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184 The IRP process included a combined cycle unit with a heat rate of 7,800 Btu/kWh, but did appear, at first, to model firm gas pricing structures with higher fixed transportation costs and lower variable commodity costs, escalated separately.

185 At the time, the projects were considered by many to be mutually exclusive.

186 The Spectra project was delayed and was still under construction as of Spring 2018.

We also note that there appears to be at least one opportunity open to NSPI for pipeline transportation capacity to access natural gas supply outside the Maritimes.[187] In April 2018, PNGTS filed phase I of its PXP, which will add 39,841 thousand cubic feet (Mcf) per day of capacity on its Pittsburg to Westbrook segment and 1,641 Mcf per day on the Westbrook to Dracut segment.[188] The following month, PNGTS filed Phase II of PXP (11,321 Mcf per day), which is expected to be superseded by Phase III, which would provide an incremental 24,375 Mcf per day of capacity.[189] Importantly, PXP includes capacity on the TCPL and Union Gas systems, which ensures that the necessary pipeline capacity will be built on three systems to transport gas. These projects will increase the availability of gas in the northeast United States and Maritimes Canada, but only to the extent the capacity is not used by firm shippers. At the June 2018 Local Distribution Companies Forum meeting held in Boston, PNGTS provided an update of the PXP expansion that would increase total system capacity to 300,000 Mcf/day.[190] The PXP expansion is purportedly still open to new shippers and thus is a current option open to NSPI.

VI.B.6. Liberty's 2014–2015 Recommendations

The previous fuel auditor had two recommendations related to gas supply planning. First, Liberty recommended that NSPI "[d]evelop a strategy for assuring access to gas sources outside the Martimes."[191] NSPI agreed with this recommendation, noting that this item will be addressed as part of the Board-mandated "Generation Utilization and Optimization study [process] being carried out by Synapse."[192] NSPI's response to this recommendation appears reasonable; moreover, we note that our recommendation in the Power Plant Performance chapter regarding IRP planning will ensure that NSPI regularly and robustly considers its options to contract for gas outside the Maritimes.

Liberty's second recommendation was that NSPI "[e]ngage the NSUARB and [NSPI's] stakeholders to discuss how to keep them informed about [NSPI's] efforts to improve access to natural gas."[193] NSPI agreed with this recommendation as well, noting that it had engaged with the FAM Small Working Group (SWG) on multiple occasions, including inviting formal comments in 2017.[194] NSPI's response to this recommendation appears reasonable, and we note that stakeholders in the

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187 We expect that NSPI's decision process and outcome will be a topic of review in the next FAM Audit.

188 Natural Gas Intel, "PNGTS Files for Second Phase of Portland Xpress Project," May 7, 2018, *available at* http://www.naturalgasintel.com/articles/114291-pngts-files-for-second-phase-of-portland-xpress-project.

189 Natural Gas Intel, "PNGTS Files for Second Phase of Portland Xpress Project," May 7, 2018, *available at* http://www.naturalgasintel.com/articles/114291-pngts-files-for-second-phase-of-portland-xpress-project.

190 Natural Gas Intel, "PNGTS Files with FERC for Capacity Expansions," April 23, 2018, *available at* http://www naturalgasintel.com/articles/114122-pngts-files-with-ferc-for-capacity-expansions.

191 Liberty 2014-2015 Audit Report, page III-9.

192 NSPI 2016 FAM Audit Action Plan, July 31, 2017, pages 12–13.

193 Liberty 2014-2015 Audit Report, page III-10.

194 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 13.

SWG process have the opportunity to suggest or raise items to NSPI to be covered in future SWG meetings or other contexts.

VI.C. Conclusions

Conclusion VI-1: NSPI has evaluated alternative natural gas options from time to time, but as evidenced by its analyses conducted during the Audit Period, has not been satisfied that the additional fixed cost associated with the firm transportation would be offset by lower commodity costs of gas. Absent new technologies, the example in Table VI-1 supports this perspective. However, NSPI's analyses also conclude that the availability of gas in Nova Scotia will continue to decline, which would likely raise prices or result in using more oil and coal.

Conclusion VI-2: The completion of Atlantic Bridge and future PNGTS expansions will provide some offset to the loss of SOEP and Deep Panuke during the summer periods.

Conclusion VI-3: To the extent gas is a desired portion of NSPI's fuel mix, then steps will likely need to be taken to access the necessary gas supplies. The loss of access to gas supplies could also diminish the value of the gas/oil option at Tufts Cove.

Conclusion VI-4: In assessing gas supply options, a more detailed understanding of the impact of the cost of firm pipeline transportation and lower cost gas commodity could be gained by analyses that used only the variable cost of gas in PLEXOS dispatch runs, estimated the resulting gas demand,[195] and then added any fixed transportation costs to the generation cost after the model runs were complete. We do not include a recommendation to this point, but note this conclusion for NSPI's consideration in future analyses of gas supply options.

Conclusion VI-5: While NSPI has included new, hypothetical, combined-cycle gas generation facilities in past analyses, it should continue to update assumptions regarding specifications of newer technology and whether the cost of firm transportation capacity and access to lower-cost gas commodities would be offset by the higher efficiency of newer combined-cycle units.

Conclusion VI-6: NSPI demonstrated that it analyzed potential pipeline transportation options, and it should continue to do so. Given the rapid changes in the Maritimes natural gas markets, these opportunities should be carefully monitored and decisions documented. To the extent it is not already being done, conducting ROAs on declined significant opportunities, similar to the post hoc analysis regarding PNGTS opportunities, could prove valuable.

[195] NSPI states that its analyses did use only the variable cost of gas in its PLEXOS runs, but it was not clear how the gas was transported to Nova Scotia, and the cost, if any, of that transport.

Conclusion VI-7: NSPI appropriately responded to the previous fuel auditor's recommendations related to natural gas supply planning.

VI.D. Recommendations

Recommendation VI-1: We recommend that NSPI's analysis of significant, longer-term, natural gas opportunities (e.g., transportation, supply, and storage greater than or equal to 5,000 MMBtu per day, and for a term greater than or equal to one year) be formalized in ROAs submitted to FST prior to the deadline for deciding whether to transact, even if NSPI's analysis suggests rejecting or passing on the opportunity.

Recommendation VI-2: When NSPI assesses natural gas supply options that rely on firm pipeline transportation, it should (1) continue to use the variable cost of natural gas (commodity, fuel, and variable pipeline charges) from various supply locations as the inputs into PLEXOS model runs and (2) add the corresponding fixed pipeline transportation costs to the cost of generation subsequent to the model runs.

VII. Natural Gas Procurement

VII.A. Background

In this chapter, we assess NSPI's processes and results of its natural gas procurement activities during the Audit Period.

The natural gas market in Nova Scotia is supply constrained, which limits the number of natural gas suppliers and the availability of natural gas.[196] As a result, NSPI was often a price taker during the Audit Period, and at times purchased all the natural gas made available by its suppliers. When HFO cost less than natural gas, NSPI had the ability to switch to HFO and avoid high, peak-period, natural gas prices.

As production from SOEP and Deep Panuke continues to decline, at some point all natural gas will have to be imported from outside Nova Scotia—primarily from the United States or western Canada.[197] This changing situation may require that NSPI contract for pipeline capacity back to production areas (e.g., Pennsylvania) or supply hubs (e.g., Dawn, Ontario). NSPI notes that it is aware of this possibility and that it continues to monitor the situation.

NSPI maintains a number of procurement contracts with various counterparties that supply and trade in natural gas. These contracts allow NSPI to purchase natural gas, when available at desirable prices, and to sell excess gas to manage natural gas commitments. NSPI also maintains agreements with financial counterparties to facilitate transactions in natural gas-related derivatives.

The focus of this section is on gas procurement decisions and contract management, along with analyzing transaction samples from initiation to reporting. Following a more general discussion, we focus on areas, some of which had the potential to be serious. Other than our discussion of some concerns regarding transactions in December 2017, we have not, at this point, identified improprieties that had a material effect on the FAM customers. These will be covered in turn. Specifically, we address transactions with Emera, Allegro data entry, daily trading notes and spreadsheets, allocating the cost of fuel gas and gas transactions during a month of natural gas price volatility (December 2017).

[196] See section B.1 of the Natural Gas Supply Planning chapter.

[197] Shell has reportedly started the de-commissioning process at its Sable Island facility and Encana has filed to abandon Deep Panuke. See, e.g., "Nova Scotia's Deep Panuke Natural Gas Projects Drying Up," *Chronicle Herald*, May 29, 2017, *available at* http://thechronicleherald.ca/business/1473337-nova-scotias-deep-panuke-natural-gas-projects-drying-up.

VII.B. Findings

VII.B.1. NSPI's Natural Gas Procurement Processes

Natural gas is purchased pursuant to standard-form, natural gas contracts, modified to address specific requirements of NSPI and their respective counterparties. This standard-form contract was developed by the North American Energy Standards Board (NAESB) and is widely used in buying and selling natural gas. Agreed-on quantities, prices, receipt and delivery points, and other performance characteristics are contained in one or more confirmations, which can extend beyond the term of the underlying NAESB agreement.

NSPI bought natural gas delivered to the Canadian border at Baileyville, ME, or at Goldboro, or Tufts Cove in Nova Scotia. The majority of the natural gas purchased was delivered to Tufts Cove. NSPI did not maintain any pipeline transportation contracts or purchase natural gas outside of Canada. The prices NSPI paid generally reflected the price of the natural gas commodity in New England markets, plus the *value* of the pipeline capacity needed to deliver gas to Nova Scotia. During periods of slack demand, the price of gas and the value of the pipeline capacity were low, but both prices moved higher during periods of strong demand. Generally, and subject to caveats explained in this chapter and in other chapters, when natural gas was more costly than HFO, or costs could be lowered by burning HFO and selling natural gas, NSPI switched to using HFO at Tufts Cove.

During the Audit Period, NSPI had active NAESB agreements in place with the nine counterparties listed in Figure VII-1.[198]

Figure VII-1. NSPI's Natural Gas Counterparties

Counterparty
[redacted]

[198] NSPI had NAESB agreements in place with other counterparties, but no transactions were executed under those contracts during the audit period.

These NAESB contracts allow NSPI to both buy desired quantities and sell unneeded quantities of natural gas to its counterparties. NSPI has stated that it does not engage in trading natural gas;[199] in other words, NSPI only purchases natural gas when it needs it for consumption at its gas-fired generating facilities and only sells natural gas when it is not needed and it is economic to do so. NSPI's Fuel Manual contemplates the use of competitive RFPs in procuring natural gas,[200] though other approaches are also used, such as direct negotiations.[201] NSPI set out two RFPs during the Audit Period; in both cases, the winning bidders were the lowest cost offers.

Using the trade-level data provided by NSPI, Figure VII-2 below shows the quantity of gas and associated dollar amounts (USD) for 2016 and 2017. [redacted] We address December 2017 results later in this chapter.

Figure VII-2. Summary of Annual Natural Gas Costs[202]

	2016		2017	
	MMBtu	Amount (USD)	MMBtu	Amount (USD)
Purchased	[redacted]			
Sold				
Net Purchased				
US$ per MMBtu				

VII.B.2. Transaction Review: Emera Transactions

To address concerns about the potential for preferential trades with Emera, we examined NSPI's natural gas transactions with Emera in further detail. During 2016, transactions were conducted with two Emera entities; during 2017, transactions were conducted only with Emera Energy LP. As we show in this section, NSPI's commercial transactions with Emera were within the bounds of normal market variation. While some instances of higher prices did occur, these appeared to be the result of market and operating conditions, not the result of NSPI providing Emera with preferential treatment.

We reviewed all transactions where NSPI purchased natural gas from Emera and at least one other counterparty.[203] There were 38 days in 2016 when this occurred, with 31 Next Day, 4 Intra Day, and 3

199 In this context, trading refers to buying natural gas for the purpose of re-selling it to other purchasers, and not for consumption. However, we will use the words "trade" and "trading" to describe purchase and sales transactions by NSPI with various counterparties.

200 Fuel Manual Revision 10, sections 9.2 and 9.3.

201 Fuel Manual Revision 10, section 9.2.

202 Note that this table includes natural gas commodity costs and does not contain all natural gas transportation costs. We report this table in USD because NSPI's natural gas purchases and sales are conducted USD.

203 To focus on price levels, the transactions reviewed were comparable by trade date, flow date, term, and trade type.

Late Day transactions. For Next Day transactions, Emera was priced higher than the average price (without Emera included) on 18 days and priced lower than average on 13 days. When compared to the highest price paid by NSPI on each day, Emera was priced higher on 13 days and lower on 18 days.

The largest price discrepancies were in the first five transactions that occurred in 2016 between January 28 and March 7, particularly the February 2 trading day. [redacted] On two days, the Emera price equaled the highest price charged by others.

[redacted] The remaining 32 transactions were within an acceptable range. The details are presented in Appendix VII-A.

In 2017, NSPI purchased gas from Emera on 83 days, with 74 Next Day, 6 Intraday, and 3 Late Day transactions. Emera was priced higher than average on 50, 1, and 2 days for Next Day, Intra Day, and Late Day transactions, respectively. When compared to the highest prices paid, Emera was higher on 33, 1, and 2 days for the same respective transaction categories. There were seven days where transactions with Emera were at noticeably higher prices, but a review of the daily records indicated that the higher prices were due to [redacted]. Figure VII-3 below shows all trades with Emera in which the price paid was higher than both the average price and the highest price paid for gas by NSPI on that day.

Figure VII-3. Purchases from Emera at a Price Higher than Average and Higher than the Highest Price Paid

	2016			2017		
Price	Next Day	Intra Day	Late Day	Next Day	Intra Day	Late Day
Higher than Average	18	1	3	50	1	2
Lower or equal to Average	13	3	0	24	5	1
Higher than Highest	13	0	1	33	1	2
Lower or equal to Highest	18	4	2	41	5	1

Figure VII-4 summarizes the costs associated with those transactions that were higher than average price and higher than highest price. The MMBtu are those associated with the selected Emera transactions, which do not include buy transactions on days when there was no other counterparty.

Figure VII-4. Cumulative Differences Paid to Emera NSPI for Select Transactions

Difference from Average	2016	2017	Total
Next Day	[redacted]		
Intra Day			
Late Day			
Total			
Total MMBtu			
USD per MMBtu			
Difference from Highest	**2016**	**2017**	**Total**
Next Day	[redacted]		
Intra Day			
Late Day			
Total			
Total MMBtu			
USD per MMBtu			

While Emera was a counterparty to NSPI during the Audit Period, it did not necessarily transact with Emera each month. A review of the individual Emera transactions, coupled with a review of the gas marketers' daily notes, did not indicate a pattern of preferential transactions with Emera that put the FAM customers at a disadvantage.

Emera also purchased gas from NSPI. [redacted] These gas sales transactions (used to better match gas burns with gas purchases) are typical in the natural gas industry and reflect one of the tools used to balance pipeline takes.[204] [redacted] Figure VII-5 summarizes the NSPI transactions with Emera.

204 M&NE allows some balancing flexibility in its tariff, but does require that shippers maintain a specified tolerance between the quantity of gas put into the pipeline and the quantity withdrawn.

Figure VII-5. Summary of NSPI Transactions with Emera 2016–2017

	2016		2017		Total	
	MMBtu	Amount (USD)	MMBtu	Amount (USD)	MMBtu	Amount (USD)
Purchased	[redacted]					
Sold						
Net Purchased						
USD per MMBtu						

When compared to other suppliers over the Audit Period, NSPI purchased natural gas from Emera at an average price that was slightly above the weighted average cost of its other gas purchases [redacted]). Figure VII-6 compares the price that NSPI paid to Emera for natural gas to the prices paid to other suppliers. While the use of average prices can hide some daily volatility, Emera transactions generally tracked market conditions.

Figure VII-6. Comparison of Natural Gas Prices Paid by NSPI 2016–2017[205]

[redacted]

[205] This figure lists a single Emera entity – Emera Energy Inc. – which includes all Emera-related transactions during the Audit Period.

VII.B.3. Transaction Review: Other Counterparties

We reviewed NSPI's transaction-level natural gas data with other counterparties during the Audit Period. In particular, our review focused on looking for overall price levels and transactions that appeared out of the ordinary. We focused on the order in which transactions occurred, relying on the trade information input by NSPI personnel and trade numbers assigned by Allegro to examine trade-level information. We also examined other processes NSPI used in tracking and managing natural gas transactions. The results of these analyses follow.

VII.B.3.a. Allegro Data Entry

We analyzed the trade-level data used in NSPI's normal course of business. In conducting the analyses, we noticed that the dates on a number of trades were associated with trade numbers higher than contemporaneous trades. Since Allegro automatically assigned sequential trade numbers, this trade number discrepancy indicated that the trade was entered into Allegro at a date later than the trade occurred. Over the period from January 26, 2016, to September 6, 2016, 33 trades were identified as being entered late into Allegro, ranging from 1 to 45 days after the trade date. The majority of the late-entered trades occurred in January and February of 2016; Figure VII-7 summarizes the results.

Figure VII-7. Summary of Late-Dated Trades[206]

Month	No. of Trades	MMBtu	USD Value (excl. sales tax)
January 2016	[redacted]		
February 2016			
March 2016			
April 2016			
July 2016			
September 2016			

At the end of each month, the Allegro data were combined with other data in an Excel workbook to generate inputs for the financial group at NSPI. This workbook was also used to calculate the average cost of gas, by day, for that month. These average daily costs were then multiplied by the gas burned at Tufts Cove and PHP to determine the daily cost of natural gas for each facility.

A review of the January 2016 version of this workbook indicated that late-dated January trades [redacted]), entered after February 4, 2016, did not appear to be included in the January monthly

[206] This table is in USD due to the fact that the transactions settled in USD.

average cost of gas calculation. The trades did not appear in the Allegro data used in February and March calculations either. This suggested that any invoice received from venders of this gas would not have matched what was transmitted to the financial group. However, given the time lag from the end of a month until an invoice was received (approximately 22 days) and payment due (another few days), there apparently was time for NSPI to review the invoice, correct its records, and pay the invoice on a timely basis. Material provided by NSPI showed the late-dated trades on the appropriate invoice verification documents.

We understand that NSPI discovered these late trade entry problems and that corrective action was taken. Further, NSPI has instituted a review and approval process to ensure this entry error will not reoccur. This activity does not appear to have had a negative effect on the FAM customers, and we observed no further instances of late-dated entries in the remainder of the Audit Period.

VII.B.3.b. Electronic Spreadsheet Notes

NSPI maintained electronic spreadsheets that captured daily trading information to support natural gas purchase and sale decisions. The data captured generally included supply availability, quoted prices, selected transactions, related market information, and the trade numbers assigned by Allegro. The results were used to estimate a weighted-average cost of gas for the next Gas Day or Gas Days. The price of HFO was also tracked, along with information about the status of generators. Notes on information communicated to power traders was also tracked.

In 2016, the revised spreadsheets closely mirrored the information entered into Allegro, but the data were not always the same. When compared to Allegro transactions, the spreadsheets contained a handful of small discrepancies such as different trade class, price, and trade date. A few trades were captured by Allegro but were not listed in the spreadsheets. NSPI explained that these spreadsheets were daily worksheets that were copied and written over the next day. As a result, the spreadsheets could contain artifacts and reflect what-if calculations that may or may not have happened. However, we did notice that the spreadsheets were subsequently revised to reflect the late-assigned Allegro trade numbers, which suggests a higher level of formality exists for these spreadsheets.

These spreadsheets, while somewhat informal in early 2016, served to capture valuable information that supported natural gas transactions and purchasing decisions. Useful information and details were memorialized, and the data appeared to support the gas transactions. As the spreadsheets evolved over the two-year Audit Period, the information tracked and the detail captured increased, providing a more useful context for tracking natural gas purchasing and management decisions. This daily documentation process, by month, is useful and should be continued.

VII.B.3.c. Tracking Fuel Gas

NSPI buys natural gas from [redacted] and other suppliers at Goldboro, and it is delivered to Tufts Cove. Using purchases from [redacted] as an example, gas purchased at Goldboro requires NSPI to use [redacted] pipeline capacity, which requires additional gas purchases to meet the M&NE fuel requirements. Gas purchased on a delivered basis to Tufts Cove or PHP does not have the same restrictions. On days when NSPI purchased both types of gas from [redacted] the fuel gas purchase was associated with the gas purchased at Goldboro. Accordingly, even if the contract price were the same, the gas purchased at Goldboro would effectively be more expensive because of the additional fuel gas. The [redacted] fuel gas purchases were then allocated over all the [redacted] purchases. To the extent the Goldboro gas was resold, the true cost of that gas might not be captured by the resale price, or costs might be incorrectly allocated to NSPI or PHP.

Currently, this practice has little to no effect on FAM customers, as most of the [redacted] gas is purchased to generate power for FAM customers. However, NSPI anticipates taking a larger position in managing natural gas transportation and gas purchases both within and outside of the Maritimes (including gas exchanges, resales, etc.). As this strategy is implemented, tracking the actual costs associated with managing discrete gas transactions would be preferred to ensure that FAM customers do not implicitly subsidize other transactions.

VII.B.3.d. December 2017 Results

In this section, we provide our analysis of one sampled month of natural gas transactions—December 2017—which was a month of high gas price volatility. This discussion is a useful context for our complete analysis of December 2017 results in the Hedging chapter. Here, we focus on the natural gas transactions themselves, rather than on NSPI's approach to hedging.

On August 9, 2017, NSPI issued an RFP for gas supplies with a term of up to one year, although longer terms would be considered. [redacted] responses were received from [redacted] bidders. As of August 21, 2017, the forward strips showed that the prices for December gas at AGT-CG and TGP Z6 were $6.36 per MMBtu and $6.39 per MMBtu, respectively. The responses offered a mix of daily and monthly pricing, with one bidder offering a financial swap for up to [redacted] MMBtu per day. [redacted]

The price at AGT-CG reflects the NYMEX Henry Hub price, plus the basis, or price differential, between Henry Hub and AGT-CG. Natural gas prices at AGT-CG were volatile and began creeping up after December 10, before rising sharply in the latter half of December. While we discuss all NSPI's hedging activities related to these price spikes in the Hedging chapter, it is important to note here that as natural gas prices spiked, NSPI sold some gas in mid-December and then stopped buying incremental gas on December 23. NSPI began selling the must-take [redacted] and [redacted] gas back into the market. The dollar amounts netted from settling the forward monthly contracts in November 2017 were added to the daily gas costs. An estimate of the effect of these transactions is shown in Figure VII-8.

Figure VII-8. Summary of December 2017 Natural Gas Transactions[207]

	MMBtu	Amount
Gas Purchased	[redacted]	
Less: Gas Sold		
Net Gas Purchased		
Est. Hedge Effects (Gain)/Loss		
NYMEX Hedge	[redacted]	
AGT Basis Hedge		
Net Hedge Effect		
Effective Gas Costs		
Effective Gas Cost	[redacted]	
Cost per MMBtu		

NSPI mitigated the effects of the spiking gas prices by selling must-take gas, at a loss, into the market. All in all, NSPI appears to have sold [redacted] MMBtu of gas for a loss of [redacted], or [redacted] of the net gas purchases for the month. This helps underscore a point we make in the Hedging chapter regarding the fact that NSPI's ability to sell must-take natural gas back into the market helps hedge NSPI's exposure to daily gas price changes, but only partially.

VII.C. Conclusions

Conclusion VII-1: NSPI's approach to natural gas procurement has many industry standard features, including the use of standardized contracts with counterparties, competitive RFPs, and a combination of short-, medium-, and long-term natural gas supply contracts.

Conclusion VII-2: NSPI's commercial transactions with Emera appear to be within the bounds of normal market variation. While some instances of higher prices did occur, these appeared to be the result of market and operating conditions, not the result of NSPI providing Emera with preferential treatment. Nevertheless, given the affiliate nature of these transactions, we provide a recommendation that gas traders explicitly capture the reason(s) for transacting with Emera when at higher prices than other available offers. (Recommendation)

Conclusion VII-3: The problem with the late entry of trades into Allegro was raised with NSPI, which responded by stating it was aware of the issue and had taken corrective action. Evidence during the remainder of the Audit Period suggests NSPI's corrective action has been effective; nevertheless, we

[207] This figure excludes pipeline transportation costs.

provide a recommendation suggesting a simple enhancement that may assist in preventing this issue from reoccurring. (Recommendation)

Conclusion VII-4: The maintenance and quality of the gas traders' daily trading notes and spreadsheets improved over the Audit Period and provide a valuable database to support decision making. In the spirit of continuous improvement and underscoring the usefulness of these documents, we provide a recommendation below. (Recommendation)

Conclusion VII-5: Allocation of fuel gas is noted, but not considered a current issue. We provide a forward-looking recommendation addressing fuel gas. (Recommendation)

Conclusion VII-6: NSPI's gas purchases in December 2017 demonstrate NSPI's approach to purchasing gas at daily prices. NSPI does have the ability to resell must-take natural gas, but as December 2017's experience shows, that may be done at a loss in times of rising prices.

VII.D. Recommendations

Recommendation VII-1: To the extent NSPI transacts with Emera from time to time, we recommend that the reasons be explicitly captured in the traders' daily spreadsheets.

Recommendation VII-2: We recommend that NSPI consider instituting a simple screening to ensure trades are being entered into Allegro on a timely basis. For example, graphing Allegro trade numbers against days should be close to linear. Any outliers could be evidence of trades not entered on a timely basis.

Recommendation VII-3: We recommend that NSPI continue the practice of maintaining daily gas trading records and look for ways of enhancing the quality and consistency of the information captured, including daily operational descriptions and the reasons that gas burns might have deviated from the expected.

Recommendation VII-4: We recommend that NSPI not allocate fuel gas costs over all gas purchased from a single seller, but keep the fuel cost associated with the purchase that required the purchase of fuel.

VIII. Oil Procurement and Management

VIII.A. Background

While fuel oil is a relatively small portion of NSPI's overall fuel purchases, NSPI's generation facilities do use in the generation of electricity. This chapter addresses NSPI's procurement and management of fuel oils.

VIII.B. Findings

NSPI uses three types of fuel oils in generating power: HFO, furnace oil, and diesel. We refer to furnace oil and diesel as light fuel oils, or LFO. For the Audit Period, NSPI spent about [redacted] on fuel oils, or about [redacted] of total FAM expenditures. We split our findings into two sections, beginning with HFO and then turning to LFOs.

VIII.B.1. Heavy Fuel Oil

NSPI uses HFO for two purposes. First, it can be used for generation at the Tufts Cove steam units (1, 2, and 3) in lieu of natural gas, or at many of NSPI's solid fuel-fired generators as a backup source of fuel. Second, it is used at most of NSPI's solid fuel-fired generators for start-up, flame stabilization, and extra heat at times of high capacity utilization. For the entire Audit Period, NSPI spent about [redacted] on HFO, representing approximately [redacted] of total FAM expenditures.

VIII.B.1.a. HFO Procurement

NSPI purchased HFO pursuant to RFPs when the near-term forecast indicated that there would be sufficient room in the storage tanks. HFO was delivered directly to Tufts Cove via ocean-going vessels and then redelivered to other plants via truck. During the Audit Period, NSPI had a single HFO trucking supplier, [redacted], under a contract executed in 2015. The contract with [redacted] does not contain a guaranteed minimum number of deliveries either overall or to individual locations, which is a good contractual protection for NSPI and customers. Trucking shipments under the contract are "as and when needed" and allow NSPI to contract with an alternate carrier if [redacted] does not perform its duties. Under the contract, deliveries to Lingan are the most expensive, followed by Point Tupper, and then by Trenton; cost is a function of the distance of the plants from Tufts Cove.

During the Audit Period, NSPI bought HFO twice, and in both cases using RFPs. The responses were reviewed by NSPI personnel, and FERM made recommendations to NSPI senior management. Records were kept of the offers and purchasing decisions. The winning supplier was selected based on the lowest price and a reliability assessment regarding the source of the HFO. Quoted prices were typically tied to the Platts average New York Harbor cargo assessment (USD per barrel) for #6, 1.0% sulphur residual oil,[1] plus an adder, which decreased with the number of barrels ordered. As with all HFO purchases, the oil was priced to be delivered ex-ship to Tufts Cove. Independent admiralty services were employed to verify that HFO deliveries met specified quantities and specification.

To provide additional detail, during January 2016, NSPI issued a single cargo RFP to 14 companies for HFO to be delivered in February or March of 2016. Responses were received from [redacted] suppliers, with an indication from [redacted]. NSPI selected [redacted] as the lowest cost offer. This contract allowed NSPI to order either [redacted] at a time, with a [redacted] notice. The respective adders were [redacted] per barrel.

NSPI issued another single-cargo HFO RFP in December 2016 for January or February 2017 delivery. Offers were received from [redacted] suppliers, with [redacted] being the lowest bidder. Its offer was [redacted] with an adder of [redacted] [redacted] also offered [redacted] with an adder of [redacted] per barrel. Both offers were for HFO delivered to Tufts Cove, ex-ship.

VIII.B.1.b. HFO Consumption

HFO was used primarily at Tufts Cove, where it could be burned instead of natural gas and serve as a partial hedge against natural gas price spikes. HFO was also co-fired in some of the coal units or burned when starting the coal units. Based on plant-level data during the Audit Period, NSPI used [redacted] barrels of HFO (approximately [redacted] MMBtu) at a cost of [redacted] per barrel. Figure VIII-1 summarizes this consumption.

Figure VIII-1. Summary of Heavy Fuel Oil Purchases and Consumption

	2016		2017		Total	
	Barrels	Cost	Barrels	Cost	Barrels	Cost
HFO Purchased	[redacted]					
HFO Used						
$/Barrel Used						

VIII.B.1.c. HFO Inventory

NSPI's approach to HFO inventory management is laid out in the Fuel Manual.[2] NSPI has 420,000 barrels of HFO storage capacity at Tufts Cove, where all HFO vessel shipments arrive.[3] HFO is viscous and needs to be kept heated to be pumped and burned. NSPI personnel stated that HFO is kept heated during the winter, but not during the summer, when gas is generally available and gas prices are

1 This is a commonly used price reference in the eastern United States and Canada and reflects the price assessment for a bulk cargo of HFO. Platts also publishes price assessments for barge and tank car lots, both of which tend to be more expensive than the cargo posting.

2 NSPI Fuel Manual Revision 10, section 7.4.2.

3 NSPI Fuel Manual Revision 10, section 7.4.2.

moderate. Vessel shipments arrive in 275,000 barrel amounts; therefore, NSPI seeks a vessel delivery when the forecasted HFO inventory is approximately 145,000 barrels.[4]

Figure VIII-2 below provides a detailed look at HFO inventory levels at Tufts Cove, which is the destination point of all HFO vessel shipments to NSPI. Note that at no point during the Audit Period did inventory levels at Tufts Cove dip below 145,000 barrels, which is in line with the Fuel Manual guidelines.

Figure VIII-2. End-of-Month HFO Inventories at Tufts Cove (Barrels)

[redacted]

Figure VIII-3 provides additional detail of NSPI's HFO inventories, showing monthly inventory levels at Lingan, Point Tupper, and Trenton. Note that there is very little movement in these levels due to the limited use of HFO at the solid fuel-fired plants.

4 NSPI Fuel Manual Revision 10, section 7.4.2.

Figure VIII-3. End-of-Month HFO Inventories at Lingan, Point Tupper, and Trenton (Barrels)

[redacted]

VIII.B.2. Light Fuel Oils

NSPI uses two kinds of LFOs: first, NSPI uses diesel fuel, or fuel oil #2, for combustion turbine generators, including at Burnside, Tusket, and Victoria Junction; and second, furnace oil for start-up and shut-down of fuel-milling systems and main boilers at its solid fuel-fired generators. For the Audit Period, NSPI spent [redacted] on diesel and [redacted] on furnace oil, representing [redacted] and [redacted] of total FAM expenditures, respectively.

VIII.B.2.a. LFO Procurement

All LFO purchased by NSPI during the Audit Period was from a single supplier, [redacted]. The contract with [redacted]—executed in 2014—allows NSPI to purchase a variety of light fuel oils from [redacted], including both furnace oil and diesel. NSPI states that the contract with [redacted] was awarded pursuant to an LFO RFP issued every three years, with extension rights. NSPI executed the contract on July 1, 2014, with an initial term through March 31, 2017. This contract renewed automatically for one year.

The price for LFO under the contract changed daily based on the supplier's posted rack price, which was correlated with the CME New York Harbor index for ultra-low sulphur diesel fuel, [redacted]. There was a separate adder (+/–) for deliveries to each of NSPI's plants, including Trenton, Lingan, Point Aconi, Point Tupper, Tufts Cove, and the combustion turbines.

The contract had no minimum purchase requirements, and LFO was ordered by the generation plants, as needed. We provide data on consumption, deliveries, and inventory in the following subsections.

VIII.B.2.b. LFO Consumption

Based on an aggregation of plant-level data over the audit period, [redacted] LFO, across all generating plants that used LFO, at a total cost of [redacted]. These data are shown below in Figure VIII-4; the numbers compare to [redacted] at a total cost of [redacted], as reported in the 2016 and 2017 FAM reports.

Figure VIII-4. Summary of Light Fuel Oil

	2016		2017		Total	
	Barrels	Cost	Barrels	Cost	Barrels	Cost
LFO Purchased	[redacted]					
LFO Used						
$/Barrel Used						

VIII.B.2.c. LFO Inventory

NSPI's approach to LFO inventory management is set out in the Fuel Manual.[5] LFO storage capabilities at each plant vary, and NSPI uses day-ahead delivery supply contracts to manage LFO requirements at each plant.[6] NSPI seeks to maintain significant inventories of diesel fuel for consumption at the combustion turbines.

Figure VIII-5, Figure VIII-6, and Figure VIII-7 provide detail of LFO (diesel) inventory at NSPI's combustion turbines. These units must maintain fuel on site to be reliable during peak hours. Recall that there are four Burnside units totaling 132 MW, two Victoria Junction units totaling 66 MW, and one 33 MW Tusket unit.

Figure VIII-5. Burnside LFO Purchases, Burned, and Ending Inventory, by Quarter (Barrels)

Burnside	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Purchases	[redacted]							
Consumption								
Ending Inventory								

5 NSPI Fuel Manual Revision 10, section 7.4.2.

6 NSPI Fuel Manual Revision 10, section 7.4.2.

Figure VIII-6. Victoria Junction LFO Purchases, Burned, and Ending Inventory, by Quarter (Barrels)

Tusket	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Purchases	[redacted]							
Consumption								
Ending Inventory								

Figure VIII-7. Tusket LFO Purchases, Burned, and Ending Inventory, by Quarter (Barrels)

Victoria Junction	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Purchases	[redacted]							
Consumption								
Ending Inventory								

VIII.B.3. Liberty 2014–2015 Recommendations

The previous fuel auditor had a single recommendation in its most recent audit report related to fuel oil. Liberty recommended that NSPI "[i]mpose more rigor in bidding practices for oil."[7] NSPI disagreed with this recommendation, noting that Liberty had withdrawn its concern and related recommendation.[8]

VIII.C. Conclusions

Conclusion VIII-1: HFO purchases followed typical utility procurement practices, and prices were indexed to independent price assessments.

Conclusion VIII-2: Price quotes included delivery by tanker, which required the supplier to bear the risk of chartering tankers, effect delivery of the HFO, and cover other potential losses occurring prior to delivery.

Conclusion VIII-3: Independent admiralty services were employed to verify that HFO deliveries met specified quantities and specifications.

Conclusion VIII-4: Analyses of HFO proposals was thorough and vetted by the required process. Proposed pricing reflected then-market prices, and NSPI selected the lowest price at an acceptable level of delivery risk.

7 Liberty 2014-2015 Audit Report, page V-23.

8 NSPI 2016 FAM Audit Action Plan, January 31, 2016, page 11.

Conclusion VIII-5: Given the relatively small quantities of LFO required, NSPI's approach to letting a blanket contract for LFO, and enabling the separate generation plants order LFO as needed, appears reasonable.

Conclusion VIII-6: LFO prices were tied to [redacted] daily posting of rack prices by product, which vary by location across Canada. This is seen as a cost-effective way to procure needed LFO and reduced the need for NSPI to maintain, or contract for, a trucking fleet to effect deliveries.

Conclusion VIII-7: NSPI's contracts for HFO, LFO, and related services contained important protections for NSPI and FAM customers, including required technical specifications of oil products, no minimum delivery quantities, and non-exclusive clauses that allowed NSPI to contract with other suppliers if necessary.

Conclusion VIII-8: HFO and LFO inventory management appeared reasonable during the Audit Period and was in line with guidance in the Fuel Manual.

VIII.D. Recommendations

None.

IX. Power Plant Performance

IX.A. Background

In this chapter, we look at the performance of NSPI's thermal generation fleet. This is an important chapter for a number of reasons. First, NSPI's thermal fleet provides a substantial portion of NSPI's total system requirements—in 2016, the thermal fleet provided 7,767,056 MWh, or 71.7% of the net system requirement,[1] while in 2017, it provided 7,603,909 MWh, or 69.3%.[2] Second, unlike wind turbines or third-party power purchases, the thermal fleet's performance is something that NSPI can, to a large degree, control. Prudent operations and maintenance practices can lead to better generator performance, which can mean more optimal economics for NSPI ratepayers. Third, NSPI's generation fleet is under pressure on two fronts: (1) from the relatively high penetration of variable generation, which requires different operating characteristics than those possessed by many of NSPI's thermal generators, and (2) on the regulatory front, as the Board, stakeholders, and others are actively reviewing NSPI's seemingly large generation portfolio, which requires annual expenditures for upkeep and on which NSPI earns an annual rate of return.[3]

Our purpose in this chapter is to examine the performance of NSPI's generation fleet over the Audit Period, as measured by standard industry metrics and benchmarks. We review NSPI's outage management process and provide details on outages observed during the Audit Period. We provide details about the costs involved in maintaining the generation fleet as it is currently constituted. We provide our review of the size of NSPI's generation fleet. We summarize the information gathered at our power plant visits. And, we provide conclusions and practical recommendations that NSPI can institute going forward to economically transition its portfolio.

Some of our recommendations may not apply directly to this Audit Period. However, it is important to recognize the relationship between resource planning and FAM costs. That is, today's resource decisions influence tomorrow's FAM costs. Accordingly, in this chapter, we are recommending changes to NSPI's resource planning process, as that could help mitigate fuel costs in the future.

NSPI's thermal generation fleet consists of four coal-fired plants: the four-unit Lingan plant, totaling 612 MW; the two-unit Trenton Plant, totaling 304 MW; the lone 150 MW unit at Point Tupper; and the 168 MW unit at Point Aconi, which uses fluidized bed combustion to burn a solid fuel blend that is primarily petcoke, plus coal. NSPI's other solid-fuel fired plant is the 43 MW biomass facility at PHP. NSPI's fleet includes six units at the Tufts Cove plant. Tufts Cove 1, 2, and 3 are natural gas-fired steam

1 Based on a total system requirement of 10,809,091 MWh. See NSPI's Q4 2017 FAM Report, Q-6.
2 Based on a total system requirement of 10,873,274 MWh. See NSPI's Q4 2017 FAM Report, Q-6.
3 NSPI is also subject to pending governmental environmental regulations, which could have an impact on NSPI's generating fleet.

turbines (with the ability to fuel-switch to burn HFO) totaling 318 MW, while the remaining Tufts Cove units make up a 2x1 combined-cycle train, with Tufts Cove 4 and 5 being natural gas-fired gas turbines and Tufts Cove 6 being the heat-recovery steam turbine—together, the trains total 144 MW. Lastly, NSPI owns seven 33 MW LFO-fired jet engines: four at Burnside, two at Victoria Junction, and one at Tusket. Figure IX-1 provides additional detail on NSPI's thermal fleet.

Figure IX-1. NSPI's Thermal Generation Fleet

Power Plant	Maximum Winter Capability (MW)	Primary Fuel	Secondary Fuel	In-Service Year
Trenton 5	150	Coal	Heavy Fuel Oil	1969
Trenton 6	154	Coal	Heavy Fuel Oil	1991
Lingan 1	153	Coal	Heavy Fuel Oil	1979
Lingan 2	153	Coal	Heavy Fuel Oil	1980
Lingan 3	153	Coal	Heavy Fuel Oil	1983
Lingan 4	153	Coal	Heavy Fuel Oil	1984
Point Aconi	168	Petcoke/Coal	Light Fuel Oil	1993
Point Tupper	150	Coal	Heavy Fuel Oil	1973
Tufts Cove 1	78	Natural Gas	Heavy Fuel Oil	1965
Tufts Cove 2	93	Natural Gas	Heavy Fuel Oil	1972
Tufts Cove 3	147	Natural Gas	Heavy Fuel Oil	1976
Tufts Cove 4	49	Natural Gas	-	2003
Tufts Cove 5	49	Natural Gas	-	2004
Tufts Cove 6	46	Natural Gas	-	2012
Port Hawkesbury	43	Biomass	Natural Gas	2013
Tusket 4	33	Light Fuel Oil	-	1971
Victoria Junction 1	33	Light Fuel Oil	-	1975
Victoria Junction 2	33	Light Fuel Oil	-	1976
Burnside 1	33	Light Fuel Oil	-	1976
Burnside 2	33	Light Fuel Oil	-	1976
Burnside 3	33	Light Fuel Oil	-	1976
Burnside 4	33	Light Fuel Oil	-	1976
Total	**1,970**			

In addition to the thermal fleet listed above, NSPI also owns hydro and wind resources, which total 399 MW and 81 MW of nameplate capacity, respectively. In total, then, NSPI's generating fleet capacity is 2,450 MW. Figure IX-2 shows NSPI's hydro and wind fleet.

Figure IX-2. NSPI's Hydro, Wind Resources[4]

Power Plant	Nameplate Capacity (MW)	Generation Type	In-Service Year
Annapolis 1	19.9	Hydro	1984
Avon 1	3.75	Hydro	1958
Avon 2	3.5	Hydro	1929
Fourth Lake 1	3	Hydro	1983
Gulch 1	7.5	Hydro	1952
Ridge 1	4	Hydro	1957
Hells Gate 1	3.36	Hydro	1930
Hells Gate 2	3.57	Hydro	1949
Hollow Bridge 1	5.3	Hydro	1942
Lumsden 1	2.8	Hydro	1940
Methals 1	3.4	Hydro	1949
White Rock 1	3.2	Hydro	1952
Dickie Brook 1	1.2	Hydro	1948
Dickie Brook 2	2.6	Hydro	1948
Fall River 1	0.5	Hydro	1985
Lequille 1	11	Hydro	1968
Big Falls 5	5.3	Hydro	1929
Big Falls 6	5.3	Hydro	1929
Cowie Falls 11	3.8	Hydro	1938
Cowie Falls 12	3.6	Hydro	1938
Deep Brook 10	4.6	Hydro	1950
Deep Brook 9	4.5	Hydro	1950
Lower Great Brook 7	2	Hydro	1955
Lower Great Brook 8	1.9	Hydro	1955
Lower Lake Falls 3	3.69	Hydro	1929
Lower Lake Falls 4	3.5	Hydro	1929
Upper Lake Falls 1	2.6	Hydro	1929
Upper Lake Falls 2	2.8	Hydro	1929
Nictaux 1	6.8	Hydro	1954
Paradise 1	3.6	Hydro	1950
Harmony	0.75	Hydro	1943
Roseway 1	0.45	Hydro	1974
Roseway 2	0.6	Hydro	1949
Malay Falls 4	1.2	Hydro	1924
Malay Falls 5	1.2	Hydro	1924
Malay Falls 6	1.2	Hydro	1924
Ruth Falls 1	2	Hydro	1925
Ruth Falls 2	2	Hydro	1925
Ruth Falls 3	2.97	Hydro	1936
Sissiboo 1	6.2	Hydro	1961
Weymouth 1	9.5	Hydro	1961
Weymouth 2	9.5	Hydro	1967
Mill Lake 1	1.3	Hydro	1922
Mill Lake 2	1.1	Hydro	1922
Sandy Lake 3	1.8	Hydro	1928
Sandy Lake 4	1.8	Hydro	1928
Tidewater 1	2	Hydro	1922
Tidewater 2	2.2	Hydro	1922
Tusket 1	0.8	Hydro	1929
Tusket 2	0.8	Hydro	1929
Tusket 3	0.8	Hydro	1929
Gisbourne 1	3.75	Hydro	1982
Wreck Cove 1	106	Hydro	1978
Wreck Cove 2	106	Hydro	1978
Digby	30	Wind	2010
Grand Etang	0	Wind	2002
Little Brook	0	Wind	2002
Nutby Mountain	50.6	Wind	2010
Total	**479**		

4 Nameplate capacity listed in Figure IX-2 is the maximum net winter capacity. NSPI also jointly owns the South Canoe and Sable Island wind farms; see the Power Purchases and Sales chapter.

IX.B. Findings

IX.B.1. Contextual Analysis of NSPI's Thermal Generation Fleet

NSPI's generation mix includes a high penetration of wind capacity coupled with a thermal fleet that is not optimal for addressing the operational challenges of a wind-heavy resource portfolio. We note that NSPI's wind penetration by some measures is among the highest in North America. Figure IX-3 illustrates this point.

Figure IX-3. Comparing NSPI's Wind Penetration to Other Electric Systems

Region	Percent of Net Generation Provided by Wind (2016)
Nova Scotia	**17.0**
CAISO	9.5
ERCOT	14.0
MISO	7.0
New England	2.4
New York	2.8
PJM	2.2
SPP	15.6

Making matters more challenging is the fact that NSPI's load can be low at times—almost as low as its 597 MW of wind capacity. In 2016, NSPI's minimum load in a given hour was 669 MW; in 2017, that number was 693 MW. As we explain in the chapter on Purchased Power and Sales, NSPI's wind PPAs and wind COMFIT agreements—which make up a significant majority of NSPI's 597 MW of contracted wind—are effectively "take or pay" agreements, meaning that NSPI is obligated to absorb the energy output of those wind resources at a fixed, contractual rate, with no ability to curtail for economic reasons.

The additional wind generation in Nova Scotia has disparate impacts on NSPI's needs. In terms of production of *energy*, as measured in MWh, wind displaces energy that would have been provided by other sources, in particular, from NSPI's thermal generation fleet. However, in terms of *capacity*, wind displaces a minimal amount of NSPI's need. Overall, NSPI ratepayers benefit from the additional wind generation in that total emissions from the generation needed to serve NSPI customers is decreased; however, this comes at a cost, as the average cost of wind per MWh under NSPI's existing wind PPAs is higher than the average cost of output from NSPI's thermal units. Moreover, because of the minimal capacity value of the wind generation and because electric generation planning is done based on capacity value, NSPI must retain thermal generation capacity for reliability purposes, which means maintenance costs and other "sustaining capital" are needed to keep those plants in operation.

NSPI's thermal generation fleet is also not optimally suited for the operational challenge of backing up such substantial levels of fluctuating wind generation. Wind-heavy systems are best paired with flexible power generators, such as natural gas-fired combined cycle, combustion turbines, natural gas-fired jet engines, and flexible hydroelectric resources, as well as energy storage. While NSPI does have some resources that are helpful to system operators in managing the wind on the system, such as the Wreck Cove and Tufts Cove units, much of NSPI's thermal fleet is inflexible generation fired by solid fuel. This is shown in Figure IX-4 below; specifically, NSPI's thermal units all have ramp rates of 2.00 MW/minute or less—only the Tufts Cove Units 4, 5, and 6 have ramp rates higher than that. For reference, modern, gas-fired, combined cycle generators have average ramp rates of 15–25 MW/minute[5] or more.[6]

Figure IX-4. Ramp Rates of NSPI's Thermal Generating Units

Thermal Plant	Ramp Rate (MW/Minute)
Tufts Cove 4	5.00
Tufts Cove 5	5.00
Tufts Cove 6	3.50
Trenton 6	2.00
Lingan 1	2.00
Lingan 2	2.00
Lingan 3	2.00
Lingan 4	2.00
Point Tupper	2.00
Tufts Cove 2	2.00
Tufts Cove 3	2.00
Trenton 5	1.75
Point Aconi	1.00
Tufts Cove 1	1.00
Port Hawkesbury	1.00

The impact of high wind penetration and displacement of energy output on NSPI's thermal generating fleet is demonstrated through reduced capacity factors, which we show and discuss below. However, the impact of wind on NSPI's thermal fleet also manifests itself in not just lower capacity factors but also a different approach to operating these units. Specifically, these units must be "cycled"—that is, turned "on" and "off" more frequently, ramped up and down more often, and ramped faster—rather than run as baseload facilities, as they were originally designed to do. Besides the impact on capacity factors, this approach can have negative impacts on the thermal plants themselves, including increased fatigue on plant components, higher capital and operational costs, increased forced outage rates, and reduced plant life.[7] It can also lead to poorer emissions performance over time.[8] For its part, NSPI has implemented a

[5] Steven Macmillan, Alexander Antonyuk, and Hannah Schwind, "Gas to Coal Competition in the U.S. Power Sector" (International Energy Agency Insights Series 2013), 14, *available at* https://www.iea.org/publications/insights/insightpublications/CoalvsGas_FINAL_WEB.pdf.

[6] Miguel Angel Gonzalez-Salazar, et al., "Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables," *Electricity Journal*, 82, Part 1, February 2018 ("*Electricity Journal* Article"), Table 2, *available at* https://www.sciencedirect.com/science/article/pii/S1364032117309206#bib2. See also GE Power, "LM6000 Power Plants," *available at* https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/product/gas%20turbines/Fact%20Sheet/2018-prod-specs/LM6000-power-plants.pdf.

[7] *Electricity Journal* Article.

[8] *Electricity Journal* Article.

comprehensive asset management program—aspects of which we address later in this chapter—to help address these challenges.

IX.B.2. Further Context: A Primer on Short-Term, Long-Term Resource Adequacy

In the electricity industry, "reliability" is a broad term defined as "the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components."[9] A key aspect of reliability is "resource adequacy," which is defined as "[t]he ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."[10] There are two aspects of resource adequacy for which we provide a brief primer to frame the rest of this chapter.

The first aspect is "short-term" resource adequacy—i.e., day-to-day resource adequacy that ensures there are sufficient generation units online and in reserve to enable the system to operate reliably and protects against load variations, forecast errors, and system contingencies, such as equipment failure.[11] In general, short-term resource adequacy is achieved by having sufficient generating resources online to cover both load and operating reserve requirements. Operating reserves are "[t]hat capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and schedule outages and local area protection."[12] Utilities are typically required by NERC and its regional reliability authorities to carry a certain amount of operating reserves at all times. (NSPI is no exception, and we provide detail on this point below.)

The second we define as "long-term" resource adequacy—i.e., to determine if there are adequate supply of resources to meet forecasted peak need over a multi-year planning horizon (e.g., one-year, ten-year, etc.). This is an important measure of a utility's reliability because building a power plant takes time, so utilities plan ahead to see how much supply will be needed, and when.[13] Here, the "reserve" measure is "planning reserves," which are supply in excess of forecasted peak demand at a given point in the future (e.g., five years from now).

To expand further on this idea of long-term resource adequacy, we note that electric utilities forecast their expected demand, focusing in particular on the "peak" demand, for a given time period, that is, the maximum amount of forecasted demand in a given hour over a given time period. Utilities also determine a margin of safety—a so-called "planning reserve margin"—that provides utilities with a cushion of additional supply to account for the uncertainties of supply, demand, transmission, and other variables

9 US Department of Energy, "Ensuring Electricity System Reliability, Security, and Resilience," 2017, 4-3, *available at* https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

10 NERC Glossary of Terms, *available at* https://www.nerc.com/files/glossary_of_terms.pdf.

11 See, e.g., PJM, "Reserves Scheduling, Reporting and Loading RE Module," *available at* http://www.pjm.com/~/media/training/nerc-certifications/RE1-reserve.ashx.

12 NERC Glossary of Terms.

13 National Renewable Energy Laboratory, "Comparing Resource Adequacy Metrics," September 2017, 1, *available at* https://www.nrel.gov/docs/fy14osti/62847.pdf

that can impact an electric system. The sum of these two numbers—forecasted peak demand and the planning reserve margin—determine the amount of supply that the utility will need to be adequate—and thus reliable—for a given time period.

A number of factors go into an electric utility's planning reserve margin, including (1) technical resource adequacy criteria, such as "loss of load expectation," which is a probabilistic measure of the expected number of outage hours in a given time period; (2) regulatory policy; and (3) electric utility planning and procurement processes.[14] NERC provides guidance by issuing an annual assessment of North American resource adequacy by region, providing both a target or "reference" level of planning reserves and an expected level of actual reserves, based on current status and projections. Reference levels are established to allow NERC to assess the level of planning reserves, recognizing factors of uncertainty involved in long-term planning, such as unplanned electric generator outages, extreme weather impacts, generator fuel availability, and intermittency of variable generation.[15] In the end, while it is true in theory that a higher planning reserve margin will increase resource adequacy and reliability, system costs and risk averseness of regulators and end-use customers determine how much additional margin to pursue.[16]

One example of an electric utility considering both technical reliability metrics and economic cost in proposing a planning reserve margin is PacifiCorp, an electric utility that serves customers in six western US states. As part of its Integrated Resource Planning process, PacifiCorp conducts a planning reserve margin study, in which PacifiCorp looks at 10 different planning reserve margin levels—from 11% to 20%—and conducts a stochastic model to assess both the reliability and economic results of the different planning margin reserve levels.[17] Based on this analysis—which looks at both the increase in reliability associated with each planning reserve margin level, but also its cost—PacifiCorp chooses a planning reserve margin.[18]

The key distinction here is that short-term resource adequacy looks at generation that is online and in reserve to meet system demand in the real-time and day-ahead time horizon, in all hours, plus operating reserve. That means as load rises and falls, the amount of generation online and in reserve ideally rises and falls to meet it, to maintain reliability and minimize cost. Long-term resource adequacy looks at capacity adequacy over a long-term time horizon—years in advance, in some cases—assessing whether capacity is sufficient to meet forecasted peak demand, plus a planning reserve margin. Here, peak load is what matters, not the day-to-day rising and falling of load or forecasted load.

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14 North American Electric Reliability Corporation, "2017 Long-Term Reliability Assessment," 2017, 25, *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf

15 *Id.*

16 *Id.*

17 Pacificorp, "2017 Integrated Resource Plan, Appendix I – Planning Reserve Margin Study ("Pacificorp IRP")," April 4, 2017, pages 167–169.

18 *Id.*, page 169.

IX.B.3. Utilization of NSPI's Thermal Generation Fleet

IX.B.3.a. Short-Term Utilization: Less Energy, More Operating Reserves

Audit Period data suggest NSPI's thermal generation fleet is being used over the short-term to provide less energy and more operating reserves than it did prior to increases in wind penetration in Nova Scotia. We provide three data points to support this assertion: the capacity factor data for the fleet; the number of hours each thermal generator operated at its "minimum" operating level during the Audit Period; and the hourly operating reserve data for the Audit Period.

Beginning with capacity factor, Figure IX-5 provides the net capacity factors for each thermal unit over the two years of the Audit Period. Capacity factor measures the amount of actual output from a generator compared to its maximum potential output during a given period.

Figure IX-5. Net Capacity Factors, NSPI Thermal Generating Units

Thermal Plant	2016 Capacity Factor	2017 Capacity Factor
Point Aconi	73.81%	74.08%
Point Tupper	76.24%	69.92%
Trenton 6	78.50%	66.16%
Trenton 5	55.06%	61.81%
Lingan 3	50.42%	55.24%
Tufts Cove 4	57.93%	54.30%
Tufts Cove 5	55.96%	49.11%
Lingan 1	56.63%	45.12%
Lingan 4	37.52%	43.19%
Point Hawkesbury	56.71%	40.50%
Tufts Cove 1	5.57%	38.78%
Tufts Cove 2	22.79%	35.34%
Tufts Cove 3	46.27%	30.43%
Tufts Cove 6	32.93%	28.29%
Lingan 2	22.54%	22.75%

Figure IX-5 demonstrates that for much of NSPI's fleet, the net capacity factors are lower than NSPI's historical capacity factors. For example, in 2007, prior to the arrival of significant wind generation resources in Nova Scotia, NSPI's coal-fired generating fleet had a combined capacity factor of almost 90%.[19] During this Audit Period, three units (Point Tupper, Point Aconi, and Trenton 6) had years with net capacity factors above 70%, while three units (Lingan 1, 2, and 4) had years with net capacity factors below 50%.

We next turn to data on NSPI's thermal fleet loading levels, focusing our review of actual output of the units. Specifically, we reviewed the data to determine how often units were being dispatched at their "economic minimum" operating level, which is the minimum megawatt amount of electric energy

19 Liberty 2014-2015 FAM Audit Report, page VIII-12.

available from a generating resource for economic dispatch.[20] Economic minimums vary by unit. Figure IX-6 shows the economic minimum dispatch level for each of NSPI's thermal generators fired by coal or petcoke and provides the percentage of hours those units were dispatched at or below economic minimum. These units are instructive, as they are typically and historically baseload units that would rarely be operated at economic minimum or below.[21]

Figure IX-6. Percentage of Hours NSPI's Thermal Units Operated at Economic Minimum (or Lower) During Audit Period[22]

Thermal Plant	Economic Minimum (MW)	% of Hours Operating at or below Eco Min (Excluding 0 MW hours)	% of Hours Operating at or below Eco Min (Including 0 MW Hours)
Lingan 2	60.00	0.95	67.09
Lingan 4	60.00	1.31	46.86
Lingan 1	60.00	0.74	26.86
Lingan 3	60.00	2.27	22.48
Point Aconi	130.00	8.81	22.16
Trenton 5	60.00	0.87	21.59
Trenton 6	70.00	2.35	19.0
Point Tupper	60.00	0.31	11.12%

The implication of the previous two tables is clear: NSPI's thermal generators are providing less *energy* than they did before the introduction of significant wind generation in Nova Scotia. To further underscore this point, we look to data on operating reserves. NSPI must carry operating reserves consistent with the requirements of NPCC, NSPI's regional reliability authority.[23] NSPI carries three operating reserve products in every hour of every day to help meet these requirements. Those three products are 30-Minute Reserve,[24] 10-Minute Reserve,[25] and Synchronized Reserve.[26] These combined operating reserves are meant to ensure reliable operation in the event of unexpected generation or transmission problems that require additional generation to start producing energy in a short period of time. As is shown in Figure IX-7, NSPI enjoyed surpluses of operating reserves throughout the Audit Period.

20 See, e.g., ISO New England's FAQs on Generator Operational Parameters, *available at* https://www.iso-ne.com/participate/support/faq/generator-operational-parameters.

21 Liberty 2014-2015 FAM Audit Report, page VIII-12.

22 The hours in Column 3 do not include any "zero" output hours—these are only non-zero hours of production. Notably, Lingan 2's results appear positive; however, Lingan 2 does not operate for much of the year between April and November, logging "zero" output hours during that time. Zero output hours are captured in Column 4.

23 NSPI 10-Year System Outlook – 2016 Report, section 8.1. NSPI must carry enough 10-minute reserve to cover its largest single contingency and enough 30-minute reserve to at least equal half of its second largest contingency.

24 On a day-ahead basis, NSPI carries at least 75 MW of 30-Minute Reserve.

25 On a day-ahead basis, NSPI carries at least 168 MW to 171 MW of 10-Minute Reserve, based on Point Aconi's net plant rating (as Point Aconi is NSPI's single largest contingency). On an intra-day basis, NSPI carries at least 168 MW to 171 MW of 10-Minute Reserve as well.

26 On both a day-ahead and intra-day basis, NSPI carries at least 32–33 MW of Synchronized Reserve.

Figure IX-7. NSPI's Average Operating Reserve Surpluses[27]

Operating Reserve Type	Maximum Requirement (MW)	2016 Average (MW)	2017 Average (MW)	Average Excess (MW)
30-Minute Reserve	75	546	558	477
10-Minute Reserve	171	443	441	271
Total Operating Reserve	246	546	558	306

Again, the implication is clear: NSPI's thermal generating fleet is being relied upon less for energy and more for backup reserves and load following. The question of whether the reserve surpluses shown in Figure IX-7 are excessive or appropriate is a question we address in our chapter on Economic Commitment and Dispatch.

IX.B.3.b. Long-Term Utilization: Meeting Peak Load and Planning Reserve Margin

To determine if NSPI has excess capacity, that is, *too many generating units,* short-term data on operating reserves, capacity factors, and other operational measures are less useful. Instead, as we note above, long-term resource adequacy is what is important because it considers capacity adequacy over a long-term time horizon—years in advance, in some cases—assessing whether capacity is sufficient to meet forecasted peak demand, plus a planning reserve margin. Here, peak load is what matters, not the day-to-day rising and falling of load or forecasted load.

NERC provides guidance on planning reserve margins by issuing an annual assessment of North American resource adequacy by region, providing both a target or "reference" level of planning reserves and an expected level of actual reserves, based on current status and projections. Reference levels are established to allow NERC to assess the level of planning reserves, recognizing factors of uncertainty involved in long-term planning, such as unplanned electric generator outages, extreme weather impacts, generator fuel availability, and intermittency of variable generation.[28] The NPCC requires NSPI to "demonstrate that the loss of load expectation…of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."[29]

Today, NSPI uses a planning reserve margin of 20% above its peak load. NSPI's planning reserve margin is consistent with its regional reliability authority area—the NPCC Maritimes—which also has a 20% planning reserve margin. NPCC Maritimes has one of the highest planning reserve margins in North America, where NERC's current reference planning reserve margins range between 10.6% and 23.7% for the various North American regions.[30]

NSPI explained that it evaluates its planning reserve margin only when it conducts an IRP, or when "major system resource changes take place." NSPI does not conduct IRP updates on a regular schedule,

[27] 30-Minute Average Reserves include 10-Minute and Synchronized Reserve Margins.

[28] North American Electric Reliability Corporation, "2017 Long-Term Reliability Assessment," 2017, 25.

[29] NPCC, Inc., "Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System," September 30, 2015, R4, *available at* https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf.

[30] North American Electric Reliability Corporation, "2017 Long-Term Reliability Assessment," 2017, Table 9.

but does conduct an annual 10-year outlook, which "confirms that the current planning reserve margin continues to meet the 0.1 days per year Loss of Load Expectation requirement of the NPCC reliability criteria using the PLEXOS modeling tool." This is an important distinction. In the annual 10-year planning outlook, NSPI confirms the *adequacy* of the 20% planning reserve margin; in the IRP planning process, NSPI assesses the *optimality* of its planning reserve margin. In the former case, cost is not considered; in the latter, cost is considered, and the tradeoff between cost and reliability is studied and considered in setting a planning reserve margin. Thus, implementing a regular IRP planning process would help determine if the 20% planning reserve margin is optimal for Nova Scotia. We make a recommendation to this effect later in this chapter.

Regarding peak load, the other crucial component of determining the right amount of resources needed in the future, NSPI forecasts that its peak load will grow at an average of about 1.1% between now and 2027.[31] As long as peak load grows, NSPI may need to *add* resources to the system, since the system is planned to meet peak needs (plus the planning reserve margin). Thus, it is important that NSPI's peak load forecast be fully vetted during the IRP planning process.

To help ensure that NSPI's resource fleet meets NERC and NPCC requirements without being over capacity, we make several suggestions. First, the Board should require NSPI to conduct regular IRP planning. This will ensure that NSPI will be regularly determining the lowest planning reserve margin necessary to meet NPCC requirements, rather than just assessing if "20%" remains in compliance. Second, in the IRP planning process, the Board should fully vet NSPI's peak load forecast, which is particularly instrumental in determining the level of capacity needed going forward. Given that NSPI's peak load forecasts for the next 10 years may be discordant with those of NERC for the NPCC area, this will be a crucial step for the Board. Third, in the IRP process, the Board should require NSPI to consider all alternatives, including firm import capacity, transmission expansion, demand-side management, pumped hydro resources, additional hydro resources over the Maritime Link, natural gas infrastructure investments, and emerging technologies as alternatives to traditional maintenance of existing generation or expansion of NSPI's portfolio. DSM, for example, can provide benefits through peak load shaving, as can firm imports—which NERC describes as "capacity transfers"—from one control area to another. For the Audit Period, NSPI modeled zero capacity from imported sources; this will change with the energization of the Maritime Link but will be limited to 153 MW, and New Brunswick imports will remain "zero" for capacity purposes.[32] NSPI does have a reserve sharing agreement with New Brunswick, but that agreement is for short-term *operating* reserves, not long-term planning reserves. Other regions—like Southwest Power Pool—have been successful in reducing their planning reserve margins through transmission investment and footprint expansion.[33] Every MW of firm, import capacity (or DSM) capacity displaces the need for capacity from NSPI's existing fleet. Fourth, the effect of PHP load should

[31] NSPI 2017 10 Year System Outlook, Figure 24.

[32] NSPI, "Capacity Value of Wind Assumptions and Planning Reserve Margin," April 23, 2014, slide 31.

[33] See SPP, "SPP Board Votes to Lower Planning Reserve Margins, Award First Competitively Bid Project, Approve $363M in Transmission Upgrades," April 26, 2016, *available at* https://www.spp.org/about-us/newsroom/spp-board-votes-to-lower-planning-reserve-margins-award-first-competitively-bid-project-approve-363m-in-transmission-upgrades/.

be addressed explicitly in the IRP evaluation process. As noted in the final chapter of this report, the LRT requires that NSPI exclude PHP from its planning considerations. NSPI should assess the effect of incorporating PHP load in resource planning to ensure that PHP load does not impose net costs on FAM customers over a longer time horizon.

The resource alternatives noted above have a cost, of course, but those costs (and associated benefits) are best assessed and vetted in the IRP process. To that end, our fifth suggestion is to ensure that the IRP process allows for Board and stakeholder review and input. IRPs are only as useful as the assumptions that drive them, so it is important that NSPI's IRP methodology and assumptions be vetted by third parties and experts. Sixth, NSPI should continue to evaluate the firm capacity value of new and existing wind resources. Today, NSPI's wind resources are assigned capacity value of no more than 17% of their nameplate capacity, and in the past, received as little as zero capacity value. This is an assumption that should be continually reviewed during the regular IRP process and should be done using an effective load carrying capability study process, as NSPI has used in the past.

Given our access to Audit Period data, and the dynamic and important nature of determining a reasonable capacity value for wind generation, we conducted a highly simplified analysis of about 412 MW of Nova Scotia wind generation[34] at peak hours during the Audit Period. Our purpose was not to introduce information that would displace or diminish reliance on a robust effective load carrying capability study; again, use of such a study is industry standard. Instead, we simply sought to determine if, during the Audit Period, wind capacity factors were correlated with peak demand hours, which we might expect to see in a winter-peaking system like NSPI's. In our analysis, we saw that, on average, wind output during the 52 peak hours of the two-year Audit Period—with load at 1,875 MW or higher—was about 218.5 MW, implying a capacity factor of 53%. This is shown in Figure IX-8.

Figure IX-8. Implied Capacity Factor of Nova Scotia Wind during 52 Highest Peak Hours of Audit Period

Wind Farm	Average Output During Peak Hours	Nameplate Capacity	Implied Capacity Factor
Gullivers	23.39	30.0	77.98%
Dalhousie	32.99	51.0	64.69%
South Canoe	59.59	102.0	58.42%
Amherst	16.09	30.0	53.63%
Glen Dhu	33.30	62.1	53.63%
Lingan	7.36	14.0	52.60%
Pt. Tupper	11.50	22.0	52.29%
Nuttby	19.74	50.6	39.01%
Maryvale	2.21	6.0	36.76%
Pubnico Point	9.93	30.6	32.46%
Sable	2.29	13.8	16.61%
Total	**218.40**	**412.10**	**53.00%**

We are not suggesting that NSPI adopt this number; a complete effective load carrying capability analysis of an appropriate capacity value for wind generation is far more complex than our simple

34 The wind farms listed in Figure IX-8 are the only wind farms that NSPI has SCADA-level data that allow for hourly output amounts. All other wind farm output data are aggregated into monthly data.

analysis above, and is an industry standard approach. Indeed, NSPI has conducted such analyses in the past.[35] We put this simple analysis forward for two reasons. First, it implies some good news—that is, that wind generation may be positively correlated with the highest peak hours during NSPI's winter peak. Second, given the advancements in wind technology, wind capacity factors continue to rise, suggesting that utilities should (and typically do) regularly assess their assumptions. We provide a recommendation below that includes this suggestion, as well as the others related to the IRP process.

IX.B.3.c. Underscoring the Point: Assessing an Average Hour in Nova Scotia

To demonstrate the impact of wind on NSPI's system and its effect on NSPI's short-term and long-term thermal fleet utilization, see Figure IX-1. The first bar in the figure—"Load"—is the sum of NSPI's average hourly load in 2017, plus required operating reserves. In other words, this first bar is the 2017 average of NSPI's energy and operating reserves demands on an hour-to-hour, short-term basis. The second bar—"Forecasted Peak"—is NSPI's forecasted peak load, plus a 20% reserve margin, for the 2017–2018 winter period.[36] This second bar represents the amount of capacity NSPI needs to be reliable in this period—that is, to meet forecasted peak demand, plus a planning reserve margin of 20%. The third bar—"Capacity"—is the total capacity of NSPI's generation fleet.[37]

[35] NSPI, "Capacity Value of Wind Assumptions and Planning Reserve Margin," April 23, 2014.

[36] Data taken from NSPI's 10-Year System Outlook – 2017 Report, Figure 24.

[37] Data taken from NSPI's 10-Year System Outlook – 2017 Report, Figure 24.

Figure IX-9. Comparison of NSPI's Average Load Plus Reserves Needs (2017 Data), Peak Demand Plus Planning Reserve Margin, and Total Generating Capacity

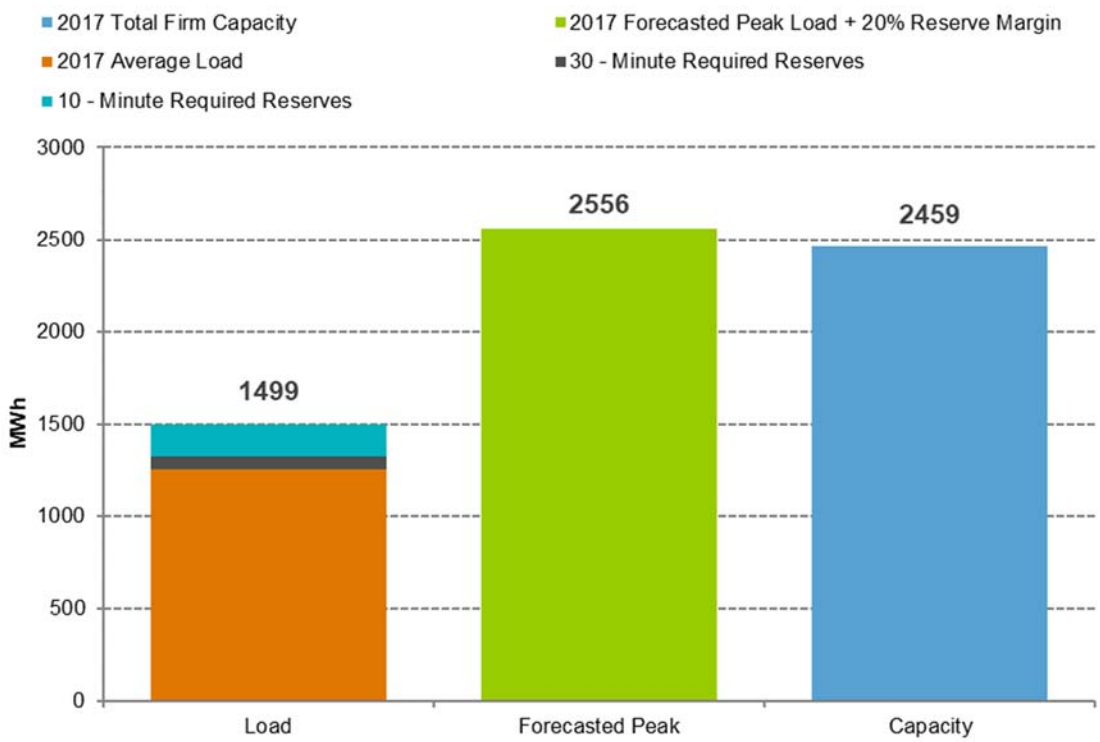


Figure IX-9 illustrates two important points. First, NSPI's capacity total of 2,459 MW is planned to meet the "Forecasted Peak" bar (which represents peak load, plus a 20% planning reserve margin), not the "Load" bar. NSPI appropriately plans for peak load plus a planning reserve margin—the average hourly energy and operating reserve needs is not considered in planning the generating capacity portfolio's adequacy. Second, Figure IX-9 helps illustrate the unsurprising result that NSPI's thermal fleet will likely observe lower capacity factors and lower loading levels and will contribute to a surplus of operating reserves. Consider that in an average hour in 2017, NSPI received at least 300 MWh from wind, IPP renewables, COMFIT, and hydro resources. That leaves about 1,200 MWh of energy and operating reserves needs, on average, during 2017, with a thermal fleet capable of providing 1,970 MWh in a given hour. This large difference between NSPI's capacity and its average hourly energy and operating reserve needs is not an indictment of the size of its generating portfolio, given its peak load and planning reserve margin. Rather, it helps explain why its thermal generating fleet has seen lower capacity factors and why the system has seen a surplus of operating reserves carried in the average hour. We address the merits of this latter issue in the Economic Commitment and Dispatch chapter.

IX.B.4. Analysis of Unit Performance

We reviewed each of NSPI's thermal generating units across a variety of industry standard metrics used to judge unit performance. The four metrics we examined were Availability Factor (AF), outage and de-rate data, de-rated adjusted forced outage rate (DAFOR), and Heat Rate. In each case, we compare NSPI's generating units' performance against an industry-standard benchmark—typically "GADS"[38] data from NERC across all generating units in North America that report their generating data. Moreover, in each case, we compare NSPI's individual unit performance against the applicable technology and vintage plant. We address each in turn below.

IX.B.4.a.i. Availability Factor

The first metric we examined was AF, which NERC defines as the percentage of hours a unit is available over all potential hours of a given period.[39] The higher the AF, the more available the unit was to generate electricity. Figure IX-10 shows the AF for each of NSPI's thermal units for both 2016 and 2017, as well as the industry average for each unit's respective technology type and size. For example, each Lingan unit is a coal-fired, 153 MW unit. Thus, the appropriate comparison for these units is to coal-fired units between 100 and 199 MW. Green boxes illustrate instances where NSPI's performance beat the industry average; red indicates the opposite.

Figure IX-10. Availability Factors of NSPI Thermal Generating Units (Compared to Industry Averages)[40]

Thermal Plant	Availability Factor (2016)	Availability Factor (2017)	GADS Standard
Lingan 1	98.6%	85.1%	84.8%
Lingan 2	98.9%	73.4%	84.8%
Lingan 3	98.0%	97.1%	84.8%
Lingan 4	64.2%	90.6%	84.8%
Point Aconi	85.3%	86.5%	84.8%
Point Tupper	94.3%	85.9%	84.8%
Port Hawkesbury	92.5%	81.6%	86.9%
Trenton 5	77.6%	88.7%	84.8%
Trenton 6	92.5%	75.0%	84.8%
Tufts Cove 1	43.3%	86.0%	85.4%
Tufts Cove 2	85.1%	76.6%	85.4%
Tufts Cove 3	91.6%	66.5%	83.4%
Tufts Cove 4	87.4%	94.6%	90.9%
Tufts Cove 5	90.4%	82.7%	90.9%
Tufts Cove 6	88.4%	89.9%	87.8%

Figure IX-10 shows that in most cases—18 of 30—NSPI's generating units had AFs that were higher than the industry average. In general, these are positive results. On the positive side, NSPI had several instances of generating units with AFs above 90% in a given year, including Lingan 1 (2016), Lingan 2 (2016), Lingan 3 (both years), Lingan 4 (2017), Point Tupper (2016), PHP (2016), Trenton 6 (2016),

[38] GADS stands for the Generator Availability Database System. The GADS database maintains operating histories on more than 7,700 generating units in North America. GADS is a mandatory industry program for conventional generating units that are 20 MW or larger. See: https://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

[39] NERC, "Appendix F – Performance Indexes and Equations."

[40] NERC's GADS does not have a category for biomass plants. Thus, we compared PHP to "All Plants" between 1 and 99 MW. For Tufts Cove units 1–3, we used Gas Primary as the comparative technology. For Tufts Cove units 4 and 5, we used Gas Turbine as the comparative technology. For Tufts Cove 6, we used Combined Cycle Block as the comparative technology.

Tufts Cove 3 (2016), and Tufts Cove 4 (2017). There were also several instances of AFs below 75% in a given year: Lingan 2 (2017), Lingan 4 (2016), Tufts Cove 1 (2016), and Tufts Cove 3 (2017).

Importantly, low AFs are not necessarily indicative of poor performance. Unlike forced outage metrics like DAFOR, lower availability is driven by outages of all kinds, including planned and maintenance outages, which are essential for efficient and reliable operation. A unit that goes down for a significant period of time for necessary, regular planned maintenance will see its AF fall. One way to better assess units with low AFs in a given year driven by planned maintenance is to consider the AF of that unit in the following year—that is, after the significant maintenance work, did the unit's AF increase? And did it beat the industry average?

Focusing on NSPI's results, we note that in 2016, the two units with particularly low AFs—Lingan 4 and Tufts Cove 1—were both down for significant periods due in part to planned outages. Lingan 4, with an AF of 64.2% in 2016, was mostly impacted by a lengthy maintenance outage. This outage was planned to occur for eight weeks and to include work on Lingan 4's boiler; instead, the outage lasted over 16 weeks, from April 2, 2016, through July 27, 2016. NSPI explained that during the planned outage, NSPI discovered other maintenance issues that could only be discovered when the unit was opened up for inspection. As a result, NSPI extended the outage to complete this additional maintenance, which prevented the need to conduct this maintenance at another time, which would have increased costs to customers. NSPI also explained that it could have completed all this work in the original planned outage timeframe, but doing so would have required significant resources (e.g., additional contractors, overtime payments, etc.). Lingan 4 also suffered forced outages in August and September of 2016. NSPI explained that these forced outages were unrelated to work done during the maintenance outage.

Tufts Cove 1, meanwhile, which had an AF of 43.3% in 2016, also had a significant planned outage event that extended beyond its original estimate. The planned outage, which included a major turbine refurbishment, was scheduled to last for seven weeks, but lasted over fourteen. As with Lingan 4, during the planned outage inspection, NSPI discovered other work that needed to be done, which extended the outage. Moreover, upon returning Tufts Cove 1 to service in October 2016, NSPI noticed vibrations during startup and other signs of suboptimal operations; working with the original equipment manufacturer General Electric (OEM), NSPI sought to balance the generator in November 2016 but decided in December 2016 that the unit required significant work to fully return it to service. During this outage, NSPI discovered that the turbines had been too tightly set, a decision made under advisement of the OEM. Once work was complete on Tufts Cove 1 in January 2017, the unit was returned to service again, but NSPI found that vibration levels remained elevated and above those observed before the 2016 turbine refurbishment work was done. NSPI conducted a root cause analysis and determined that fault lay with the OEM for advising NSPI's maintenance crews on the original turbine refurbishment work; that bad advice had led to further outages (described above, as well as forced outages, described in the DAFOR section) and to the excessive vibration of the unit once it was back in service in January 2017. As of the end of our discovery work in the audit process, the OEM was still assessing its own analysis of the incident; we note that the vibration of Tufts Cove 1 remains within specifications of the contract with the

OEM. NSPI noted that the parties remain in discussions about how to resolve the issue; [redacted] NSPI also estimated that the outage of Tufts Cove 1's impact on FAM customers due to suboptimal commitment and dispatch is about $200,000. This process is ongoing; [redacted]

In the case of both Lingan 4 and Tufts Cove 1, the AFs for both units in the following year—2017—increased and beat the industry average (notwithstanding ongoing concerns about the status of Tufts Cove 1). This is an important, positive result, as it helps demonstrate the importance of regular planned outages and their expected, positive impact on subsequent availability. We note, too, that in 2015, the only NSPI unit that had an AF below 75% was Lingan 3, which registered a 74% availability for that year;[41] Figure IX-10 above shows that Lingan 3 had extremely high AFs for both 2016 and 2017, further illustrating the expected and positive impact of regular planned outages.

In 2017, Lingan 2 (73.4%) and Tufts Cove 3 (66.5%) saw low AFs. Tufts Cove 3 was largely driven by a more than three-month planned outage for major maintenance, while Lingan 2's AF was driven by forced outages (which we address in a later subsection on DAFOR).

IX.B.4.a.ii. Outage, De-Rating Review

In this section, we provide a review of all outage and de-rating data during the Audit Period. Figure IX-11 contains a summary of all outages by hour across all units in the Audit Period; Figure IX-12 provides the instances of outages by category across all units in the Audit Period.

[41] Liberty 2014-2015 Audit Report, page VIII-5.

Figure IX-11. Outage Hours of NSPI Thermal Generating Units (by Outage Category)

Thermal Plant	Planned	Maintenance	Forced	Total
Tufts Cove 1	2,742.7	1,523.0	1,933.9	6,199.5
Lingan 4	2,792.4	0.0	1,024.2	3,816.6
Tufts Cove 3	3,491.5	137.7	28.5	3,657.7
Tufts Cove 5	1,617.4	124.5	1,441.5	3,183.4
Tufts Cove 2	1,689.1	953.1	459.6	3,101.8
Trenton 5	1,514.1	907.3	511.1	2,932.5
Trenton 6	2,183.1	153.9	317.9	2,654.9
Lingan 2	0.0	2,354.5	52.9	2,407.4
Port Hawkesbury	1,865.0	183.1	175.9	2,224.0
Point Aconi	1,545.3	165.2	412.7	2,123.3
Tufts Cove 6	1,522.6	138.4	228.4	1,889.5
Point Tupper	1,190.0	396.6	133.2	1,719.8
Tufts Cove 4	1,209.9	163.8	176.1	1,549.9
Lingan 1	1,275.6	0.0	135.5	1,411.1
Lingan 3	0.0	87.6	327.5	415.1
Total	**24,638.8**	**7,288.7**	**7,359.0**	**39,286.5**

Figure IX-12. Outage Incidents of NSPI Thermal Generating Units (by Outage Category)

Thermal Plant	Planned	Maintenance	Forced	Total
Tufts Cove 4	12	20	32	64
Tufts Cove 5	10	19	20	49
Port Hawkesbury	4	6	23	33
Trenton 6	5	3	19	27
Trenton 5	3	5	15	23
Tufts Cove 1	6	8	5	19
Tufts Cove 6	6	7	6	19
Lingan 3	0	3	15	18
Point Tupper	3	9	6	18
Lingan 4	3	0	11	14
Tufts Cove 2	4	6	3	13
Lingan 2	0	4	6	10
Point Aconi	3	2	5	10
Lingan 1	2	0	7	9
Tufts Cove 3	4	2	2	8
Total	**65**	**94**	**175**	**334**

Taking planned outages first, one item worth noting regarding planned outages is the percentage of planned outages that were completed within one week of the original schedule. Since 2010, NSPI has completed planned outages within one week of the original schedule between 53% and 76% of the time.[42]

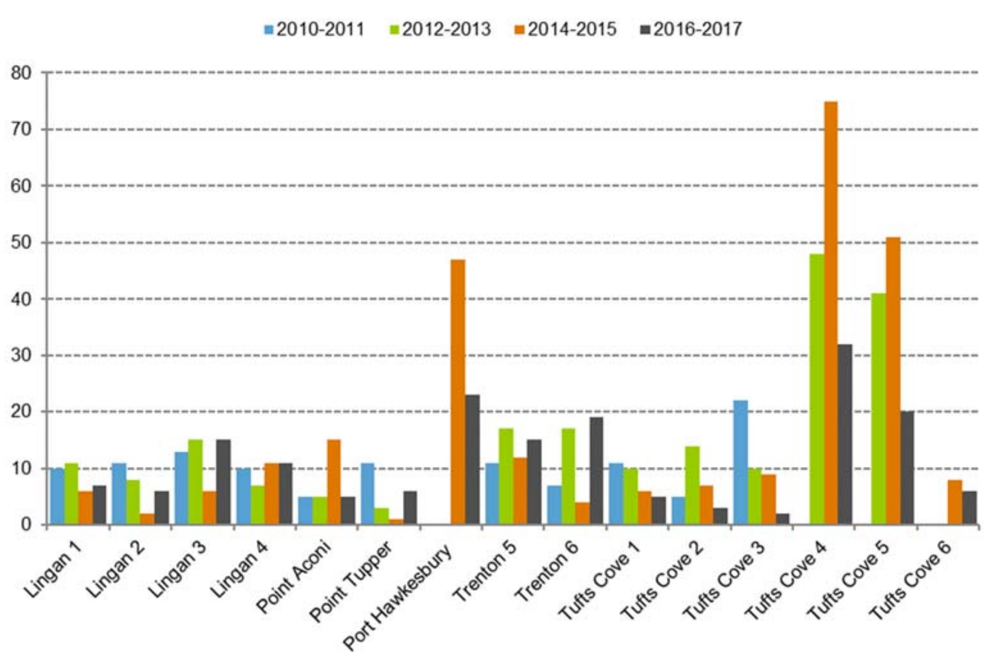
[42] See Liberty 2014-2015 Audit Report, page VIII-11.

In this Audit Period, about 62% of NSPI's planned outages were completed within one week of the original schedule.

Another item worth noting is that NSPI did not schedule any planned outages for the winter peaking months. The latest planned outages—and there were only a few—stretched into early December or began near the end of March. This is sound outage planning strategy, as it (1) avoids shutting down resources during the peak months of the year and (2) allows for extension of planned outages, when necessary and when economic to do so, as outages taken during lower-cost shoulder months reduce the opportunity cost of taking resources offline for planned maintenance.

Regarding forced outages, overall results were positive. For the two-year Audit Period, the total number of forced outages—175—was down 32.7% from the 2014–2015 audit period.[43] Forced outage hours were also down: in this Audit Period, the total number of forced outage hours was 7,359, which was 10.3% lower than the forced outage hours in 2014–2015.[44] On a per unit basis, results were also positive. Most of NSPI's units saw fewer forced outages and fewer forced outage hours in this Audit Period compared with 2014–2015. These points are shown in Figure IX-13 and Figure IX-14, respectively, which also include data from the 2010–2011 and 2012–2013 audit periods.

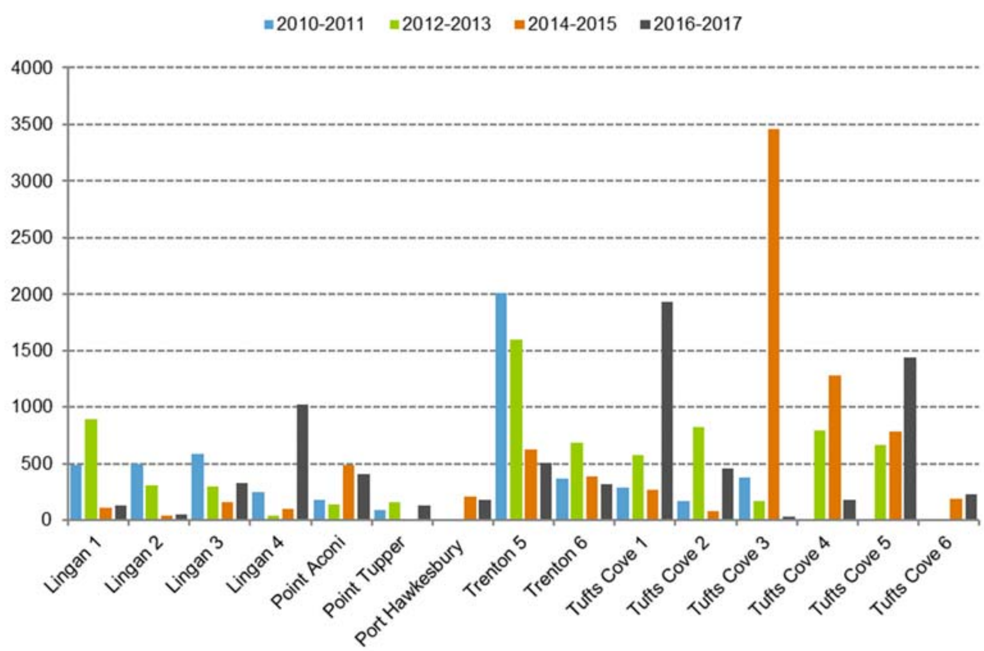
Figure IX-13. Forced Outage Incidents, by Unit, since 2010



[43] See Liberty 2014-2015 Audit Report, page VIII-6.

[44] See Liberty 2014-2015 Audit Report, page VIII-6.

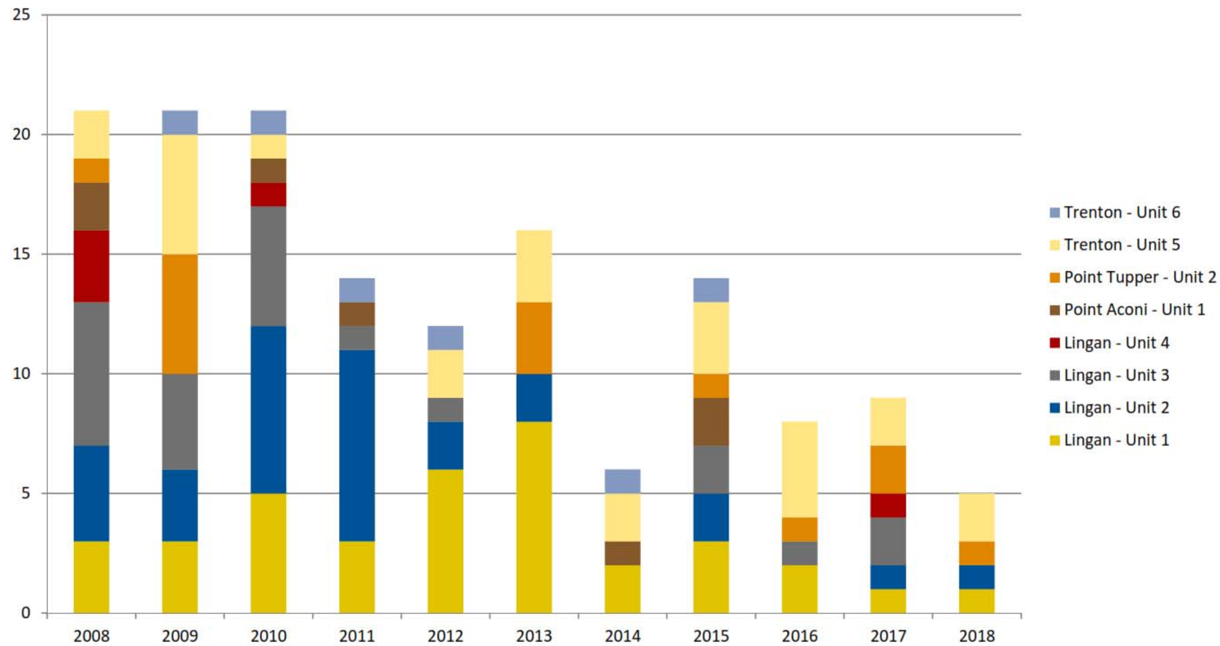
Figure IX-14. Forced Outage Hours, by Unit, since 2010



One driver for the reduced forced outages appears to be NSPI's asset management group's "Reliability Team," which, among many roles, seeks to develop a standardized maintenance strategy and identify risk profiles for individual pieces of generator equipment. The risk profile considers the relative importance of that piece of equipment to the reliable operation of the generating unit, as well as its current condition. Equipment that is critical and in poorer condition is prioritized and can help reduce forced outages. One example of this is the reliability of boiler tubes at NSPI's solid fuel-fired generating units. The past auditor focused on this issue in previous reports.[45] Over time, NSPI has reduced the number of outages due to boiler tube failures—which can be seen below in Figure IX-15—a fact that NSPI believes is attributable in part to its reliability efforts led by its asset management approach.

45 See Liberty 2014-2015 Audit Report, page VIII-7.

Figure IX-15. Total Boiler Tube Failures since 2008 (Solid Fuel-Fired Generating Units)



NSPI also conducts root cause analyses on forced outages, including assessing any equipment-related issues that could apply to other units. Once complete, results of the root cause analysis are communicated so that other units can benefit from those results.

In addition to outages, we also looked at incidents where NSPI thermal units were de-rated during the Audit Period, i.e., when conditions at the plant limited the total potential output of the unit to be something less than the unit's full capacity. In total, NSPI's thermal fleet saw 275 de-rates during the Audit Period. The average de-rate was approximately 22 MW and lasted 56 hours.

NSPI has in place a standardized outage management process with many positive aspects. It is multi-year and looks at the entire NSPI asset portfolio—each generating unit has its own multi-year plan; it includes documented protocols for outage planning, reporting, and execution; and it is centrally controlled by an outage coordinator in the asset management group. Outage reports—which include lessons learned—are prepared and provided to management. NSPI uses a standardized outage planning and execution "dashboard" to plan and track outages and the related reasons for those outages. For example, the dashboard shows the status of the outage scoping, contracts, materials, and execution, ("on track," "completed,"), any internal comments on the outage, and, most importantly, it assigns an individual NSPI employee with ownership of that outage. We also observed evidence that NSPI considers economics in its outage planning.[46] We found NSPI's outage management process to be reasonable.

46 See, e.g., NSPI System Operating Procedure "Generator Outage Scheduling Procedure," Revision No. 6.

Aggregating de-rate and forced outage data is best done and judged using standard metrics. In this case, DAFOR serves this purpose; we address DAFOR in the next subsection.

IX.B.4.a.iii. DAFOR

The second performance metric we examine is the DAFOR. DAFOR represents the percentage probability that a unit will be in forced outage. DAFOR includes both forced outage hours as well as adjusted de-rated hours; it does not include planned outage hours or hours in which the unit is shut down for economic reasons. DAFOR is a measure used in Canada; its NERC-equivalent is the Equivalent Forced Outage Rate (EFOR) metric,[47] which we use as a reasonable proxy for comparison purposes. The lower the DAFOR, the less time that unit spent on forced outage or in de-rated status.

Figure IX-16 below shows NSPI's thermal fleet's DAFOR versus industry averages; green highlights denote performance that is better than average by at least five percentage points; red indicates the opposite.

Figure IX-16. NSPI's DAFOR, by Unit, by Year, Compared to GADS EFOR Standard

Thermal Plant	DAFOR (2016)	DAFOR (2017)	GADS EFOR Standard
Lingan 1	1.5%	0.5%	8.2%
Lingan 2	0.3%	1.5%	8.2%
Lingan 3	6.9%	2.6%	8.2%
Lingan 4	5.0%	2.7%	8.2%
Point Aconi	3.2%	1.2%	8.2%
Point Tupper	2.9%	2.2%	8.2%
Port Hawkesbury	0.6%	1.7%	10.8%
Trenton 5	6.4%	1.8%	8.2%
Trenton 6	5.1%	5.2%	8.2%
Tufts Cove 1	75.7%	7.2%	20.5%
Tufts Cove 2	14.4%	6.3%	20.5%
Tufts Cove 3	0.6%	1.4%	13.7%
Tufts Cove 4	5.3%	1.5%	4.7%
Tufts Cove 5	6.3%	8.3%	4.7%
Tufts Cove 6	1.4%	2.2%	4.7%

Tufts Cove 1 is an obvious outlier to otherwise positive results. Tufts Cove 1 was on forced outage for about 1,644 hours during 2016, or about 69 days. That data was driven almost entirely by a forced outage that began in late October and lasted through the end of the year—we provide the details of this issue above in our discussion of Availability Factor.

[47] NERC, "Appendix F – Performance Indexes and Equations."

IX.B.4.a.iv. Heat Rate

The third performance metric we considered was Heat Rate, which is a measure of a generating unit's efficiency. It divides fuel burned (in MMBtu)—or energy "in"—by electricity produced (in kWh)—or energy "out."[48] The lower the heat rate, the more efficient the generating unit. Figure IX-17 shows the Heat Rates for each of NSPI's units. Note that NERC does not provide averages in GADS for heat rate.

Figure IX-17. NSPI Thermal Unit Heat Rates (MMBtu/kWh)[49]

Thermal Plant	Heat Rate (2016)	Heat Rate (2017)
Lingan 1	[redacted]	[redacted]
Lingan 2	[redacted]	[redacted]
Lingan 3	[redacted]	[redacted]
Lingan 4	[redacted]	[redacted]
Point Aconi	[redacted]	[redacted]
Point Tupper	[redacted]	[redacted]
Trenton 5	[redacted]	[redacted]
Trenton 6	[redacted]	[redacted]
Tufts Cove 1	[redacted]	[redacted]
Tufts Cove 2	[redacted]	[redacted]
Tufts Cove 3	[redacted]	[redacted]
Tufts Cove 4-6	[redacted]	[redacted]

The US Energy Information Administration posts average heat rates for general fuel sources—i.e., "coal," "natural gas," etc.[50] This is an imperfect proxy but can give some indication of the efficiency of the NSPI fleet. [redacted] This is a positive development, as it becomes more difficult to maintain—let alone improve—a unit's heat rate as it ages, and more so as its capacity factor falls. Both of these conditions are present in NSPI's coal fleet. For natural gas, [redacted] the Tufts Cove units. This result is driven by the small size and vintages of the three steam units; as for the combined-cycle units, those offer [redacted] heat rates, but still [redacted] heat rates available in newer, larger combined-cycle plants.[51]

As part of NSPI's overall fleet performance program, NSPI focuses on heat rates and employs a heat rate improvement program to detect and quantify heat rate deviations, diagnose causes of lagging heat rates, identify corrective actions, schedule and complete maintenance work, and track and confirm heat rate improvements. In this process, NSPI engages in a number of practices and employs numerous

48 NERC, "Understanding Appendix F: The 'Heart' of the NERC GADS DRI," May, August, & October 2017, slide 56, *available at* https://www.nerc.com/pa/RAPA/gads/Training/Understanding_Appendix_F-rev2017-05-01pm.pdf.

49 NSPI 2017 FAM Annual Report, A-6.

50 U.S. EIA, "Table 8.1. Average Operating Heat Rate for Selected Energy Sources, 2006 through 2016," *available at* https://www.eia.gov/electricity/annual/html/epa_08_01.html.

51 See, for example, Panda Temple Power, a 758 MW gas-fired combined cycle power plant in Temple, Texas.

controls to ensure accuracy of measurements and diagnoses—such as daily verification of a unit's generation output and regular calibration of instrumentation—as well as tests of generation equipment and monitoring of combustion efficiency. The Asset Management Group conducts daily performance checks on each of NSPI's thermal generating units, such as steam and condenser exhaust pressure, and conducts a monthly heat rate review process that includes input from FERM, NSPI engineers, and plant superintendents.[52]

The best evidence of the effectiveness of this considerable heat rate improvement program is to compare NSPI's Audit Period heat rates to its historical heat rates.[53] In comparing NSPI's 2017 heat rates to its 2015 heat rates, we note that the majority of NSPI's fleet enjoyed lower heat rates in 2017. Figure IX-18 shows this in more detail, with heat rate improvements of at least 0.5% highlighted in green and heat rate increases of at least 0.5% shown in red.

Figure IX-18. Comparison of 2015, 2017 NSPI Thermal Unit Heat Rates

Thermal Plant	Heat Rate (2015)	Heat Rate (2017)	Percentage Change
Lingan 1	[redacted]		
Lingan 2			
Lingan 3			
Lingan 4			
Point Aconi			
Point Tupper			
Trenton 5			
Trenton 6			
Tufts Cove 1			
Tufts Cove 2			
Tufts Cove 3			
Tufts Cove 4-6			

IX.B.4.a.v. Data Reporting

In reviewing NSPI's outage, de-rate, and other data provided by NSPI during the course of the audit, we discovered several outages and de-rates that appeared not to have been captured by NSPI in its outage and de-rate reporting. Specifically, we found some discrepancies between NSPI's outage and de-rate data—which NSPI provided to us at our request as part of the audit process—and other documentation provided by NSPI in the course of the audit. In probing this further with NSPI, we found that NSPI had adequate and reasonable explanations for all but one of those discrepancies. For example, in outage cases, generating units were unavailable due to transmission outages, which NSPI is not required to report as part of a generating unit's DAFOR or other performance metrics. For instance, on December 19, 2016,

52 Note that our finding in this paragraph is separate from our discussion of NSPI's operation of its plants through economic commitment and dispatch decisions, which has a direct impact on heat rate. We discuss that issue in the Economic Commitment and Dispatch chapter.

53 Other factors – like increased capacity factors – can also contribute to lower heat rates. We discuss the interaction between heat rates and capacity factors in the Economic Commitment and Dispatch chapter.

NSPI's trade logs indicate that "Point Aconi tripped off overnight again" and "LG [Lingan] forced outage." NSPI's records indicate that at hour 20:00 on December 18, 2016, Point Aconi's gross generation was 178 MW; in hour 21:00, gross generation fell to zero and stayed at zero for the next 90 hours, through the 15:00 hour of December 22, 2016. NSPI did not report an outage or de-rate for Point Aconi or any of the Lingan units on December 18, 19, 20, 21, or 22, 2016. NSPI explained that the outage was actually captured in its logs and reported as an external event, but not as a generation outage—rather, as a transmission event outage—and logged accordingly.

In the cases of some of the de-rate discrepancies, NSPI made it clear that the generating units in question were not required to be de-rated because the units were able to run at full output using secondary fuel. For example, on August 2, 2017, NSPI's trading logs stated that "Trenton is limited so we'll need to run harder on the gas for tomorrow." NSPI did not report a de-rate for Trenton 5 or 6 on August 3, 2017.[54] NSPI explained that Trenton could run at full output using HFO, so a de-rate was not required.

Aside from these reasonable explanations and clarifications, we did note one outage that was not fully explained. On September 13, 2017, NSPI's trading logs indicate that "LG4 was recalled but had a tube leak and didn't come back." The following day, the trade logs indicate "No lingain 4"[sic]. Indeed, Lingan 4's generation during September 13, 14, and 15 of 2017 was effectively zero in all hours. NSPI did not report either a de-rate or an outage for Lingan 4 on any of these days. NSPI advised that:

> Lingan Unit 4 was coded as Available but not Operating from July 6th to July 16th due to economics. During this time [the] unit was on a 24 hour return to service requirement. The unit was dispatched on the morning of July 12th for morning on July 13th. The unit experienced a delay in the startup from a boiler tube failure but was able to complete the repair in the 24 hour window. Since the expected sync time was delayed the unit was not committed and was not needed for economic dispatch. In hindsight this could have been coded as a starting failure outage for 3.5 hours. This would have an impact of a 0.04 percent increase to the unit's DAFOR metric which was 2.7 [percent] in 2017.

Discrepancies in outage and de-rate data can undermine confidence in the reliability of the outage and de-rate data directly reported by NSPI. The reliability of the outage and de-rate data is significant to the determination of system capacity reserves, near-term and long-term resource planning, plant retirement decisions, and so forth. We reiterate here that we only found one instance of a discrepancy in the outage data; however, we note that the available information did not allow for a comprehensive assessment of data reliability. That is, the trading logs in which we discovered the discrepancy are not intended to capture all outage and de-rate information, so what information is available from that source is necessarily incomplete. While we find that NSPI's explanation of the apparent data discrepancies is reasonable and that there is no evidence of systematic problems in the utility's reporting of outage and de-rate data

54 Output data suggest Trenton 6 was operating at or near maximum loading during August 3, while Trenton 5 was not. It is difficult to use this data to determine if Trenton 5 was truly de-rated, since the unit could have been dispatched at a lower loading level for economic reasons.

subject to NERC requirements, we also find that plant performance data would be more complete for the Board's purposes if they included information on the extent of generating unit limitations, such as environmental limitations (e.g., opacity) and the inability of the unit to produce at full load with its primary fuel (such as in the August 2017 Trenton example above). We recommend that in reporting plant performance to the Board, NSPI should include information on the incidence of plant limitations (e.g., inability to produce at full load with primary fuel, or limitations associated with opacity).

IX.B.5. **OM&G Costs**

NSPI spent about [redacted] in OM&G expenses per year during the Audit Period. These expenditures are largely in line with previous years' OM&G expenses, as is shown in Figure IX-19 below.

Figure IX-19. OM&G Costs (2013–2017, $mm)[55]

Plant	2013	2014	2015	2016	2017
Lingan	[redacted]				
Tufts Cove					
Pt. Tupper					
Pt. Aconi					
Trenton					
Hydro					
Wind					
Combustion Turbines					
Plant Operations					
Biomass					
Common Capital Spending					
Total	**$115.5**	**$107.2**	**$109.3**	**$106.0**	**$104.9**

Given the different sizes and number of units at each generating plant, it is instructive to provide OM&G costs on a per megawatt basis across each NSPI plant. As is shown in Figure IX-20, the NSPI fleet averages about [redacted] in average annual OM&G costs; the PHP biomass plant [redacted] and NSPI's wind generation [redacted] were the most expensive units, while the combustion turbines [redacted] and the hydro units [redacted] were the least expensive.

55 Common OM&G items include FERM and Plant Operations expenses. 2017 FAM Annual Report, A-7.

Figure IX-20. Average Annual OM&G Costs During Audit Period ($/MW)[56]

Plant	Audit Period Annual Average ($mm)	Capacity (MW)	OM&G Costs per MW
Biomass	[redacted]		
Wind			
Pt. Tupper			
Pt. Aconi			
Trenton			
Tufts Cove			
Lingan			
Hydro			
Combustion Turbines			
Total			

Another way to look at OM&G costs is on a $/MWh basis. As is shown in Figure IX-21, NSPI's OM&G costs across all its generators averaged $9.49/MWh during the Audit Period. Leaving aside the renewable generators and the peaking combustion turbines, the fleetwide thermal average was [redacted] for the Audit Period, which is lower than the comparable averages in the previous two audit periods.[57]

Figure IX-21. Average Annual OM&G Costs During Audit Period ($/MWh)[58]

Plant	OM&G Costs ($mm)	MWh	OM&G Costs per MWh
Combustion Turbines	[redacted]		
Biomass			
Wind			
Hydro			
Tufts Cove			
Pt. Tupper			
Trenton			
Pt. Aconi			
Lingan			
Total			

Though OM&G costs are largely not recovered through the FAM, they are important to show here, as these costs should be part of NSPI's IRP process going forward—in assessing the costs and benefits of individual resources and their modeled asset lives and retirement dates, these are important costs to consider. Moreover, some OM&G costs are recovered through the FAM, albeit a small percentage—about 3.5%. Specifically, just [redacted] and [redacted] of OM&G costs were recovered through the

56 Figure IX-20 does not consider common OM&G items. 2017 FAM Annual Report, A-7.

57 See Liberty 2014-2015 Audit Report, page VIII-18.

58 2017 Annual FAM Report, A-2, A-7; 2016 Annual FAM Report, A-2.

FAM in 2016 and 2017, respectively; in all cases, these FAM-recoverable costs relate to certain fuel handling costs.[59]

We considered the FAM-recoverable OM&G costs in three ways. First, as the past auditor has done, we reviewed the categories of FAM-recoverable OM&G costs to determine what expenses are included in these amounts. Second, we reviewed NSPI's actual expenditures versus its forecasts. Third, we reviewed these expenses for any outliers that demand attention.

Figure IX-22 shows the amounts and percentages of FAM-recoverable OM&G expenses across four categories: labor, materials, contracts, and other. Labor accounted for almost 51% of FAM-recoverable OM&G costs, with contracts accounting for about 34% of the total. This Audit Period saw a shift in reliance to contracts instead of internal labor resources; for example, in the previous two audit periods, internal labor accounted for 62% and 67% of total FAM-recoverable OM&G costs, with contracts accounting for about 20% and 15%, respectively.

Figure IX-22. FAM-Recoverable OM&G Cost, by Category

OM&G Category	Cost	Percentage
Labor	[redacted]	
Contracts		
Other		
Materials		
Total		

In reviewing the FAM-recoverable OM&G costs in detail, including the budgeted amounts for OM&G costs in the Audit Period, we noted the trend identified by the previous auditor—i.e., that NSPI appears to regularly overestimate its "regular labor," which is the scheduled hours of its internal employees, and underestimate the amount of overtime, term, and contract labor needed to make up the difference. In particular, for this Audit Period, NSPI's regular labor hours were 15% and 12% below budget in 2016 and 2017, respectively, while overtime labor was 17% and 47% above budget in those respective years. Unlike previous years, however, term labor and contracted labor varied significantly between the two years and did not necessarily follow this trend.

Figure IX-23. FAM-Recoverable Labor Cost Deviations from Budget, by Category (2010–2017)[60]

Labor Category	2010	2011	2012	2013	2014	2015	2016	2017
Regular Labor	–13%	–10%	–13%	–12%	2%	–11%	–15%	–12%
Overtime Labor	43%	39%	41%	53%	51%	50%	17%	47%
Term Labor	69%	52%	61%	81%	141%	79%	–39%	125%
Contracts	41%	49%	4%	15%	7%	-20%	–36%	1%

59 See section 3.2.2 of the FAM POA.

60 Figure IX-23 includes costs applicable to Point Aconi, Lingan, and Trenton only.

Another way to consider overtime labor is as a percentage of overall labor costs here. In this case, NSPI's overtime labor accounted for 13.8% of all labor costs in 2016 and 13.5% in 2017. These figures represent an improvement from previous audit periods, where those percentages have been between 14% and 18%.[61] Overall, despite the improvement, given that NSPI has reduced its internal employees at its thermal plants in recent years,[62] this still may suggest an increased reliance on overtime labor when there are unexpected issues arise at thermal plants that require additional work. NSPI reasonably explained that it plans its regular labor based on full availability of its existing labor force—that is, there are no allowances made for parental leave, disability, resignations, or other labor disruptions that were not known at the time of the budgeting process, which would require NSPI to make up for this lost labor with other options, such as overtime, term, or contract labor. We find this approach to be reasonable, as it is a logical approach to planning that removes discretion in estimating the likelihood of labor resource disruptions or events; still, this is a trend to watch going forward.

IX.B.6. Capital Investment

With one exception, no capital investments related to NSPI's power plants are recovered through the FAM. We address that exception—the $1,023,342 item filed with the Board as Capital Item 47331-LM6000 191-253 Engine Refurbishment U&U (Docket M08144)—in our final chapter. Despite the remainder of the capital investments being recovered through depreciation expense, and not through the FAM, we include a brief overview of these costs, since they are intended to keep the NSPI fleet in sufficient operating condition and are thus part of the sustaining capital associated with NSPI's generation fleet. Again, going forward, through the IRP process, we would recommend that these costs, too, are included in reviewing NSPI's existing generating assets in the context of optimal resource allocation and decision-making. As we have noted above, today's IRP planning process directly impacts future FAM audits.

Figure IX-24 shows that across NSPI's generating fleet, including investment that accrues across the portfolio, NSPI invested $115 million in 2016 and $125.1 million in 2017. This is generally consistent with previous years, though down from the previous audit period.

[61] See 2014-2015 Liberty FAM Audit Report, page VIII-20.

[62] See 2014-2015 Liberty FAM Audit Report, page VIII-19.

Figure IX-24. Capital Investment by Plant (2013–2017, $mm)[63]

Plant	2013	2014	2015	2016	2017
Lingan	$6.2	$8.0	$29.3	$26.0	$12.2
Tufts Cove	$11.0	$9.6	$6.0	$11.7	$14.9
Pt. Tupper	$5.2	$3.2	$9.1	$4.6	$6.9
Pt. Aconi	$4.6	$11.7	$9.5	$11.8	$17.0
Trenton	$2.0	$6.7	$18.1	$18.1	$24.8
Hydro	$25.1	$18.7	$28.6	$34.9	$29.8
Combustion Turbines	$8.8	$7.6	$10.6	$6.7	$17.9
Biomass	-	$1.6	$1.2	$1.1	$1.1
Wind	-	$82.9	$17.0	$0.1	$0.5
Common Capital Spending	$6.4	$0.3	$1.4	$0.9	$4.3
Total	$69.3	$150.3	$130.8	$115.9	$129.4

Figure IX-25 shows this same capital investment, by plant, but broken down in dollars per MW. Over the Audit Period, Point Aconi, the hydro units, and Trenton stood out as the units that saw the greatest investment per MW, while the wind units, PHP, and Lingan saw the least. These results can vary considerably over time, as a unit can receive significant investment in a given year for a major maintenance overhaul, while in subsequent years, they may see far less investment.

Figure IX-25. Average Annual Capital Investment by Plant ($/MW)[64]

Plant	Audit Period Annual Average ($mm)	Capacity (MW)	Capital Investment per MW
Pt. Aconi	$14.4	168	$85,714.3
Hydro	$32.4	399	$81,077.7
Trenton	$21.5	304	$70,559.2
Tufts Cove 1-3	$13.3	318	$41,823.9
Pt. Tupper	$5.8	150	$38,333.3
Combustion Turbines (incl. TC 4-6)	$12.3	375	$32,800.0
Lingan	$19.1	612	$31,209.2
Biomass	$1.1	43	$25,581.4
Wind	$0.3	81	$3,703.7
Total	$120.1	2,450	$49,000.0

IX.B.7. Power Plant Visits

The FAM POA requires the fuel auditor to "[c]onduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring."[65] We conducted site visits at a total of four power plants: Tufts Cove, Trenton, PHP biomass, and Lingan. Our site visits focused on the items identified in the FAM POA; we did not conduct in-depth examinations of the status of the generating

63 Common Capital Spending refers to FERM capital investments. Tufts Cove refers to units 1, 2, and 3; Combustion Turbines includes Tufts Cove units 4, 5, and 6. See 2017 FAM Annual Report, A-7.

64 Figure IX-25 does not include Common Capital Spending. Source: 2017 FAM Annual Report, A-7.

65 FAM POA section 5.0.

assets themselves, as this was outside the scope of our audit and would not be able to be accomplished in a one-day site visit. During our site visits, we met with plant management and personnel and toured the facilities, including the control room, fuel testing labs, and the solid-fuel inventory locations.

Our on-site inspections identified no concerns with fuel handling, quality control, inventory management, or performance monitoring. We assessed (1) how NSPI received fuel, looking for industry-standard methods of receiving shipments. We looked at (2) how NSPI ensured that the quantity of fuel met what it purchased, including (for solid fuel) where the solid fuel was weighed. We considered (3) how fuel was tested for quality (e.g., ash content), including at on-site plant labs themselves. At solid fuel-fired plants, we toured (4) solid fuel piles/inventory to see how NSPI stored and managed its solid fuel supply, looking for industry-standard approaches to supply management (i.e., avoiding the need to move coal more often than necessary, using reasonable methods for separating and tracking solid fuels of different types at the same plant (i.e., low- and mid-sulphur coals), and using industry-standard methods for blending solid fuels). We also (5) toured and reviewed plant control rooms to see, in real time, the performance of each generating unit across a variety of metrics, including real-time output, fuel burn, and emissions. In all cases, we found no instances of unreasonable practices.

We also note that on all of our site visits, we found NSPI personnel to be welcoming and forthcoming in answering all our questions. Plant management and personnel were knowledgeable and experienced. We noted a similarity in the presentations of plant-specific data and performance among the plants, a testament to NSPI's focus on integrating the management of its asset fleet. While not necessarily part of our audit scope, we noted NSPI's plant personnel's focus on safety and on continuous improvement as part of the overall culture.

IX.B.8. Trenton

One plant we wanted to highlight was Trenton, for the purposes of illustrating the importance—and complexity—of the resource decisions faced by NSPI and the importance of our recommendation regarding more regular, robust IRP planning. Perhaps no NSPI plant offers a better example of this complexity of the resource decisions facing NSPI, the Board, and stakeholders than Trenton. As we note elsewhere, part of the "robustness" of NSPI's IRP planning will be driven in part by a complete accounting of the costs and benefits associated with each of NSPI's existing assets, plus a complete accounting of the costs and benefits of the full range of NSPI's potential future alternative investments—which we detail below and elsewhere. In assessing NSPI's existing assets, consider the complexity of Trenton, which:

- Is the only generating station that relies on rail shipments of coal from the Point Tupper Marine Terminal, which is an NSPI-owned asset essentially co-located next to the Point Tupper coal-fired facility. Without Trenton, the used and usefulness of the Point Tupper Marine Terminal would rightly be called into question.

- Has seen significant costs for the removal of asbestos. NSPI explained that Trenton has a 10-year plan to remove all asbestos from its active units. (We judged this approach to be positive in that NSPI aims to remove asbestos during maintenance outages when that asbestos can be reached and removed, while also maintaining the ability to address asbestos-removal needs as they arise.) Moreover, two other, long-retired units at Trenton (units 3 and 4) remain at the facility, and each will need asbestos removal when the plant is eventually retired.
- Trenton 5, while the oldest thermal unit in the fleet, has a relatively new (2009) generator and saw an uptick in capacity factor in the Audit Period. However, NSPI projects a capacity factor of just 14% in 2018.[66] Moreover, Trenton 5 also lacks some of the redundancies of more modern coal-fired plants that makes it less reliable. (We note, though, that NSPI has taken remedial steps to address this concern, such as having parts on hand at the facility to quickly replace the faulty piece of equipment during an outage.)
- Trenton 6, while much newer and with a higher forecasted capacity factor in 2018 (79%),[67] was designed to burn the unique high ash-content coal mined at [redacted] As explained thoroughly in the Solid Fuel Procurement and Solid Fuel Supply Management chapters, [redacted] This will leave Trenton 6 fully reliant on imported coal, which adds strain on the Point Tupper Marine Terminal coal circuit—which could lead to additional expansion investment to accommodate this additional throughput.
- Like many of NSPI's thermal generating assets, Trenton still has a significant net book value. As of 2016, its net book value was $270.8 million; NSPI continues to earn a return on and of this capital investment over time.

Developing a plan to address these facts and uncertainties in concert with the full range of alternatives available to NSPI—from DSM, transmission investments, firm natural gas investments, and so on—is not a simple process, but it is one that will pay dividends to NSPI and its ratepayers the sooner NSPI implements a regular and robust IRP process.

IX.B.9. Liberty's 2014–2015 Recommendations

The previous fuel auditor offered three recommendations related to this topic. First, Liberty recommended that NSPI "[a]nalyze the deteriorating performance of TC 1-3, at least as reflected in DAFOR, and determine if corrective action is appropriate."[68] NSPI disagreed with this recommendation "and the underlying conclusions."[69] NSPI stated, "As agreed to as part of the FAM Audit Settlement Agreement, this item was addressed through a technical conference for the FAM Small Working Group held on April 13, 2017 regarding [NSPI's] future plan for its thermal generation resources and the

66 NSPI 2017 FAM Annual Report, A-10.
67 NSPI 2017 FAM Annual Report, A-10.
68 Liberty 2014-2015 Audit Report, page VIII-29.
69 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 16.

performance of the Tufts Cove Units."[70] Besides this response, we would note that DAFOR for Tufts Cove units 1, 2, and 3 were all lower than GADS averages in both years—see Figure IX-18 above—with one exception. That exception was Tufts Cove 1 in 2016, which is the subject of ongoing deliberations with the OEM, as it is NSPI's position that the OEM is responsible for the extended forced outage of Tufts Cove 1 in 2016. We further note that our recommendation below to conduct regular and robust IRP planning will require NSPI to regularly assess the economics of all of its units—including the Tufts Cove gas-fired steam turbines. We therefore find that NSPI has appropriately addressed this recommendation, and we note that our IRP recommendation below ensures that NSPI will continue to assess the economics of Tufts Cove 1, 2, and 3 going forward.

Liberty's second recommendation was that NSPI "[s]eek a more realistic future plan for [NSPI's] thermal generation resources, including the identification of resulting issues, such as the handling of potential stranded costs."[71] NSPI disagreed with the recommendation "and the underlying conclusions."[72] NSPI stated:

> As agreed to as part of the FAM Audit Settlement Agreement, this item was addressed through a technical conference for the FAM Small Working Group held on April 13, 2017 regarding [NSPI's] future plan for its thermal generation resources and the performance of the Tufts Cove Units. The Board has initiated a separate proceeding and has engaged Synapse Energy Economics Inc. (Synapse) to undertake an independent analysis of optimal utilization of generation resources and potential options that may be more economical for Nova Scotia ratepayers. [NSPI] understands that performance and utilization of [NSPI's] thermal fleet is to be evaluated as part of that work, and that this action item is therefore included within the scope of that process.[73]

We find NSPI's response to this recommendation reasonable, noting that the Synapse work was completed. We also note that our IRP recommendation below will require NSPI to conduct the sort of analyses suggested by the previous fuel auditor on a regular basis.

Liberty's third recommendation was that NSPI "[s]eek to define reasonable expectations for the expected performance of the Tufts Cove combined cycle plant, with the intention that unjustified performance shortfalls will result in financial consequences."[74] NSPI disagreed with the recommendation "and the underlying conclusions," noting that this item "was addressed in the Reply Evidence and at the technical conference for the FAM Small Working Group held on April 13, 2017 regarding [NSPI's] future plan for its thermal generation resources and the performance of the Tufts Cove Units."[75] We find

70 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 16.
71 Liberty 2014-2015 Audit Report, page VIII-29.
72 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 16.
73 NSPI 2016 FAM Audit Action Plan, July 31, 2017, pages 16 to 17.
74 Liberty 2014-2015 Audit Report, page VII-29.
75 NSPI 2016 FAM Audit Action Plan, July 31, 2017, page 16.

NSPI's response to this recommendation reasonable, given the general improvements seen in the performance of Tufts Cove units 4–6 and their performance during the Audit Period relative to GADS averages. Regarding the costs of the Tufts Cove 4 unit's oil manifold replacement and associated engineering studies, we address that issue in our final chapter. We also note that our IRP recommendation below includes a robust review of NSPI's existing assets, including the Tufts Cove units.

IX.C. Conclusions

Conclusion IX-1: NSPI's resource portfolio has some of the highest degree of wind penetration in North America.

Conclusion IX-2: NSPI's portfolio is not optimal for providing the necessary operational characteristics to balance the high degree of wind on its system.

Conclusion IX-3: The impact of the high wind penetration has been that NSPI's thermal units have been displaced as high-capacity factor, baseload resources and have instead forced these units to become low-capacity factor, cycling units, which is not their intended design. In the short run, this leads to lower-capacity factors and loading levels. In the longer run, this can lead to increased degradation of these units over time.

Conclusion IX-4: Given NSPI's peak load forecast and planning reserve margin of 20%, NSPI's generating fleet is not significantly over-capacity. While the wind resources have displaced much of the needed *energy* from NSPI's thermal resources, these resources remain needed for *capacity*, at least as is consistent with NSPI's most recent peak load forecast and planning reserve margin, the two variables that matter most when considering the appropriate amount of capacity installed in Nova Scotia.

Conclusion IX-5: The importance, therefore, of (1) peak load actuals and forecasts and (2) the planning reserve margin cannot be overstated and thus should be vetted rigorously in NSPI's future planning processes. This is especially true since NSPI only considers whether its current 20% planning reserve margin—among the highest in North America—is optimal during formal IRP planning, which it essentially conducts only when required by the Board.

Conclusion IX-6: NSPI's wind penetration places a premium on accurate examination of the capacity value of wind generation. While indicative and not intended to replace NSPI's industry-standard reliance on effective load carrying capability studies, our highly simplified analysis above showed that, during the Audit Period, wind generation produced at a 53% average capacity factor during the 52 highest peak hours. NSPI should regularly assess the appropriateness of its wind capacity value assumptions to ensure its customers are benefitting appropriately from the substantial wind on its system.

Conclusion IX-7: NSPI's generating fleet requires substantial OM&G expenses and capital investment to keep it operational. During the Audit Period, these expenses and investments were largely in line with previous years.

Conclusion IX-8: NSPI would benefit from regular, robust IRP planning and reporting that (1) prevents overestimation of peak load, (2) considers the optimal planning reserve margin, (3) conducts a complete accounting of the costs and benefits of each of NSPI's existing generating assets (including the capacity value of existing wind), and (4) conducts a complete accounting of the costs and benefits of all alternatives open to NSPI, including demand-side management and resources, transmission investments (including New Brunswick-Nova Scotia or other intertie expansion), and firm natural gas options. (Recommendation)

Conclusion IX-9: NSPI's thermal generating fleet generally outperformed industry averages in Availability Factor and DAFOR. Capacity factors were well below NSPI's pre-2008 capacity factors, but were not inconsistent with thermal units being operated as NSPI is currently operating its units in response to higher wind penetration.

Conclusion IX-10: NSPI showed improvements in both the number and duration of forced outages over the previous Audit Period.

Conclusion IX-11: NSPI's heat rates also showed modest improvements over the previous Audit Period.

Conclusion IX-12: NSPI has codified a consideration of economics in determining the optimal length to keep a unit on planned outage. NSPI has provided clear evidence of this in practice in some cases, such as avoiding any planned outages during the winter months.

Conclusion IX-13: NSPI's asset management approach is robust, appropriately uses root cause analysis in addressing outages, and provides solid structure and standardization in tracking, assessing, and seeking to improve generator performance.

Conclusion IX-14: NSPI continues to rely upon a considerable amount of overtime labor as a percentage of its FAM-recoverable labor costs.

Conclusion IX-15: We found one discrepancy between NSPI's outage data—which NSPI provided to us at our request as part of the audit process—and other NSPI documentation in the course of the audit. That discrepancy had a *de minimis* effect on performance metrics, but can (if persistent) undermine confidence in the reliability of the outage and de-rate data directly reported by NSPI. (Recommendation)

Conclusion IX-16: Tufts Cove 1 suffered from a substantial outage during 2016 (stretching into 2017) that greatly reduced its performance. NSPI identified the cause as [redacted] with whom NSPI is currently in negotiations regarding a settlement. Besides maintenance costs of about [redacted] the outages of Tufts Cove 1 [redacted] have had an estimated impact of [redacted] on FAM customers. (Recommendation)

Conclusion IX-17: The Trenton plant faces unique uncertainties going forward, including asbestos removal needs, fuel supply concerns for Trenton 6, and a very low projected capacity factor for Trenton 5 in 2018.

IX.D. Recommendations

Recommendation IX-1: NSPI should conduct regular and robust IRP planning to help ensure that its resource fleet meets NERC and NPCC requirements without being over-capacity. That IRP planning should:

- Be conducted regularly (e.g., every two years).
- Determine the *optimal* planning reserve margin, not just reconsider whether a 20% planning reserve margin adequately meets NPCC or NERC standards. This will ensure that NSPI will be regularly determining the lowest planning reserve margin possible to meet NPCC requirements, rather than just assessing if "20%" remains in compliance.
- Provide a transparent forecast of peak load that can be fully vetted by the Board, the Board's consultants, and stakeholders, as applicable.
- Consider the full costs and benefits of all investment alternatives, including firm import capacity; transmission expansion; demand-side management; additional domestic and external hydro resources, including pumped hydro storage and additional hydro delivered over the Maritime Link; natural gas infrastructure investments; and emerging technologies as alternatives to traditional maintenance of existing generation or expansion of NSPI's portfolio.
- Regarding natural gas infrastructure investments (e.g., natural gas-fired combined cycle generation, firm pipeline capacity), include use the variable cost of gas (commodity, fuel, and variable pipeline charges) as the input into PLEXOS model runs, and not include the capital costs of the investment in commitment and dispatch costs, but instead add the fixed costs to the cost of generation subsequent to the PLEXOS runs. NSPI should also evaluate potential changes to its generation fleet by including updated, combined-cycle technology as a generation option.
- Explicitly address the effect of PHP load. The LRT requires that NSPI exclude PHP from its planning considerations. NSPI should assess the effect of incorporating PHP load in resource planning to ensure that PHP load does not impose net costs on FAM customers over a longer time horizon.
- Consider the full costs and benefits of maintaining all of NSPI's existing generating assets. This would include the environmental costs/benefits, the sustaining capital costs, OM&G projections, capital expenditures to address fuel transportation and handling infrastructure, decommissioning costs, NSPI's return of and on capital related to each plant, and FAM cost impacts, among potentially many others.
- Determine a reasonable effective load carrying capability for both existing and new wind resources.
- Allow for Board and stakeholder review and input. IRPs are only as useful as the assumptions that drive them, so it is important that NSPI's IRP methodology and assumptions be vetted by third parties and experts.

Recommendation IX-2: In negotiating a settlement with [redacted] NSPI should seek to (1) [redacted] and (2) [redacted]

Recommendation IX-3: In reporting plant performance to the Board, NSPI should include information on the incidence of plant limitations (e.g., inability to produce at full load with primary fuel, or limitations associated with opacity).

X. Economic Commitment and Dispatch

X.A. Background

X.A.1. Least Cost Dispatch

Unit commitment and dispatch is a daily process to determine which generating units to operate and the level at which to operate them to satisfy electrical load needs. The goal is to find the set of generators that can produce the needed energy at the lowest possible cost while maintaining the reliability of the system. Unit commitment and dispatch is the last step in a long process that starts with planning and building the electrical system, then scheduling annual generation and transmission maintenance outages, then planning for weather and expected load weeks to months ahead, and finally executing the operation of the system as it is configured on the day of operation.

NSPI's unit commitment and dispatch process starts each morning the day prior to the day of operation and continues up to real-time operation. The units that will operate the next day are chosen from the set of available units. As the day progresses and more accurate information about weather and load is obtained, the unit schedule may change. After units are committed, uncertainties are managed by changing the operating levels on the units themselves. In real time, generation units are ramped up and down with changes in load to keep energy production equal to energy consumption at all times.

To determine which units to operate, generation units are stacked in merit order, from lowest to highest cost. Starting at the bottom of the stack, units are chosen sequentially until all energy needs are met. At the bottom of the stack are the reliability must-run units and contracted power. The generation associated with these units and contracts is scheduled and run regardless of operating cost. The generation from NSPI-owned wind and hydro resources is next in the stack. These low variable cost resources are generally scheduled to run at available output unless some capacity is held back to provide reserve. The dispatch of the Wreck Cove hydro facility is more nuanced. Although low cost, it is not necessarily dispatched at full output in order to manage limited water supply and to be available to provide energy quickly when needed. The combine-cycle gas, coal/pet coke, and gas-fired steam turbines units are next in the stack. It is usually one of these units that is marginal—the most expensive unit dispatched. The Port Hawkesbury (PH) Biomass unit is near the top of the stack. Although often uneconomic, it frequently operates at the request of PHP under the terms of PHP's LRT. In this case the PH Biomass unit is like the must-run units at the bottom of the stack. At the very top of the stack are the oil-fired combustion turbines. These units can be started very quickly to respond to immediate system needs, and thus provide significant value to system reliability; however, the cost of operating these units is very high.

Incremental costs are used to determine the merit order stack. Typically, the largest component of incremental cost is the fuel cost. Variable operation and maintenance costs (VOM) and transmission losses are also included. The components of incremental cost are shown in the following equation:

[redacted]

Environmental costs are included in the above cost equation through the fuel price and through the environmental fuel adder. During the Audit Period, NSPI managed its SO_2 and mercury emissions constraints by adjusting the fuel mix—blending more expensive lower sulphur content fuel with less expensive higher sulphur content fuel. Thus, the cost of reducing sulphur in the fuel, and by extension SO_2 and mercury emissions, is reflected in the fuel price. Mercury compliance costs are additionally reflected in the cost equation through an explicit fuel price adder for each solid fuel generator. The inclusion of environmental costs for a specific generation unit move it up in the merit order and cause it to be dispatched less often. Through the fuel blend and fuel cost adder, NSPI is able to optimize its air emissions constraint and mercury compliance costs.

The actual dispatch of generation units can deviate from the least cost dispatch to accommodate constraints on the system. For example, transfer limits on transmission corridors can result in output limits on specific generating plants. Security constraints that consider the impact of the loss of large transmission or generation resources on the system, as well as voltage or other operational needs, can require modifications to the least cost dispatch. The need for short-term operating reserves or ancillary services can require out-of-merit dispatch. NSPI requires a minimum of 75 MW of 30-minute reserve and a minimum of 168-171 MW of 10-minute reserve (of which 32–33 MW must be synchronized reserve). Operating reserves must be held on units that are either producing energy or that can produce energy within the required timeframe. Sometimes this requires lower cost units to be operated at less than full output (to carry the reserve capacity), while higher cost units are dispatched. Last, the dispatch process must take into account the physical capabilities of specific units such as their ramp rates, start-up times, and minimum operating levels. This again may result in a higher cost unit being dispatched when a lower cost unit cannot produce the needed energy within the required time.

X.A.2. Commitment and Dispatch Process

The following are the steps in NSPI's process for committing and dispatching its units:

- Each week, system security engineers at the ECC run studies to determine transmission transfer limits, and, if necessary for transmission operation, limits on specific generating units. The limits are communicated to NSPI marketing personnel and manually updated in GenOps for the day-ahead and real-time dispatch schedules.
- At 9:00 AM on the day prior to the operational day, an initial run of the GenOps model is made using current information on generation units, wind and load forecasts, and system conditions, to produce an initial economic dispatch schedule. NSPI runs the GenOps model for the three upcoming days; this is how NSPI is able to optimize its commitment

of generation units, a point we discuss below. A report with the dispatch results is produced and electronically distributed to ECC, plant personnel, and other key stakeholders.[1]

- At 9:30 AM, Monday through Friday, a morning conference call is held with generating plant operations staff, ECC, and the day-ahead and real-time energy marketers. The status of each thermal unit and combustion turbine (CT), and each unit's availability for the next day are discussed. Other scheduling and dispatch issues are also identified and discussed.
- The GenOps model is run again based on the information provided in the morning conference call.
- If a unit needs to be taken offline for maintenance or because it is not chosen from the dispatch stack, a generation outage request is prepared and submitted to the system operator and ECC for evaluation and approval.
- Gas requirements for the next gas day are determined and forecasted.
- Further discussion of generation uncertainties, particularly in the wind forecast, are discussed and can result in revisions to the unit commitment schedule.
- Outage requests are considered and accepted by the system operator and ECC.
- Based on the most recent system information and market outlook, gas transactions for the next gas day beyond the base contract amount are finalized.
- By 11:00 AM but no later than 1:00 PM, the finalized day-ahead schedule is sent to ECC.
- The energy marketing desk operates around the clock and remains in contact with the generating plants and ECC on a 24/7 basis. The energy marketing desk receives updated information on unit capabilities and status, system demand, wind forecast, industrial load, changes in fuel availability, and unplanned changes in transmission availability.
- Energy marketers monitor opportunities to import or export power to neighboring systems such as New Brunswick or New England, and schedule transactions, two hours before the operating hour, when they are economic or needed for reliability as determined by the system operator at the ECC.
- The 24-hour energy marketing desk submits hourly dispatch schedules (which adjust the day-ahead schedules) to the ECC based on the most recent available information.
- ECC dispatches the system using the hourly dispatch schedules and real-time system information.

Through the commitment and dispatch process, the most up-to-date information on load, wind generation forecast, weather conditions, fuel price and availability, generator status, emissions, transmission conditions, and system stability conditions is brought together and used to determine the

[1] Appendix R, Economic Scheduling & Marketing Requirements.

precise set of generators that will be operated to serve load at each moment in time. Some parameters are not fully modelled, such as the PH Biomass unit and natural gas prices, which we discuss below.

X.A.3. **Cooperative Dispatch**

New Brunswick Power (NBP) and NSPI have executed a cooperative dispatch agreement. The cooperative dispatch agreement is not a joint dispatch arrangement, but rather a contractual framework for bilaterally buying and selling energy on a voluntary basis. Settlement for bilateral transactions is based on an equal sharing of the net benefits.

Net benefits are calculated using system incremental and decremental costs. Net benefits occur in any given hour if the cost to produce incremental energy on one system is less than the cost avoided on the other by reducing production. The net benefit is the difference between the incremental and decremental costs.

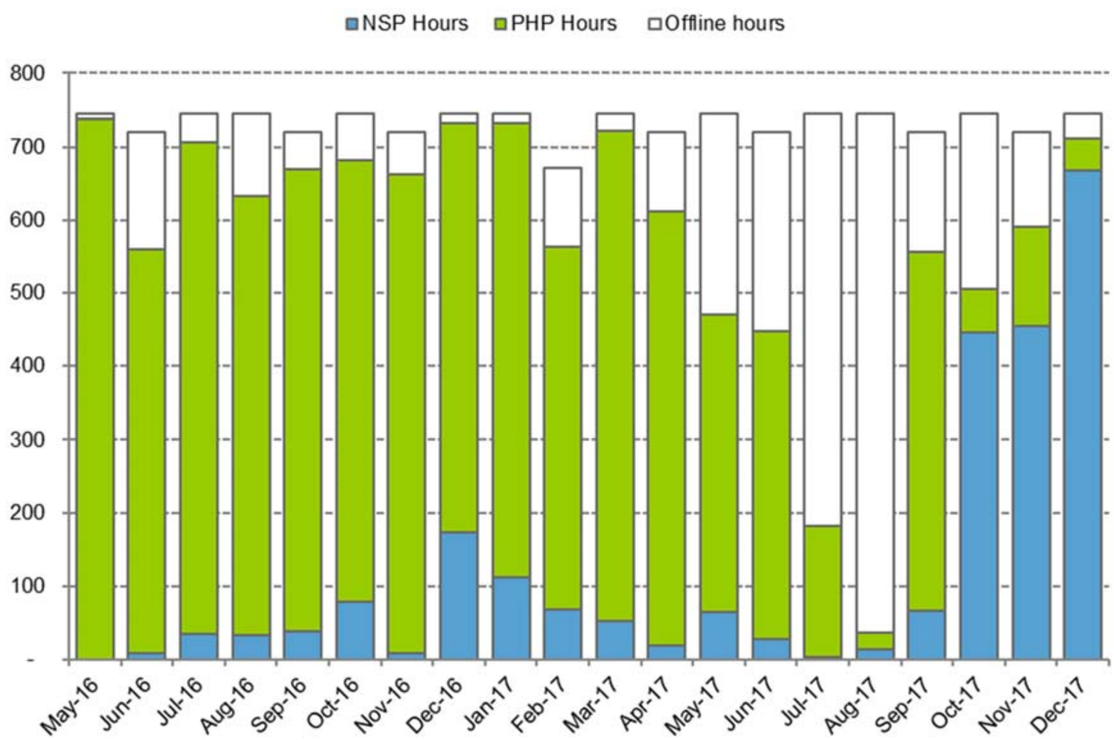
The cooperative dispatch initiative was projected to yield substantial benefits. However, the arrangement has not achieved the level of shared savings originally estimated—see our discussion of the specific level of benefits in the Power Purchases and Sales chapter. This is due in part to differences between the modeling assumptions used to estimate the benefits of the agreement and the reality of what occurs in actual practice. The model optimized dispatch between NBP and NSPI before evaluation of external markets, but in practice NBP markets energy externally first. NSPI has stated that the cooperative dispatch agreement will not progress to a fully integrated optimization of the two systems.

X.A.4. **Dispatch of Port Hawkesbury Biomass Generation Facility**

The dispatch of the PH Biomass generation facility is not determined through GenOps but is done in a separate evaluation outside the GenOps optimization. The unit is dispatched if it is determined to be economic. If the unit is determined *not* to be economic, the unit may still be run if PHP requests this. In this circumstance, PHP provides the fuel to run the unit and receives the energy as provided for under the tariff.

In the Audit Period, the operation of the PH Biomass facility was done primarily at the request of PHP—except in the fourth quarter of 2017. Figure X-2 shows the number of hours that the unit was operated economically by NSPI (“NSP Hours”), operated under the LRT (“PHP Hours”), or offline during the Audit Period.

Figure X-1. Operation of the Port Hawkesbury Biomass Facility (Hours)



The capacity of the PH Biomass facility is small—63 MW nameplate—relative to PHP's maximum load of approximately 222 MW. PHP load is incorporated in the commitment process according to the terms of the LRT, which requires NSPI to provide PHP forecasted incremental energy costs under the tariff for various operating points of the paper mill. This process is described more fully in the final chapter of this report. The energy marketing desk keeps in contact with PHP on a 24-hour basis to incorporate any changes to PH Biomass operation or PHP load into the system dispatch plan.[2]

X.B. Findings

X.B.1. Dispatch Approach and Implementation

NSPI uses a process for committing and dispatching its units that is standard in the industry. The process, starting with the 9:30 AM morning conference call and continuing through the subsequent series of communications and processes, is well established and staffed by experienced and knowledgeable personnel. Bates White finds that the NSPI process is sound and appropriate. We find that the tools used in the process, including the GenOps model for optimization of commitment and dispatch, is appropriate

2 Fuel Manual Revision 10, Appendix R.

for NSPI's system. In addition to this overall, general positive finding, we have three other findings that lead us to provide recommendations in each case.

X.B.1.a. Documentation

First, in terms of documentation, NSPI's commitment and dispatch process is contained in Confidential Appendix R of the Fuel Manual. While not unreasonable in its content, we note that Appendix R does not *require* NSPI to follow economic commitment and dispatch, subject to system security constraints.[3] One way to improve and codify the importance of economics in commitment and dispatch decisions would be to edit Appendix R to include a sentence that states that NSPI's marketers will seek the economically lowest cost solution in commitment and dispatch, subject to system security constraints. We include a recommendation to this effect below.

X.B.1.b. Natural Gas Price Modeling Limitations

Second, we tested NSPI's dispatch results at a simplified, high level and in doing so, confirmed that, generally, NSPI is following the dictates of economic dispatch. However, certain data challenges make it impossible for us to evaluate NSPI's dispatch with complete precision.

Our high-level analysis of the dispatch results during the Audit Period was intended to check if those results, at an overall aggregate level, were consistent with least cost dispatch. To do this, we examined the hourly incremental costs of the NSPI generation units in the hours that they were producing at or above minimum load and compared the average incremental costs to capacity factors over each of the two years in the Audit Period. At a high level, after system and unit constraints are taken into account, we would expect to see low incremental cost units dispatched more frequently than high incremental cost units, and this is borne out for most units. However, we identified certain cases in which this was not the case. Figure X-3 shows average incremental costs and capacity factors for generation units in 2016.

[3] Fuel Manual Revision 10, Appendix R.

Figure X-2. Incremental Cost and Capacity Factors, 2016

Unit	Nameplate Capacity[4] (MW)	Reported Availability Factor (FAM Report)	Annual Generation (MWh)	Reported Capacity Factor[5] (FAM Report)	Average Incremental Cost ($/MWh)
Tufts Cove 1	100	43.0%	39,287	5.0%	[redacted]
Trenton 6	160	93.0%	1,146,813	77.0%	[redacted]
Point Aconi 1	165	85.0%	1,217,639	72.0%	[redacted]
Point Tupper 2	150	94.0%	1,056,125	75.0%	[redacted]
Tufts Cove 5	54	90.0%	254,225	55.0%	[redacted]
Tufts Cove 4	54	87.0%	252,918	57.0%	[redacted]
Tufts Cove 3	150	92.0%	632,997	46.0%	[redacted]
Trenton 5	150	78.0%	773,611	55.0%	[redacted]
Tufts Cove 2	100	85.0%	198,356	23.0%	[redacted]
Lingan 4	150	64.0%	530,249	37.0%	[redacted]
Lingan 1	150	99.0%	823,524	56.0%	[redacted]
Lingan 3	150	98.0%	721,443	50.0%	[redacted]
Lingan 2	150	99.0%	320,894	22.0%	[redacted]
Point Hawkesbury Biomass*	63		12,283	3.3%	[redacted]
Burnside 3**	30		409	0.2%	[redacted]
Burnside 1**	30		1,241	0.5%	[redacted]
Victoria Junction 2**	30		106	0.0%	[redacted]
Burnside 2**	30		964	0.4%	[redacted]
Victoria Junction 1**	30		154	0.1%	[redacted]
Tusket CT**	24		367	0.2%	[redacted]

Comparing incremental costs and capacity factors, we see that the lowest cost units—Trenton 6, Point Aconi 1 and Point Tupper 2—have the highest capacity factors.[6] The highest cost units—Burnside, Victoria Junction, and the Tusket CT—have the lowest capacity factors. These results reflect merit order dispatch and are in line with expectations, and they suggest that NSPI is following economic dispatch principles. A capacity factor of 56% was reported for the PH Biomass unit in the FAM data. We adjusted the capacity factor to remove the hours that the unit is run at PHP's direction under the LRT (i.e., when it is not economic for NSPI) and the hours that the unit was operated as must-run (through April 2016). The adjusted capacity, factor reflecting economic dispatch, is also in line with the merit order.

Looking further, however, several units in the middle of the stack are out of merit order. Tufts Cove 3 and Tufts Cove 2 are both relatively low-cost units but have lower capacity factors than higher cost units such as Lingan 1 or Lingan 3. Conversely, Lingan 1 and Lingan 3 are relatively expensive units but have higher-capacity factors than lower-cost units.

The dispatch findings are similar in 2017, including the out-of-merit finding. As shown in Figure X-4, Tufts Cove 1 and Tufts Cove 2 are low-cost units but have relatively low-capacity factors. Their capacity factor—39% and 35%, respectively—are lower than those of the Lingan units 1, 3, and 4, which are 45%,

4 Nameplate Capacity as reported in the 2016 FAM Annual Report section A-2.

5 Capacity Factors as reported in the 2016 FAM Annual Report, section A-6, unless otherwise noted.

6 Tufts Cove 1 was on outage for most of 2016. See the Power Plant Performance chapter for more.

55%, and 43%, respectively. But their costs—Tufts Cove 1 and 2 have incremental costs of [redacted] and [redacted] respectively—are lower than the costs of the units that are operated *more* frequently—Lingan Units 1, 3, and 4 have incremental costs of [redacted], [redacted], and [redacted], respectively.

Figure X-3. Incremental Cost and Capacity Factors 2017

Unit	Max Net Capacity[7] (MW)	Reported Availability Factor (FAM Report)	Annual Generation (MWh)	Reported Capacity Factor[8] (FAM Report)	Average Incremental Cost ($/MWh)
Tufts Cove 1	78	86.0%	264,084	39.0%	[redacted]
Trenton 6	154	75.0%	959,338	66.0%	
Tufts Cove 4	49	94.6%	250,781	54.0%	
Tufts Cove 5	49	82.7%	210,891	49.0%	
Tufts Cove 2	93	76.6%	306,065	35.0%	
Point Tupper 2	150	85.9%	968,181	70.0%	
Trenton 5	150	88.7%	880,916	62.0%	
Point Aconi 1	168	86.5%	1,212,470	83.0%	
Tufts Cove 3	147	66.5%	412,197	30.0%	
Lingan 2	153	73.4%	322,541	23.0%	
Lingan 3	153	97.1%	795,896	55.0%	
Lingan 4	153	90.6%	619,338	43.0%	
Lingan 1	153	85.1%	652,655	45.0%	
Point Hawkesbury Biomass*	63		62,250	11.3%	
Burnside 3**	33		2,165	0.7%	
Burnside 2**	33		709	0.2%	
Burnside 1**	33		2,909	1.0%	
Victoria Junction 2**	33		123	0.0%	
Tusket CT**	33		311	0.1%	
Victoria Junction 1**	33		347	0.1%	

We probed this issue at length with NSPI. We determined that there were two general reasons that the Tufts Cove-Lingan data anomaly was occurring. First, there are legitimate operational issues that can lead to out-of-merit commitment and dispatch. Transmission congestion and system reliability or security limitations that lead to must-run designation for certain generating units can upset the otherwise economic merit order. Here, we found only limited evidence of such factors influencing the results.[9] Second, NSPI did not provide us with the full incremental cost of natural gas to fuel its gas-fired units (such as those at

7 Max Net Capacity as reported in the 2017 FAM Annual Report section A-2.

8 Capacity Factors as reported in the 2017 FAM Annual Report, section A-6, unless otherwise noted.

9 On the NSPI system, the most significant transmission interface that can influence least-cost dispatch is Cape Breton Export, which can limit flow from generation in eastern Nova Scotia to the load centers west of Onslow. During the Audit Period, NSPI estimates that congestion on this interface may have resulted in out-of-merit dispatch for a total of just seven hours in 2017 (0.08% of the time). System reliability or security limitations can also result in the dispatch of higher cost generation when lower cost generation is available. Generation at Tufts Cove was treated as must-run to address these types of limitations, including the potential for transmission overload for a single contingency, for a total of 563 days in the 2016–2017 period. This does not appear to have caused the Tufts Cove generation to be run out of merit. In 2016 and 2017, to provide voltage control to Sydney area load and the bulk power transmission system, dispatch instructions required either two units on-line at Lingan or one unit at Lingan plus Point Aconi. Point Aconi had high-capacity factors in 2016 and 2017; therefore, the requirement was satisfied most of the time with one unit on-line at Lingan. In 2016 and 2017, one unit was must-run at Lingan during 73 and 61 days, respectively. Two units were must-run at Lingan during 6 and 30 days, respectively. This requirement may explain some of the out-of-merit dispatch of the Lingan units.

Tufts Cove) that it uses in GenOps. This is what we believe is the driver of the Tufts Cove-Lingan data anomaly. Specifically, NSPI models natural gas prices in GenOps for the day-ahead timeframe using three price-quantity pairs for natural gas costs. So for up to some amount of natural gas (say, from 0 to 10,000 MMBtu), NSPI specifies a price; from that quantity to the next quantity (say, from 10,001 MMBtu to 30,000 MMBtu), NSPI specifies another price; and for a third quantity (say, 30,001 MMBtu and higher), NSPI specifies a third price. GenOps then optimizes commitment and dispatch of Tufts Cove (and the other units) using those price assumptions for natural gas. In the incremental cost data provided to us as part of the audit process, NSPI provided one incremental cost for Tufts Cove units running on natural gas and another cost for running on fuel oil. The single gas incremental cost was based on the lowest gas price modelled in GenOps for the day-ahead model runs. This necessarily biased our data and analysis, resulting in understated costs for Tufts Cove.

As a result, our concern here is not with NSPI's economic dispatch; rather, it is with the reliance of NSPI's dispatch results on its natural gas price expectations, as well as the auditability of the data itself. On the former point, NSPI is making assumptions about the price of gas that may not materialize; however, because NSPI buys most of its gas at daily-settled prices, there is an inherent risk—and potentially some cost—associated with NSPI's ability to accurately specify the price of natural gas in GenOps. This is true not only in the day-ahead timeframe but also in real time, where intra-day natural gas prices can move quickly and can be based on offers from counterparties that expire faster than the time it takes to complete a GenOps run. On the latter point, it becomes difficult for the Fuel Auditor to determine precisely the true cost of generation at Tufts Cove, as our analysis above bears out. We provide a recommendation on this point below.

X.B.1.c. Decisions Made Outside GenOps

We note that there are two aspects of NSPI's commitment and dispatch process that are done outside of the GenOps model. The first is the decision to dispatch the PH Biomass unit. A calculated PH Biomass price is compared to the forecasted marginal cost from GenOps. If the PH Biomass unit is determined to be economic it is added to the dispatch schedule. Second, because gas prices can change significantly within a day, the decision to dispatch one or more of the Tufts Cove units, or to increase the production of one or more units, is sometimes done outside of the day-ahead GenOps optimization.

While it may happen less frequently, the decision to commit one or more Lingan units can occur after the day-ahead GenOps model is run when a significant system event occurs. Such an event can include generator trips or shortfalls in actual wind generation output compared to forecasted wind output. The commitment and dispatch of units outside of GenOps based on localized optimization will not consider the overall system impacts of the dispatch decision and can result in a sub-optimal solution for the system as a whole. We provide a recommendation related to these items below.

X.B.2. Operating Reserves

As we explain in the Power Plant Performance chapter, NSPI is required to carry operating reserves to ensure reliable operation if there are unexpected generation or transmission problems that require additional generation to start energy production in a short period of time. Also, as we note in that chapter, we found evidence that NSPI was carrying surpluses of operating reserves throughout the Audit Period. We address that issue in detail here.

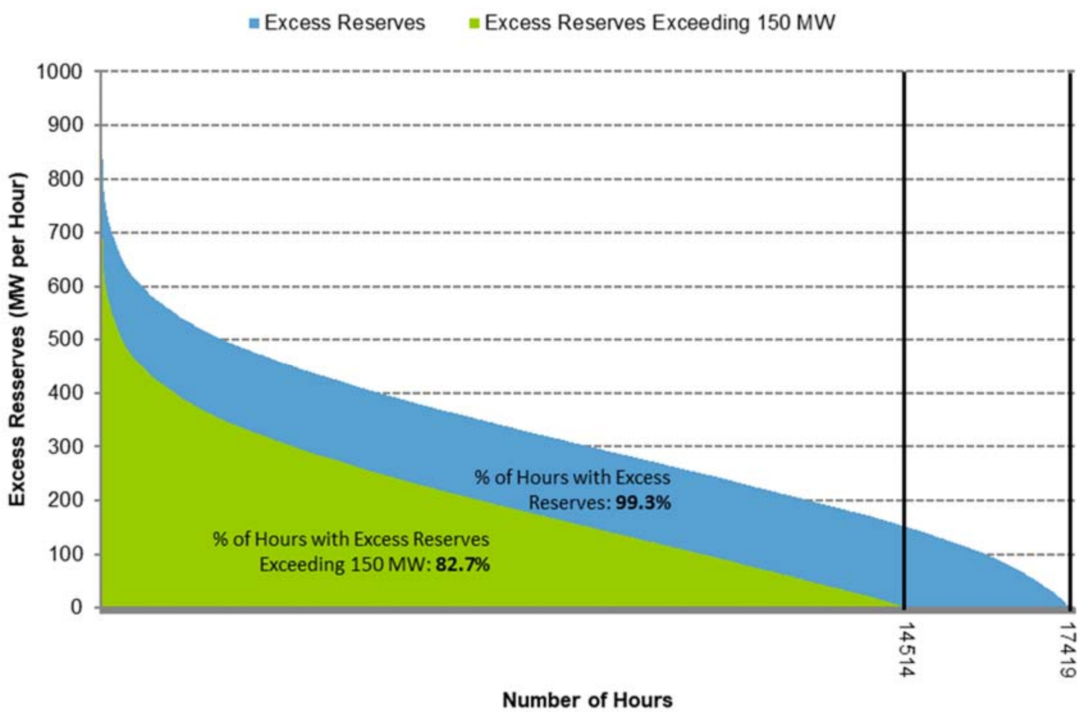
A surplus of operating reserves results when more units are committed and are available to provide energy and reserves than are needed in a given hour. A surplus of operating reserves is not necessarily evidence of suboptimal decision making, such as excess unit commitment—load and wind can vary significantly from hour to hour, meaning that the amount of operating reserves can wax and wane over the short run. Moreover, since turning units on and off imposes certain costs on the system, it may be economic to carry surpluses of operating reserves during hours of, say, low load and high wind, to avoid start-up costs when the wind dies and load increases.

Nevertheless, surpluses of operating reserves—especially those of the magnitude we observed on NSPI's system—demand attention, as they can incur costs on FAM customers. Those costs can be observed in two ways. First, excess commitment can result in the operation of units below their most efficient levels—specifically, the steam combustion units have higher heat rates at lower levels of operation. Thus, excess unit commitment can result in higher fleetwide heat rates and therefore less efficient operations. Second, if excess unit commitment is truly pervasive, it could imply that the system could still operate reliably—and at a lower cost—even if an existing generating unit was retired or otherwise shut down.

We reviewed NSPI's operating reserves data for each hour of the Audit Period. We found that in 82.7% of the hours during the Audit Period, the amount of operating reserves (30-minute reserve and 10-minute reserve) scheduled by NSPI exceeded the required amount by 150 MW or more. This appeared to us to be a high level of operating reserves surpluses, and not consistent with best industry practices.[10] Figure X-5 shows excess reserves on the NSPI grid in each hour of the review period ordered from highest to lowest.

[10] In areas of North America where there are markets for reserves, system operators procure the required amount of operating reserves. Generation owners that are selected to provide reserves are required to perform on their obligations or face financial consequences. In market-based systems, units that are not compensated for provision of reserves are less likely to be dispatched near minimum load, as the unit is unlikely to be able to recover its costs at this level of operation.

Figure X-4. Operating Reserves in Excess of the Requirement (by Hour)



It is common in electric systems to observe some level of operating reserve surpluses, and we would expect to see such surpluses at times on the NSPI system. NSPI's load profile has two daily peaks, an evening and a morning peak. Generation units are frequently kept on overnight operating at low levels to have sufficient generators available to serve the morning peak. This can result in excess operating reserves in the off-peak hours. We find, however, that the magnitude of the surpluses of operating reserves appears excessive and warrants deeper examination.

To quantitatively determine if NSPI's operating reserves are an inevitable function of its system's idiosyncrasies (high wind penetration, morning peak, and sub-optimal ramping capability[11]) or if NSPI is potentially committing more generation in the day-ahead timeframe than is truly needed—thereby imposing additional and unnecessary costs on the system—we sampled six hours during the Audit Period in which there were large surpluses of operating reserve. We asked NSPI to demonstrate that the unit commitment decisions were lowest cost.

In all cases, we were satisfied that NSPI had acted reasonably. In two of the six hours we sampled, NSPI had invoked its Emergency Services Restoration Plan, a Board-filed set of protocols followed by NSPI in preparation of and during storm events. In these cases, NSPI may commit units out of economic merit to prepare for contingencies related to a storm event, such as transmission outages. This is a common industry practice.

[11] See discussion of this point in the Power Plant Performance chapter.

In the other hours, NSPI demonstrated that the commitment results observed in those hours were optimal. NSPI did this by comparing (1) the cost of the actual day-ahead commitment schedule established for the day in which the sample hour fell with (2) the cost of the same day-ahead commitment schedule, assuming the de-commitment of the highest cost thermal generating unit (e.g., the highest cost Lingan unit). In two of the hours, the cost of the original day-ahead schedule was cheaper than that of the run with a thermal generating unit being de-committed. In a third case, the system would have been short of needed operating reserves in multiple hours, meaning the system would have violated reliability criteria. And in the fourth case, while the day-ahead solution was shown to actually be more expensive than the run in which a unit was de-committed, the three-day-ahead scheduling run showed a lower overall cost. This was because the wind forecast showed a high degree of wind in the first day, but by day three was forecasted to fall precipitously, meaning that the de-committed unit would have to be replaced with higher-cost generation, such as the oil-fired combustion turbines, resulting in a higher overall three-day cost.

We find, therefore, that NSPI has followed the principles of economics in its unit commitment decisions during the Audit Period. Nevertheless, we note that this short-term look at NSPI's fleet does not consider the sustaining capital costs of carrying the units themselves. This is one reason we are recommending in the Power Plant Performance chapter a regular, more robust IRP process that would consider the overall cost impact of maintaining or altering the makeup of the NSPI generating fleet. That IRP process would also closely scrutinize NSPI's peak load forecast and consider the optimality—not just the adequacy—of NSPI's planning reserve margin, which would help determine if NSPI was required to carry the planning reserves it currently carries.

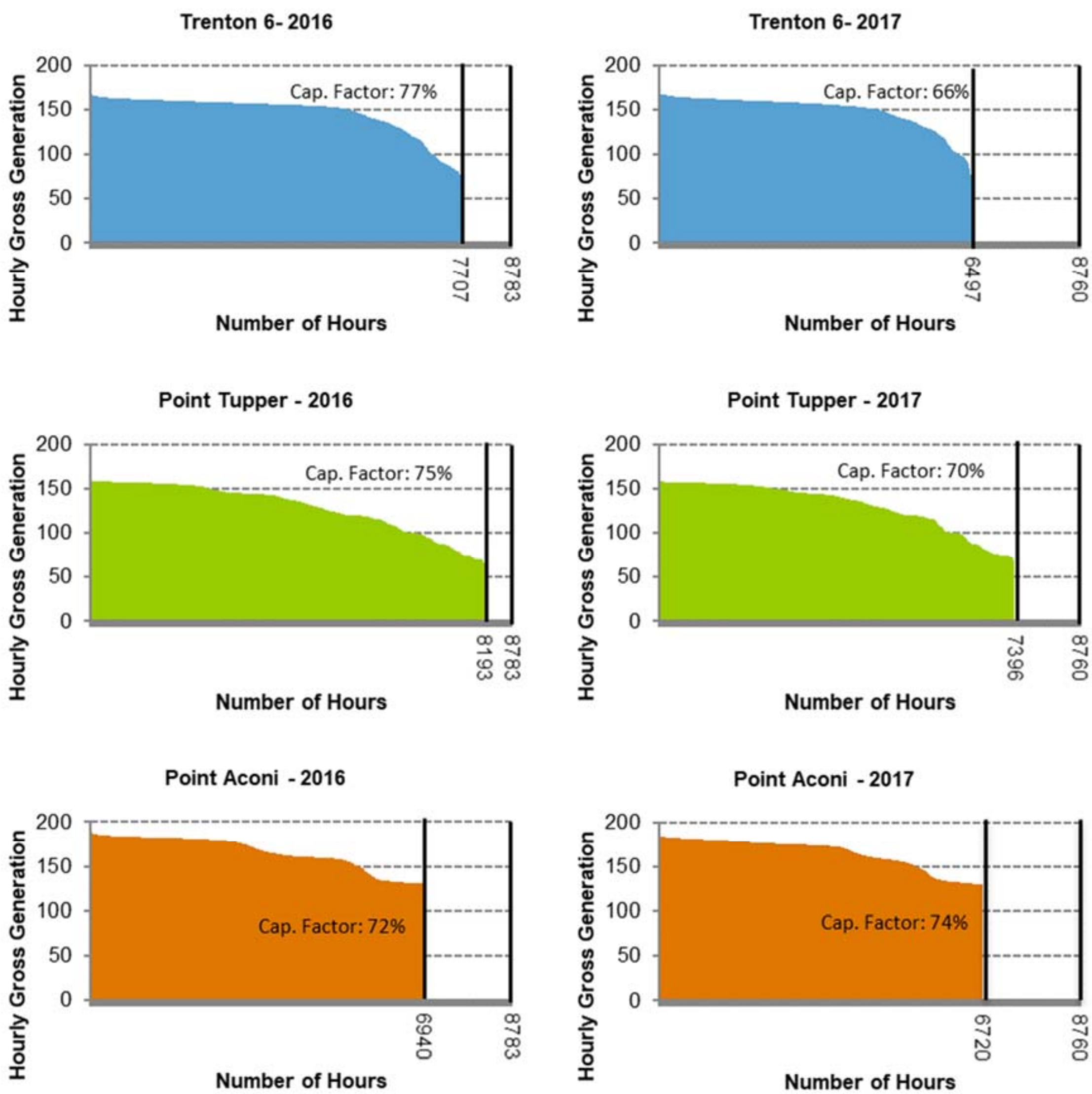
And while we do not find that NSPI violated the dictates of economic unit commitment and dispatch, we do note that the impact of its system realities does result in some of NSPI's thermal generating units operating at less efficient levels, which imposes costs on the system. We provide an illustrative look at these costs in the next section.

X.B.3. Costs of Operating Units at Lower Loading Levels

There is an inverse relationship between the efficiency—and thereby $/MWh cost—of a generating unit and its loading level. Operating at lower loading levels is generally less efficient and thus more costly on a dollar-per-megawatt-hour basis, while operating at higher loading levels is more efficient. NSPI recognizes that shutting down thermal units can increase capacity factors for the balance of the fleet and has shut down units for extended periods. For example, NSPI shut down Lingan 2 during the non-peak (spring, summer, and fall) season in the review period to avoid costs during this lighter-load period. The unit was then brought back on-line in the winter peak season to contribute to firm capacity. This is a positive step by NSPI to help increase the overall efficiency of the fleet.

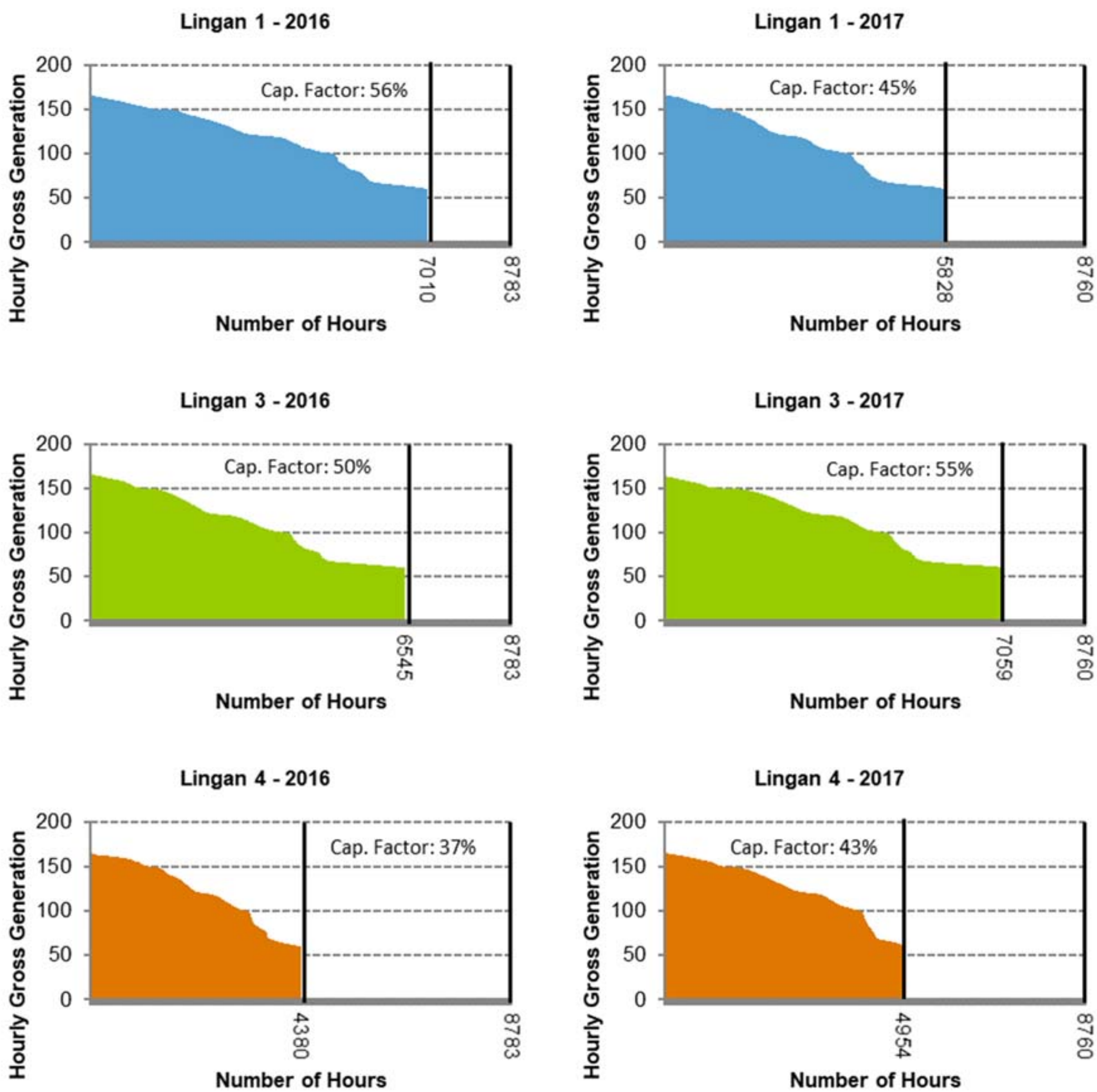
Figure X-6 shows the hourly loading of NSPI's high-capacity factor fossil units arranged from highest to lowest. These units run at efficient levels in most hours. This can be compared to Figure X-7, which shows the hourly loading of the Lingan units arranged from highest to lowest. The comparison of Figure X-7 to Figure X-6 shows a stark difference in the operation of the Lingan units.

Figure X-5. Hourly Generation of Trenton 6, Point Tupper, and Point Aconi



The Lingan units do not run at efficient levels in most hours. Note the relatively few hours that the units are operating near full output, the downward sloping line, and the many hours that the units are operated at their most inefficient minimum levels. These loading profiles indicate frequent cycling—turning the units on and off and ramping the units up and down to provide regulation and load following services. The operation of the units in this fashion increases operational cost.

Figure X-6. Hourly Generation of Lingan 1, Lingan 3, and Lingan 4



We estimated the impact on costs due to the increase in the heat rate (the amount of energy that it takes to produce a unit of electricity) that results from running the Lingan units at inefficient levels. We measured the change in costs that would result if the Lingan units had been operated at eco max, rather than at the level they actually operated.[12] The results are shown in Figure X-8.[13] To be clear, these results are indicative. They do not take into account joint optimization, operational considerations, or system

[12] The cost calculation was done for hours the unit was producing energy. It excludes hours that the unit was on but not producing energy.

[13] In Figure X-8, we estimate the savings in fuel costs associated with running the Lingan units at a more efficient heat rate. For the hours when gross generation is greater than 65 MWh, we calculate the fuel cost per MWh. We also calculate the fuel cost per MWh at 155 MWh (the value for maximum output). The difference between these two costs per MWh, times hourly generation, is the savings associated with running the units at a more efficient level for each hour.

constraints. These estimates have been prepared to give insight into the costs incurred from inefficient unit operation.

Figure X-7. Estimated Costs of Inefficient Unit Operation—Lingan[14]

Year	Lingan 1	Lingan 3	Lingan 4
2016	[redacted]		
2017			
Total			

The cost estimates in Figure X-8 also do not include the additional start-up, no-load, and cycling costs, also incurred by operating of the Lingan units as shown in Figure X-7. Start-up costs for the Lingan units can range from [redacted] per start, depending on the number of hours the unit has been off. The capital and maintenance costs of cycling the Lingan units are estimated to be approximately [redacted]. We find that the current operation of the Lingan units at inefficiently low loading levels is not cost free, as is shown in Figure X-8.

X.B.4. **Cooperative Dispatch**

Trading under the Cooperative Dispatch agreement with NBP is done on a manual basis two hours before real-time operations. The volume of trade conducted under the agreement has been less than expected. As we note in the Power Purchases and Sales chapter, Cooperative Dispatch has saved NSPI customers about $3.2 million over the Audit Period. However, according to the previous fuel auditor, the cooperative dispatch of the two systems was forecasted to save between $5 million and $20 million per year between the two parties, with NSPI's 50% share ranging between $2.5 million and $10 million per year.[15] Since the criteria under which a trade should be done are well defined in the agreement—NSPI and NBP transact if the delta between the incremental price and the decremental price is greater than [redacted]—we find that more automation of the process could increase the trading and potential benefits under the agreement. At a minimum, a record of the incremental and decremental prices should be maintained, along with documentation explaining the decision not to trade when the criteria indicates a trade should have been done. We provide a related recommendation below.

X.B.5. **Liberty 2014–2015 Recommendations**

The Liberty 2014–2015 Audit Report included the following recommendation: "NSPI should regularly review the causes of any out of order dispatch to ensure that it is optimized for least-cost supply."[16] Subsequently, in its January 20, 2015, FAM Audit Decision, the Board directed NSPI to work

[14] Costs in $CAD.

[15] Liberty 2014-2015 FAM Audit Report, page IX-2.

[16] Liberty 2014-2015 FAM Audit Report, page IX-9.

with Liberty to develop a methodology to track deviations from a hypothetical ideal unconstrained dispatch and to estimate the impact of those deviations.

In response, NSPI has conducted quarterly high-level evaluations of system constraints that may cause out-of-order dispatch by comparing the historical dispatch against a historical hypothetical constraint-free dispatch. The results of these evaluations are summarized in a report that is distributed annually to senior managers. The report provides an estimate of the impact of defined constraints and projects that will assist in relieving these constraints. Bates White has reviewed the 2016 report. The report finds that the two largest items that contribute to out-of-order dispatch are Commitment Lock and Operational Constraints. The Commitment Lock is the additional unit commitment after consideration of (1) the use of only 80% of the wind forecast in the day-ahead commitment, (2) unit risk that is not captured in unit modeling, (3) load and wind forecast risk, and (4) market pricing risk. Operational Constraints is a measure of uneconomic dispatch calculated as the difference between the actual dispatch and the commitment lock run. The cost of these two items was estimated to be [redacted] in 2016. Through a collaborative process, as of July 12, 2017 (the date of the 2016 report), almost 100% of forecasted wind is now used for day-ahead planning and unit commitment. This is expected to improve the dispatch in the Commitment Lock. In December 2017, NSPSO implemented a Real-Time Economic Dispatch program that automatically dispatches generators economically.[17] (Prior to this time, actual dispatch of the generation fleet was managed manually by NSPSO using information provided by NSPI Energy Marketing.) The automated process is expected to decrease the out-of-merit dispatch associated with the Operational Constraints. We provide a recommendation on this matter below.

X.C. Conclusions

Conclusion X-1: The commitment and dispatch process used by NSPI is standard and appropriate. It involves experienced and knowledgeable staff who communicate at appropriate times. The modeling tools are appropriate for the NSPI system.

Conclusion X-2: The Real-Time Economic Dispatch program implemented by NSPSO in December 2017 is a concrete positive step toward reducing uneconomic dispatch in real-time operations.

Conclusion X-3: The Fuel Manual's Appendix R—which contains NSPI's processes for economic commitment and dispatch—could be improved by codifying the importance of finding the lowest cost commitment and dispatch solution, subject to system security constraints. (Recommendation)

Conclusion X-4: NSPI generally followed the principles of economic dispatch during the Audit Period. [redacted]

[17] Transmission constraints continue to be managed manually by the Energy System Operator working with the Transmission System Operator.

[redacted]
(Recommendations)

Conclusion X-5: NSPI followed economic principles in unit commitment during the Audit Period. That said, the realities of NSPI's system (high wind penetration, morning peak, and sub-optimal ramping capability) resulted in considerable surpluses of operating reserves in many hours during the Audit Period. This can impose costs on the system, some of which would not be captured in the timeframe considered in a unit commitment decision, such as the sustaining capital costs for excess generating capacity. Our recommendation in the Power Plant Performance chapter related to IRP planning is intended to require NSPI to consider the optimality of its planning reserve capacity and its related sustaining costs. We also include a recommendation below to track the instances and causes of operating reserve surpluses over 150 MW until the next IRP process. (Recommendation)

Conclusion X-6: NSPI now uses 100% of forecasted wind (as opposed to 80%) in day-ahead planning and unit commitment. This is a positive step toward reducing uneconomic dispatch costs.

Conclusion X-7: NSPI took steps during the Audit Period to increase the efficiency of the overall thermal fleet, such as by shutting down Lingan 2 for the majority of the Audit Period. Nevertheless, the Lingan units were often operated at lower loading levels, i.e., below their most efficient operating points, while the units were also ramped up and down and cycled on and off, all of which combine to impose significant costs on FAM customers each year.

Conclusion X-8: NSPI's Cooperative Dispatch Agreement with NBP provided benefits to NSPI's ratepayers during the Audit Period, although these benefits have been less than anticipated. This is largely driven by lack of automation in the process, which relies on bilateral communications between the two systems and in which NBP markets power first externally before transacting with NSPI.

Conclusion X-9: The Cooperative Dispatch Agreement is implemented on a manual basis. It relies on the manual exchange of cost information and offers to buy and sell. Automating parts of this process would facilitate and enhance trading opportunities. Since it is a bilateral agreement, it requires consent from NBP. (Recommendation)

X.D. Recommendations

Recommendation X-1: NSPI should seek to improve the auditability of Tufts Cove's incremental natural gas cost data. NSPI should revise Appendix R of the Fuel Manual to include its process for capturing natural gas prices in the day-ahead and real-time GenOps model runs and should retain data on natural gas prices used in commitment and dispatch decisions.

Recommendation X-2: NSPI should work to reduce commitment and dispatch decisions made outside of GenOps, such as those related to the PH Biomass unit and Tufts Cove. All commitment and dispatch decisions made outside of GenOps should be well documented.

Recommendation X-3: To help specify and track both the causes of NSPI's observed operating reserve surpluses and the relative contributions of factors such as the variability of wind output on those surpluses, as well as to help inform the next IRP plan, NSPI should document instances of operating reserve surpluses above 150 MW and document their cause(s). NSPI should continue this documentation for the shorter of one year or the start of the IRP process, as defined by a draft IRP plan filed with the Board.

Recommendation X-4: Subject to cooperation from NBP, NSPI should continue to automate the exchange of cost information with NBP under the Cooperative Dispatch Agreement. The automation should include proposed trades and document incremental/decremental prices and reasons that trades are not made when they appear to be economic.

Recommendation X-5: NSPI should revise Appendix R of the Fuel Manual to direct NSPI's marketers to seek the economically lowest cost solution in commitment and dispatch, subject to system security constraints.

XI. Power Purchases and Sales

XI.A. Background

Historically, NSPI's owned generation has provided the vast majority of power to NSPI's customers. For example, from 2013 through 2015, NSPI's generating fleet has provided about 87.4% of all energy to NSPI's customers.[1] The rest of NSPI's power needs is provided by unaffiliated third parties. In addition, NSPI can also export power to neighboring control areas—historically, this has been a very small amount, ranging from 0.1% to 0.3% of NSPI's total net system requirements.[2]

The sources and terms of the third-party purchases vary. They can be long-term power purchases—such as multi-year power purchase agreements (PPAs) or single-month contracts resulting from month-ahead RFPs—or shorter term, including day-ahead and real-time hourly transactions. The purchases can be for economic purposes or driven by public policy, such as Nova Scotia's Renewable Energy Standard.

NSPI's Fuel Manual contemplates both power import and power export transactions. For example, section 13.1 of the Fuel Manual allows NSPI's energy marketers to conduct day-ahead and hour-ahead power purchases and sales,[3] while section 13.3 dictates that NSPI undertake long-term power purchase agreements with the goal of securing "competitive pricing and value," sometimes through the use of competitive RFPs, along with "direct negotiations, supplier of choice agreements, and single sourcing" arrangements.[4]

Power purchases (and sales) are important elements of a healthy electric utility. Buying power from third parties can have numerous benefits, including procuring power at a price lower than the utility's marginal system price and enjoying the benefits of electric energy without the costs and risks associated with rate-based utility generating assets. Selling power can also benefit customers, either through the sales of excess energy during periods of high wind output and low load, or simply when high prices in neighboring regions provide economic trade opportunities.

XI.B. Findings

We provide our findings below, separated into three areas. We begin with purchased power, which includes long-term purchases, term RFPs, and short-term purchases (i.e., day-ahead and real-time

1 Data calculated from Liberty 2014-2015 Audit Report, page X-2.
2 Data calculated from Liberty 2014-2015 Audit Report, page X-2.
3 Fuel Manual Revision 10, section 13.1.
4 Fuel Manual Revision 10, section 13.3.

transactions). We next discuss power exports, which are all short-term transactions. We conclude with a discussion of the previous fuel auditor's recommendations related to power purchases and sales.

XI.B.1. Purchased Power

Over the two-year Audit Period, approximately [redacted] of NSPI's total net system requirement was served by NSPI-owned generation, while about [redacted] was served by third-party generation owners. Figure XI-1 below shows these data across both years of the Audit Period.

Figure XI-1. Ownership of Generation Serving NSPI Customers[5]

Generation Serving NSPI Customers (MWh)		
	2016	2017
Total Net System Requirement	[redacted]	
NSPI-Owned Thermal Generation		
NSPI-Owned Renewables		
Third-Party Power		
Percentage Share of NSPI Generation (%)		
Percentage Share of Third-Party Power (%)		

Over the past five years, the amount of energy being provided by third parties has grown steadily, from 11.8% in 2013 to 20.7% in 2017. This trend is shown in Figure XI-2 below.

[5] NSPI FAM Quarterly Report Q2017, Q6, 2(3).

Figure XI-2. Percentage of Third-Party-Provided Energy to NSPI Customers (2013–2017)[6]

[redacted]

The source—and cost—of this third-party power varies. NSPI reports its third-party power purchases in four categories:

a. **Imports:** Imported energy is energy that originates from neighboring control areas. During the Audit Period, NSPI was interconnected only with the New Brunswick system, and thus all import transactions occurred via the intertie with New Brunswick, though the source of that power could have been ISO New England, Quebec, or New Brunswick. The primary purpose of import transactions is economic—that is, NSPI seeks to import power when it is cheaper to do so than to produce or procure energy domestically. The quantity of energy imported from New Brunswick is limited by the availability of New Brunswick's transmission system and is forecast according to the Plan of Administration, which specifies the use of three-year average annual imports.[7] It is important to note that NSPI does not add any additional cost adders to imports, third-party power, or other non-NSPI-owned generation such as risk premiums, uncertainty adders, or any other costs that distinguish such resources from NSPI-owned generation. (We discuss import transactions in more detail below.)

6 Data compiled from NSPI FAM Quarterly Reports.

7 POA instructions with regard to New Brunswick imports quantity are reviewed and adjusted accordingly to address years that have been deemed outliers, in the context of present system conditions outlooks.

b. **IPP Wind:** NSPI lists 32 IPP-owned wind facilities—30 of which provided power to NSPI during the Audit Period. IPP wind prices are fixed pursuant to power purchase agreements with NSPI. NSPI is required to "take or pay" for the power provided by these resources. It does not curtail wind generators for economic reasons, but can curtail them for reliability reasons. In those cases, all wind generators are treated the same, regardless of their ownership or PPA arrangement: that is, their owners are not paid for such curtailments, and curtailment occurs in a fair, equitable manner.[8]

c. **IPP Other:** NSPI lists seven IPP-owned non-wind generators, five of which provided power to NSPI during the Audit Period. IPP non-wind prices are fixed pursuant to power purchase agreements with NSPI.

d. **COMFIT**: The COMFIT Program was a program that the government of Nova Scotia offered to enable community organizations to provide renewable electricity generation. No longer accepting new resources[9] but still allowing existing resources to extend their COMFIT agreements,[10] the program-allowed generators include hydro, small wind (< 50 kW), large wind, and biomass/biogas. COMFIT rates are fixed and defined by the Nova Scotia Department of Energy[11] pursuant to power purchase agreements with NSPI.

Notably, of the four categories of third-party power transactions listed above, only one is pursued primarily for economic benefit: imports. Thus, it is reasonable to expect to see the dollar-per-megawatt hour cost of import transactions to be lower than (or near) the cost of NSPI's owned marginal generation. Since the other third-party purchases—IPP Wind, IPP Other, and COMFIT—are driven by public policy goals and requirements, not economics, it would not be surprising to see the costs of such purchases to be higher than the cost of imports and/or NSPI's owned generation. As shown below in Figure XI-3, this is indeed the case: while imported power averaged [redacted] over the entire Audit Period, the cost of NSPI's third-party renewable energy purchases was considerably higher, ranging from [redacted] on average for IPP Wind energy to over [redacted] for both IPP Non-Wind and COMFIT energy.

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8 NSPI can curtail wind generators due to local transmission constraints or light load conditions. For the former, NSPI curtails resources with non-network transmission service first. For the latter, NSPI curtails generators by 33% (using a rotational list) until the needed reduction is achieved.

9 Government of Nova Scotia, "Minister Announces COMFIT Review Results, End to Program," August 6, 2015, *available at* https://novascotia.ca/news/release/?id=20150806001.

10 As noted below, NSPI executed 21 COMFIT contracts during the Audit Period, all with existing COMFIT customers.

11 Nova Scotia Department of Energy, "Community Feed-In Tariff Program Facts," *available at* https://energy novascotia.ca/sites/default/files/comfit_facts.pdf.

Figure XI-3. Cost of Third-Party Power Sources ($/MWh)

Cost of Third Party Power ($/MWh)			
	2016	2017	Total Average
Imports	[redacted]		
IPP - Non-Wind	$169.11	$121.33	$139.83
IPP Wind	$73.58	$73.05	$73.31
COMFIT	$135.97	$135.85	$135.90

Power imports, of course, come from sources outside Nova Scotia—they may come from New Brunswick, Quebec, Newfoundland, Ontario, or New England. But in all such transactions—no matter the source—NSPI relies on its lone interconnection point with New Brunswick. NSPI and New Brunswick are interconnected via three overhead transmission lines: one 345 kV line from Onslow, Nova Scotia, to Memramcook, New Brunswick, and two 138 kV lines from Springhill, Nova Scotia, to Memramcook, New Brunswick.[12] The territory intertie is subject to import and export limits that can vary with a variety of system conditions, such as Nova Scotia's system load level, New Brunswick's export levels to Prince Edward Island, the status of internal generation and transmission assets in both Nova Scotia and New Brunswick, and the status and conditions of New Brunswick's interties with Quebec and ISO New England.[13] NSPI currently faces a maximum import capability of 300 MW and a maximum export capability of 350 MW.[14]

During the Audit Period, NSPI was a net importer of power in all months except June 2017, when it was a slight net exporter of power. This is illustrated in Figure XI-4, which shows the average hourly net import amount over each month of the Audit Period.

12 NSPI 10-Year System Outlook, page 56, lines 3–6.

13 NSPI 10-Year System Outlook, Figure 27.

14 NSPI 10-Year System Outlook, page 56, line 26.

Figure XI-4. Average Hourly Net Import over Nova Scotia-New Brunswick Intertie (MW)[15]

[redacted]

Because all import/export transactions must rely on the New Brunswick-Nova Scotia intertie and because that intertie has limited capability, NSPI was ultimately limited in the amount of power it could import during the Audit Period. For example, during the Audit Period, we observed an average hourly firm available transfer capability over the intertie with New Brunswick of about 29 MW and about 203 MW of non-firm ATC.[16] Moreover, power imports also must be able to make their way from their source to the intertie, which requires transmission in New Brunswick. This is particularly true [redacted]. Below, we provide two conclusions related to the intertie capability of NSPI, and we include the intertie as part of our IRP recommendation in the Power Plant Performance chapter.

We provide our findings across three types of purchased power transactions. We begin with long-term purchases, followed by term RFPs, and conclude with a discussion on short-term transactions (both imports and exports).

15 Data compiled from NSPI OASIS, *available at* http://oasis nspower.ca/en/home/oasis/monthly-reports/hourly-net-energy-flows-ns-nb-interconnection.aspx.

16 NSPI OASIS data, *available at* http://oasis.nspower.ca/en/home/oasis/monthly-reports/hourly-new-brunswick-intertie-ttc-atc.aspx.

XI.B.1.a. Long-Term Purchases

NSPI's Fuel Manual states that NSPI will undertake longer-term power purchases "with the goal of competitive pricing and value."[17] The Fuel Manual notes that "[c]ompetitive bidding by RFPs shall be a common approach, but is only one of a suite of strategies," including "[d]irect negotiations, supplier of choice agreements, and single sourcing," all with the purpose of attempting to "realize value."[18]

During the Audit Period, NSPI was counterparty to a total of [redacted] PPAs, [redacted] of which were executed during the Audit Period. NSPI also had power purchase contracts with 74 COMFIT resources, [redacted] of which were executed during the Audit Period.

Drilling deeper on these numbers and beginning with COMFIT numbers, Figure XI-5 shows that COMFIT resources cost, on average, about $135.00/MWh during the Audit Period and can cost several hundred dollars per MWh depending on the type of COMFIT resource. As noted above, COMFIT rates are set by the Nova Scotia Department of Energy and are not subject to negotiation. In terms of COMFIT quantities, NSPI absorbed approximately [redacted] of COMFIT output below forecast in 2016, while receiving about [redacted] more than budgeted of COMFIT output in 2017. On net, for the entire Audit Period, COMFIT output was about [redacted] below forecast—a deviation of about [redacted]. Figure XI-5 contains more detail about the COMFIT resources, showing the output and costs for each COMFIT resource during the Audit Period.

17 Fuel Manual Revision 10, section 13.3.

18 Fuel Manual Revision 10, section 13.3.

Figure XI-5. Output, Cost of COMFIT Resources (by COMFIT)[19]

Counterparty	Location	Capacity (MW)	2016 MWh	2017 MWh	Cost (2016)	Cost (2017)	Total Cost ($/MWh)
Colchester-Cumberland Wind Field	Spiddle Hill (Large Wind) COMFIT 072	0.80	[redacted]				
Town of New Glasgow	Town of New Glasgow	0.05					
Pockwock Wind Limited Partnership	Chebucto Pockwock Community Wind Project	10.00					
Watts Wind II Limited Partnership	New Glasgow	6.40					
Municipality of the District of Guysborough	Melford	0.10					
Municipality of the District of Guysborough	Goldboro	0.15					
Universite Sainte-Anne	Church Point	0.05					
Municipality of the County of Pictou	MOPC Riverton Small Wind COMFIT, Phase 1	0.15					
Municipality of the District of Shelburne	Sandy Point Road	0.05					
Avondale Community Wind Park Limited Partnership	Avondale Community Wind Park COMFIT 139	1.60					
Municipality of the District of Digby	MOD Anaerobic Digester Project	0.30					
HG Wind Limited Partnership	Gaetz Brook Wind Farm	2.30					
Colchester-Cumberland Wind Field Inc.	Spiddle Hill (Small Wind) COMFIT 158	0.10					
Town of Amherst	Fort Lawrence	0.05					
Municipality of the District of Chester	Kaizer Meadow	2.00					
ScotianWEB Limited Partnership	Isle Madame Community Wind Project	1.99					
Affinity Renewables Inc.	Fitzpatricks	1.40					
Affinity Wind LP	Kemptown	4.99					
Affinity Wind LP	Greenfield	3.20					
Affinity Wind LP	Limerock	4.99					
Celtic Current Limited Partnership	Bateston Community Wind Project	2.30					
Celtic Current Limited Partnership	Point Aconi Community Wind Project	1.90					
Celtic Current Limited Partnership	Cheticamp Community Wind Project	0.90					
Celtic Current Limited Partnership	Mulgrave Community Wind Project	2.30					
ScotianWEB Limited Partnership	St. Rose Community	1.99					
ScotianWEB Limited Partnership	Little River Community	1.99					
ScotianWEB Limited Partnership	Martock Ridge Community Wind Project	6.00					
ScotianWEB Limited Partnership	Nine Mile River Community Wind Project	4.00					
Watts Wind II Limited Partnership	Wedgeport	1.68					
Whynotts Wind Limited Partnership	Whynotts Community	4.00					
Truro Heights Wind Limited Partnership	Truro Heights	4.00					
Truro-Millbrook Wind Limited Partnership	Truro - Millbrook	6.00					
BA Wind Limited Partnership (Natural Forces Wind Inc.)	Aulds Mountain Wind Farm	4.60					
Valley Region Solid Waste Resource Management Authority	Kentville	0.05					
HG Wind Limited Partnership (Natural Forces Wind Inc.)	Hillside-Boularderie Wind Farm	4.00					
Windmill Holsteins Inc.	Shubenacadie	0.50					
ScotianWEB Limited Partnership	North Beaver Bank Community Wind Project	8.00					
ScotianWEB Limited Partnership	Black Pond Community Wind Project	1.99					
Watts Wind II Limited Partnership	Barrington (Shag Harbour)	3.20					
Halifax Regional Water Commission	Bedford	0.03					
Hefler Forest Products Ltd.	Hefler Forest Products Ltd.	3.10					
Municipality of the County of Pictou	MOPC Riverton Small Wind COMFIT, Phase 2	0.15					
Municipality of the District of Barrington	MOB Barrington Renewable Energy Project	0.05					
EM Wind Limited Partnership	Barrachois Wind Farm	4.00					
Gardiner Mines Wind Farm Limited Partnership	Gardiner Mines Wind Farm COMFIT 212	5.40					
Colchester Cumberland Wind Field Inc.	Tatamagouche	0.05					
Watts Wind III LP	Ketch Harbour	4.60					
Watts Wind III LP	Porters Lake	3.20					
Municipality of the County of Colchester	Kemptown - Colchester Balefill Facility COMFIT 401	0.05					
Municipality of the County of Colchester	Kemptown - Colchester Balefill Facility COMFIT 402	0.05					
Avondale Community Wind Park Limited Partnership	Avondale Community Wind Park COMFIT 164	0.05					
Avondale Community Wind Park Limited Partnership	Avondale COMFIT 239	0.05					
Port Hood & District Rec Commission	Cheticamp (COMFIT 284)	0.05					
Celtic Current - Mulgrave	Mulgrave (COMFIT 286)	0.05					
Port Hood & District Rec Commission - Cheticamp	Cheticamp (COMFIT 287)	0.05					
Celtic Current - Mulgrave	Mulgrave (COMFIT 288)	0.05					
Municipality of the District of Yarmouth	Rose Road (Wellington) COMFIT 370	0.05					
Municipality of the District of Yarmouth	Rose Road (Wellington) COMFIT 371	0.05					
Mi'kmaq-Wind4All Communities Limited Partnership	Amherst Community Wind Farm COMFIT 255	6.00					
Mi'kmaq-Wind4All Communities Limited Partnership	Amherst Community Wind Farm COMFIT 256	1.60					
ScotianWEB II Limited Partnership	Brenton Community Wind Project	1.99					
ScotianWEB II Limited Partnership	Hardwood Lands Community Wind	6.00					
ScotianWEB II Limited Partnership	Walton Community Wind Project	1.99					
ScotianWEB II Limited Partnership	Baddeck Community Wind Project	1.70					
372-859 Culloden Rd (Mun of Digby)		0.05					
326-Liverpool Wind Energy Storage Project		3.60					
191-New Victoria (Celtic Current LP)		2.35					
368-Point Acconi comfit (Celtic Current LP)		0.05					
369-Point Acconi comfit (Celtic Current LP)		0.05					
365-Cheticamp comfit (Celtic Current LP)		0.05					
366-Cheticamp comfit (Celtic Current LP)		0.05					
391-Cheticamp comfit (Celtic Current LP)		0.05					
395-cheticamp comfit (Celtic Current LP)		0.05					
243 - Chebucto Terence Bay (Chebucto Terence Bay Wind Field Ltd.)		7.05					
Total COMFIT		153.78	413,926	525,929	$56,112,866.00	$71,061,000.00	$135.31

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19 In some cases, the "Total Cost" column differs slightly from the provincially established PPA price, due to rounding. In addition, the MOPC Riverton Small Wind COMFIT Phase 1 project was the subject of a [redacted] accounting adjustment in May 2016 resulting from a revision in the commercial operation date and a billing true-up due to a metering issue. We note that our Figure XI-5 does not match the 2017 FAM Quarterly Report; NSPI addressed this issue with the Board in M08513.

The 21 new COMFIT contracts NSPI executed during the Audit Period are shown in Figure XI-6. In all cases, the contract rate is consistent with the rates dictated by the Nova Scotia Department of Energy for the given technology and size of the resource. Moreover, again, the 21 new contracts were executed with parties that had already been program participants prior to the COMFIT program being closed to new entrants in 2015.

Figure XI-6. New COMFIT Contracts Executed During Audit Period[20]

Counterparty	Term (Years)	Quantity	Price	Execution Date
Avondale Community Wind Park Limited Partnership	[redacted]			
Avondale Community Wind Park Limited Partnership				
Chebucto Terence Bay Wind Field Ltd.				
ScotianWEB II Limited Parntership (Hardwood Lands)				
ScotianWEB II Limited Parntership (Baddeck)				
Liverpool Wind Energy Storage Project Inc.				
Municipality of the District of Yarmouth				
Municipality of the District of Yarmouth				
Municipality of the County of Colchester				
Municipality of the County of Colchester				
Mi'kmaq Wind4All Communities Limited Partnership				
Celtic Current Limited Partnership				
Celtic Current Limited Partnership				
Celtic Current Limited Partnership				
Municipality of the District of Digby				
T.E. Boyle Farm & Forestry Limited				
Celtic Current Limited Partnership				
Celtic Current Limited Partnership				
Celtic Current Limited Partnership				
Celtic Current Limited Partnership				
Chestico Museum and Historical Society				
Chestico Museum and Historical Society				

Non-Wind IPP costs per MWh are also quite high. Notably, Brooklyn Energy—an Emera-owned, 30-MW biomass generator located in Brooklyn, Nova Scotia—provided approximately [redacted] of power during the two-year Audit Period at a cost of about [redacted], or approximately [redacted]. (We discuss Brooklyn Energy separately below.) Figure XI-7 provides further details on the output and cost of non-wind IPP resources over the Audit Period.

[20] NSPI FAM Quarterly Reports for all eight quarters of Audit Period, Q-3.

Figure XI-7. Output, Cost of Non-IPP Wind (by Source)[21]

Counterparty	Location	Capacity (MW)	2016 MWh	2017 MWh	Cost (2016)	Cost (2017)	Total Cost ($/MWh)
[redacted]							

The [redacted] new non-COMFIT PPA contracts NSPI executed during the Audit Period were all for tidal power. Two were with [redacted] which will not produce power until 2020, and the other was with Cape Sharp. Cape Sharp, a tidal resource co-owned by Emera, produced a *de minimis* amount of power during the Audit Period. According to NSPI, Cape Sharp is having operational issues and is not expected to be back online until sometime in 2018—although we note that the "Final In-Service Date" for the two Cape Sharp tidal PPAs is December 16, 2020. The Cape Sharp PPA requires NSPI to pay $530.00/MWh for the first 16,640 MWh generated each year, and $420.00/MWh for energy generated in excess of that. (The Black Rock PPAs have these same fixed prices, which are set by the Nova Scotia Department of Energy.[22]) All [redacted] contracts have terms of [redacted] years from the Commercial Operation Date of the units.

Figure XI-8 shows that IPP Wind purchases exhibited more reasonable prices that are, at least in part, a function of economies of scale. Still, however, the average IPP wind generator facility size that serves NSPI ratepayers is only about 13 MW, and some wind PPA prices seem now to be quite high—for example, the PPA with [redacted], a 30-MW facility, has a fixed price of [redacted] and has a 25-year term. This contract was executed in 2008. The [redacted] PPA is not unique—many of the wind IPP contracts were executed in the 2000s have terms in excess of 15 years. Prices at Sable and South Canoe are more favorable, providing over 600,000 MWh combined of energy over the two-year Audit Period for, on average, less than [redacted], as shown in Figure XI-8; however, these resources are unique in that both of these resources were the result of a competitive solicitation conducted by the Nova Scotia Renewable Electricity Administrator and are currently co-owned by NSPI. Therefore, NSPI pays third parties for [redacted] of the output from each facility, and owns the rest. Figure XI-8 shows all output from the two facilities, but includes only the costs paid to the third parties. Thus, the dollar-per-megawatt hour prices for Sable and South Canoe listed in Figure XI-8 are [redacted] of the actual PPA prices.

[21] We note that the $/MWh cost for the *de minimis* amount of energy provided by Cape Sharp Tidal is below the contract rate of $530.00/MWh. We note later in this chapter that the unit had operational issues during the Audit Period.

[22] Nova Scotia Department of Energy, "Developmental Tidal Feed-In Tariff Program," *available at* https://energy.novascotia.ca/renewables/programs-and-projects/tidal-fit.

Figure XI-8. Output, Cost of IPP Wind (by Source)

Counterparty	Location	Capacity (MW)	2016 MWh	2017 MWh	Cost (2016)	Cost (2017)	Total Cost ($/MWh)
[redacted]							

In developing our findings, we reviewed NSPI's power purchase agreements. One—the Brooklyn Energy facility's PPA—requires additional discussion, which we provide below.

XI.B.1.a.i. Brooklyn Energy Facility PPA

The Brooklyn Energy facility is an Emera-owned, 30-MW biomass generator located in Brooklyn, Nova Scotia, that uses a conventional steam turbine fueled primarily by wood but can also be powered by fuel oil. During the Audit Period, the Brooklyn facility provided approximately [redacted] of power at a cost of about [redacted], or approximately [redacted]. To put these numbers in perspective, NSPI spent about [redacted] (gross) on fuel and purchased power [redacted] on a net basis),[23] meaning Brooklyn Energy's cost to FAM ratepayers was [redacted] of total gross FAM costs and [redacted] of total net FAM costs, while providing just [redacted] of net generation during the Audit Period.

The high dollars-per-megawatt-hour price of the Brooklyn PPA of [redacted], which is almost [redacted] the average FAM costs per MWh for the Audit Period,[24] as well as the mismatch between contribution to FAM costs and contribution to net generation, warranted a closer look at this PPA. Moreover, the Brooklyn facility is owned by NSPI's parent, Emera.

The PPA that underlies the Brooklyn Energy facility was signed on June 30, 1992, and will expire in 2028. The original counterparty to the PPA was Polsky Energy Corporation. The history of the PPA's transition from Polsky to Emera is outside the scope of our work. We focused only on two questions: (1) Is NSPI administering the PPA in a manner that is best for FAM ratepayers? (2) Has NSPI had the chance to collect damage payments or even terminate the contract under its existing terms and conditions, and not done so? We address both questions here.

The PPA works as follows. Each day, Brooklyn Power provides NSPI with the plant's daily availability, which includes available energy for capacity, which is called a "Seller's Schedule," incremental energy, decremental energy, and both minimum and maximum load of the plant. NSPI then elects a volume between the minimum and maximum. NSPI's election can have a significant impact on the amount paid to Brooklyn for its energy.

There are four pricing components in the Brooklyn PPA:

- "Capacity Energy" is paid a fixed rate of [redacted], updated annually for inflation. Capacity energy is the actual monthly metered energy generated each hour up to the daily dispatch level requested by NSPI.
- "Incremental Energy" has a fixed component [redacted]) and a variable component, which is adjusted downward as the difference between Brooklyn's costs and the system marginal price increases. Incremental Energy is the extra energy generated above the plant's daily declared availability—so if Emera declares that the Brooklyn facility has availability of 20 MW, and NSPI dispatches the unit at 25 MW, there is a 5 MW payment for Incremental Energy.
- "Decremental Energy" has a fixed component [redacted]) and a variable component, which is similar to the Incremental Energy payment's variable component. Decremental Energy is the energy above the daily dispatch level requested by NSPI but below the daily declared maximum availability of the plant—

[23] See 2017 Annual Report, A-3.
[24] See 2017 Annual Report, A-3.

so if Emera declares that the Brooklyn facility has 20 MW of availability, and NSPI dispatches the plant to 9 MW, there is a payment for 11 MW of Decremental Energy.

- "Excess Energy" is paid a fixed rate of [redacted]. Excess Energy is the energy generated and supplied above the daily dispatch level requested by NSPI.

Given this complex series of cost streams, we reviewed NSPI's administration of the contract to determine if it was seeking to minimize cost under the PPA to FAM ratepayers. To do this, we reviewed NSPI's payments under the PPA for three years, focusing on the total amount of payments to the counterparty under the four available revenue streams. If NSPI were prudently managing the contract on a day-to-day basis, we estimated that "Capacity Energy" and "Decremental Energy" should make up the vast majority of payments under the contract. We confirmed that this was the case (see below).

Given that Capacity Energy payments are fixed under the contract, we expected that this category would constitute a significant portion of the total payments under the PPA. This was confirmed: these payments totaled about [redacted] of payments under the PPA over the three-year period.

That left three other cost streams to account for the remaining payments under the PPA. Incremental Energy should be minimal, as it is paid only if NSPI dispatches Brooklyn at a level that is higher than Brooklyn's declared availability. Given the high cost of this contract, we would expect such instances to be rare. We would also expect to see a large percentage of payments to be Decremental Energy, which are paid when NSPI dispatches Brooklyn at a level below its declared availability. We confirmed that this was true: Decremental Energy made up [redacted] of all payments during the three-year period, while Incremental Energy made up just [redacted].

The last revenue stream is one NSPI cannot control: Excess Energy is paid when Emera operates Brooklyn above its dispatched level. The rate paid for such energy is lower than the others, which is meant to create a disincentive for Emera to operate this way. We confirmed that Excess Energy payments totaled less than [redacted] of payments over the three-year period.

To sum up, [redacted] of all payments made by NSPI under the Brooklyn PPA were related to Capacity Energy and Decremental Energy, confirming that NSPI has been administering this contract prudently as it relates to NSPI's ability to dispatch the facility at a set level each day.

The second question we considered related to the Brooklyn PPA was whether NSPI had the opportunity to collect damages or even terminate the contract and failed to do so. The Brooklyn PPA contains a provision—section 9.1 Partial Termination—which states:

> 9.1 Partial Termination – In the event that the Seller's average annual Net Output in kW.h is significantly below the Energy Bid, [NSPI] may derate the value of the capacity received. In such a case, NSPC will notify the Seller that a refund is required.

"A significant reduction" is "deemed to have occurred if the average annual Net Output in kWh from the Seller's Facility for three consecutive Fiscal Years is less than [redacted] of the Energy Bid." "Net Output" is defined as

> [t]he power and energy output of the Facility after deducting Facility station service requirements. The Capacity Bid and the Energy Bid are based upon such Net Output.

"Energy Bid" is defined as

> [t]he annual amount of net electrical energy, in kilowatt hours, the Seller agrees to make available and dedicate to [NSPI] over the Term of the Contract. For this Contract, the Energy Bid shall be [redacted] as specified in the Project Proposal which is annexed to this Contract as Appendix A.

Moreover, the PPA states that

> [NSPI] may, at its option, terminate the Contract in the event of a second occurrence of energy production which is a 'significant reduction' as defined in Clause 9.1(a) from the Energy Bid.

Our review of Audit Period data shows that net generation from the Brooklyn facility was far below [redacted] of the Energy Bid of [redacted]. In 2016, Brooklyn provided just [redacted], and in 2017, provided just [redacted].[25] Moreover, in 2015, output from Brooklyn was [redacted].[26] However, it is our interpretation of the PPA that "Net Output" includes all "energy" under the PPA, which should include Capacity Energy. In other words, actual net generation is not the proper statistic to compare to the Energy Bid; rather, it is Emera's daily declared availability amount that matters. Thus, we requested Brooklyn's availability data during the Audit Period and determined that Brooklyn met its availability targets over the Audit Period. NSPI also provided data that showed Brooklyn met its availability targets under the PPA in 2014 and 2015 as well.

There is one additional point to note regarding the Brooklyn PPA. The previous fuel auditor included two recommendations regarding Brooklyn. We address NSPI's compliance with those recommendations below.

XI.B.1.b. Term RFPs

NSPI may regularly pursue RFPs for imported power across the New Brunswick-Nova Scotia intertie. These RFPs typically have a term of one month (though sometimes multiple months) and are typically issued one month in advance of power flow. During the Audit Period, NSPI issued a total of thirteen RFPs for purchased power. In all cases, the product sought was up to 100 MW of firm or non-firm energy, delivered to the New Brunswick-Nova Scotia Intertie. The RFPs offered bidders significant

[25] 2017 Q4 FAM Report, 9(3).

[26] 2016 Q4 FAM Report, 9(3).

flexibility in developing their bids, including the ability to bid on multiple product types, such as a 16-hour per day product for 5 days or for all 7 days of a given week. All 13 RFPs sought purchased power for delivery in the following month, and in some cases sought bids for multiple months. In all cases, NSPI's RFPs noted that "[o]ther products will be considered."

In all 13 RFPs, there are two important points. First, due to geographical realities, there are just [redacted] that can currently and realistically participate in NSPI's RFPs: [redacted] In just [redacted] of the 13 RFPs, NSPI invited all [redacted] to participate. In [redacted] RFPs, NSPI invited [redacted] bidders; in one other, it invited [redacted] Second, in all 13 cases, the winning bid(s) represented the lowest cost bids and were forecasted to provide a benefit to NSPI ratepayers. [redacted]

Figure XI-9. Summary of all Purchased Power RFPs for Audit Period

Date Issued	Product Sought	Term	Bids	Winners	Winning Price (US$/MWh)	Winning Volume (MWh)	Total Value (CAD$)	Estimated Savings (CAD$/MWh)
[redacted]								

Figure XI-9 shows that only [redacted] of the thirteen RFPs resulted in the successful procurement of imported purchased power. In the [redacted] unsuccessful RFPs, [redacted] saw no bids, while [redacted] others received bids that were not projected to provide economic benefits to NSPI's ratepayers.

Of the [redacted] potential counterparties that were invited to participate in NSPI's RFPs, [redacted]—participated in at least one RFP, while [redacted] won at least once. [redacted] while [redacted] Although invited to bid just [redacted]

Figure XI-10. Counterparties' Participation, Success in NSPI's Purchased Power RFPs

Counterparty	Number of Invites	Number of RFPs Bid	Number of RFPs Won
[redacted]			

NSPI's documentation of its purchased power RFPs is considerable. In all cases, the RFP is included, as well as all bids received, and a "recommendation memo" that contains a summary of the RFP and a recommendation on which bids, if any, to accept, and why. The memos also explain the impetus for the RFP, which is typically for economic purposes—i.e., to determine if there are any import power opportunities available. The memos include a detailed evaluation that considered the cost of the import versus the expected cost of internal generation, and an assessment of the risk of curtailment of the import.

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

27 In fact, for this particular month, NSPI did not issue a formal RFP, but instead called three parties—[redacted]—seeking offers for a September 2017 power purchase import. NSPI explains that "due to a late month change in fuel blending at the Lingan plant moving the generation cost from [redacted]…an import opportunity could be present."

28 [redacted] submitted a bid for a volume of energy in excess of NSPI's acceptable range.

XI.B.1.c. Short-Term Purchases

The Fuel Manual allows the NSPI Energy Marketers to make day-ahead and hour-ahead power purchases and sales.[29] Specifically, the Fuel Manual notes that NSPI's energy marketers will "closely monitor the internal and external power market conditions and the opportunity to import/export power economically."[30] The Fuel Manual requires the energy marketing team at NSPI to conform to NSPI's Risk Management Policy and Credit Policy, and to ensure that transactions are recorded—using recorded phone lines and instant messenger – and entered into NSPI's system.[31] Power transaction confirmations are stored electronically at NSPI.[32]

All of NSPI's import (and export) transactions—including its short-term transactions (e.g., day-ahead and hour-ahead) —involve some form of human decision making and intervention and are not automatic, per security-constrained economic commitment and dispatch.

There are two primary ways NSPI imports power on a day-ahead or real-time basis. One is through short-term import transactions sourced in New England, New Brunswick, or elsewhere. The second is through "joint dispatch" with NBP. We explain both below.

XI.B.1.c.i. Day-Ahead, Real-Time Imports from New Brunswick, New England, Quebec, and Newfoundland

Each day, NSPI's energy marketers look for opportunities to import power on a short-term basis—i.e., day-ahead or real-time. To do this, marketers compare two costs: the expected NSPI system cost to produce the next increment of power using its own generation (using GenCost and GenOps) and the expected total cost to procure that power from another source—the so-called import. Unfortunately, given the timing, most import transactions require estimates of multiple variables that may change such that although a transaction looks economically beneficial at the time the marketer executes it, it could end up being a money-losing transaction. (In our review of NSPI's import transactions during the Audit Period, we address this distinction in more detail.)

Figure XI-11 below summarizes NSPI's imports during the Audit Period. Notably, about 4.2% of NSPI's total system requirements (TSR) was provided by imported power for an average cost of [redacted]. In comparing Audit Period results to those of the previous period, this Audit Period's volume of import transactions is 16.5% higher than the previous Audit Period, while average import prices are down 17.4%.[33]

29 Fuel Manual Revision 10, section 13.1.

30 Fuel Manual Revision 10, Appendix R.

31 Fuel Manual Revision 10, section 13.1.

32 Fuel Manual Revision 10, section 13.1.

33 See 2014-2015 Audit Report, page X-2.

Figure XI-11. NSPI's Short-Term Imported Power Volume, Cost[34]

Year	Transaction Volume (MWh)	Volume as % of TSR	Total Cost	Cost per MWh
2016	[redacted]			
2017				
Total				

[redacted] We note that NSPI's newly-created affiliate—Nova Scotia Power Energy Marketing Inc.—has filed for approval at the US Federal Energy Regulatory Commission for market-based rate authority as of April 20, 2018,[35] which if approved, would allow NSPI to conduct power purchases and sales through its affiliate in the United States. Figure XI-12 shows all import transactions during the Audit Period, as broken down by counterparty.

Figure XI-12. NSPI's Short-Term Power Imports, by Counterparty[36]

	2016			2017		
Counterparty	Number of Transactions	Transaction Volume (MWh)	Average Price ($/MWh)	Number of Transactions	Transaction Volume (MWh)	Average Price ($/MWh)
[redacted]						

We sampled several of NSPI's import transactions during the Audit Period. Our goal was twofold. First, we wanted to determine if NSPI's marketers were entering into import transactions that were expected to be beneficial to its customers. We say "expected" because the import with New England

34 This table is inclusive of Cooperative Dispatch Agreement transactions with NB Power. NSPI Quarterly Report Q4 2017, 1(3) and 2(3).

35 Nova Scotia Power Energy Marketing Inc., "Application for Market-Based Rate Authority," Docket No. ER18-1404-000, April 20, 2018.

36 Quantities in Figure XI-12 may not add up to aggregate data provided in NSPI's quarterly FAM reports. This is largely due to transactions in which power does not flow (or is derated), resulting from actions system operators take to reduce or cut scheduled transactions because of insufficient transmission capability or for reliability reasons. Also, data in Figure XI-12 includes transmission losses, while data reported in the quarterly FAM reports does not.

involves estimates of NSPI's system marginal energy cost and ISO New England's expected energy prices—ISO New England requires all import transactions to be secured two hours ahead of energy flow. Second, given that the realized results may differ from the expected results at the time the transaction was executed, we wanted to know if, on net, NSPI's imports are resulting in savings to customers. Importantly, the first step here involves looking at the prudence of the marketers: given the information known at the time of the transaction, was the transaction expected to produce savings for ratepayers? And in the second step, we are testing the efficacy of NSPI's entire import approach—that is, not just whether marketers are prudent, but also whether NSPI's process—which must include estimation and, in some cases, the risk of price movements in the two hours from transaction to energy flow—is working.

We found that NSPI enters into import transactions for three reasons. Sometimes, imports are judged to be economic—we will call these "economic imports." Other times, imports are for reliability reasons—we will refer to these as "reliability imports." Economic import transactions are explicitly contemplated and addressed in the Fuel Manual. Imports for reliability purposes are not addressed explicitly in the Fuel Manual. (We provide a recommendation below regarding the codification and recordation of reliability imports.) A third category of imports are those NSPI engages in on behalf of and at the behest of PHP. Under the LRT, PHP can request NSPI to engage in import transactions on PHP's behalf.

XI.B.1.c.i.1. Economic Imports

We begin here with economic imports. It is important to note, first, that deciding to import power into Nova Scotia is not always based on a simple comparison of the cost of energy at the external source and the cost of producing the next increment of energy from NSPI's fleet. There are several other costs involved—some known, some estimated—that must be considered. The full cost of an import consists of (1) the price of the imported energy, (2) the transmission cost associated with the import, (3) the transmission losses charge, and, for ISO New England transactions, (4) New England tariff charges. Figure XI-13 summarizes the costs of New Brunswick transmission for imports of various classes and terms. In addition to these charges, all imports also must pay 3.3% in transmission losses for use of the New Brunswick transmission system.

Figure XI-13. Import-Related New Brunswick Transmission Charges ($CAD/MWh)

Service Increment	Transmission Class	Period	Transmission Cost ($CAD/MWh)	Ancillary Cost ($CAD/MWh)
Hourly	Non-Firm	On-Peak	$6.03	$1.15
Hourly	Non-Firm	Off-Peak	$2.86	$0.54
Daily	Firm	On-Peak	$4.02	$0.77
Daily	Non-Firm	On-Peak	$4.02	$0.77
Daily	Firm	Off-Peak	$2.86	$0.55
Daily	Non-Firm	Off-Peak	$2.86	$0.55
Weekly	Firm	Full Period	$2.87	$0.55
Weekly	Non-Firm	Full Period	$2.87	$0.55
Monthly	Firm	Full Period	$2.86	$0.55
Monthly	Non-Firm	Full Period	$2.86	$0.55
Yearly	Firm	Full Period	$2.86	$0.55

In addition to the charges related to use of the New Brunswick transmission system, imports from New England must also pay additional charges to ISO New England. Those charges are summarized in Figure XI-14.

Figure XI-14. ISO New England Charges for New England-Sources Imports ($USD/MWh)

Fee	Cost ($USD/MWh)
Schedule 1 for Through-and-Out Service	$0.27
Schedule 2	$0.38
Schedule 3	$0.40
OATT Schedule 1	$0.20
OATT Schedule 2 - Voltage Service	$0.13
OATT Schedule 8 - Through-and-Out Service	$11.79
GIS Costs	$0.01
Transmission Losses	–$0.18
External Inadvertent Cost Distribution	$0.02
Regulation	$0.18
Total	**$13.20**

In addition to the charges levied by ISO New England for all imports to Nova Scotia sourced in New England, NSPI must also pay a third-party marketer to actually execute the US-based transactions—NSPI currently does not have the requisite authority from the US Federal Energy Regulatory Commission to conduct such transactions on its own behalf. [redacted]

The charges above are non-trivial. For New Brunswick-sourced imports, the transmission fees and losses charges range between $3.41/MWh and $7.18/MWh (CAD). For New England-sourced imports, there is an additional charge of [redacted] for transmission, tariff, and marketing fees.

Therefore, for an import to be economic, it must be so including all of these various charges—in addition to the cost of the import itself.

All of the costs shown in Figure XI-13 and Figure XI-14, plus the transmission losses charges in New Brunswick and the energy marketing fee in New England, are known costs. They are added on top of the actual price for the import, which can be sources from another Canadian province or from New England. If the import is sourced from another province, its cost is known at the time of the transaction; if the import is from New England, the price must be estimated two hours in advance.

In reviewing a sample of NSPI's economic imports, we found that NSPI's marketers do use tools that allow them to compare the full cost of import transactions to the cost of incremental generation in Nova Scotia. This allows NSPI to use the best possible information in determining whether a potential import transaction is economic. For example, we verified that for ISO New England transactions, NSPI marketers can see the [redacted] that will apply to all such imports.

In our review of the economic imports, we found that NSPI does not retain the precise data that the trader who executed the import trade had at the time of the decision to transact. Two things were missing from NSPI's retained data: the estimated system marginal price in Nova Scotia in the hour of the transaction and the estimated price of the import. These two data points are necessary to make a complete judgement about the prudence of a given economic import transaction.[37] NSPI did provide what we deemed to be a reasonable proxy for the data that the trader would have seen at the time of the transaction. NSPI looked back at its logs and manually drew out the best estimate of the estimated system marginal price in Nova Scotia for the hour in which the import was to flow at the time the transaction was executed; reconstructing market prices (e.g., in ISO New England) was also feasible, given that these prices are transparent and publicly available. Using these reasonable proxies, we found that NSPI's traders' economic import transactions were almost all estimated to provide economic benefits to NSPI ratepayers. Nevertheless, our recommendation below is to track in every hour (1) the estimated system marginal price over the remaining hours of the day plus the next day, as well as (2) the estimated hourly price curve in ISO New England to allow for a complete analysis of NSPI's import transactions.

Our review of economic imports also demonstrated the complexity of transacting with ISO New England. Besides the fixed cost associated with the trades, we noted that the estimated market price can change rapidly between the time of the transaction's execution and the time of power flow—typically two hours. Moreover, NSPI also must deal with the threat of curtailment. NSPI could, for example, schedule an economic transaction but see its schedule cut and not actually receive any power. One way NSPI mitigates this risk is to enter into multi-hour import transactions, which have a reduced likelihood of curtailment. However, these multi-hour transactions carry more risk regarding price movements.

[37] We note that NSPI has not been asked for this data prior to our audit—i.e., for short-term import transactions, which is why we do not find that this lack of documentation is a concern—but rather is an enhancement to be applied going forward.

For our sample of economic import transactions, we found that NSPI accrued net benefits; in other words, overall the prices paid (including transmission and fees) for imported power were less than the actual system marginal price in the hour of flow. However, we also found that NSPI does not track the overall benefits of its import transactions as it does with New Brunswick "joint dispatch" transactions (see next subsection) and export transactions (see following section). This should be addressed. NSPI should show the Board and customers the benefits it accrues from all its import transactions. We include a recommendation to that end.

XI.B.1.c.i.2. Reliability Imports

In our review of import transaction samples, we identified several transactions that had particularly high prices—some of which were higher than NSPI's internal cost of generating the next increment—and through our discovery process, received information from NSPI regarding the system conditions at the time of those transactions that suggested that NSPI sought imports to shore up NSPI's supply during times of tight supply conditions in Nova Scotia. Those supply conditions were typically driven by high load, transmission or generation outages or de-ratings, or some combination of the three. NSPI provided sufficient evidence of the reliability concerns driving these transactions. NSPI also explained that all reliability import transactions are made at the request of the NSPSO, which is ultimately responsible for the reliable operation of the system in Nova Scotia.[38]

We note, however, that the Fuel Manual does not contain any reference to reliability imports. This should be addressed. Reliability-driven import transactions are common practice in the industry and are typically done at the behest of the system operator. However, it is important that the Fuel Manual acknowledge these types of import transactions, which often cost more and can increase FAM costs to be recovered from FAM customers. The Fuel Manual should make it clear that only the NSPSO is able to direct a reliability import transaction; this will prevent any potential ambiguities from arising for FERM employees, who will be limited to discretion in making economic imports only. Moreover, NSPI should begin tracking all reliability imports, identifying them accordingly, and recording the price paid as well as the system price to beat at the time of the transaction. This cost data will help inform future Nova Scotia investment decisions. If a particular investment was projected to reduce reliance on reliability import transactions, the historical cost related to reliability imports will be a good number to know and to compare to the cost of the investment.

XI.B.1.c.i.3. PHP Imports

Through transaction sampling, we discovered that, pursuant to the LRT, NSPI enters into a significant number of import transactions on behalf of PHP. Specifically, NSPI entered into import transactions [redacted]

[38] *Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules*, Chapter 3: Reliability Planning Requirements, Effective December 20, 2012, section 3.1.1.1, *available at* http://oasis.nspower.ca/site/media/oasis/Appendix%2025%20-%20Market%20Rules%20Ch%203.pdf.

Per the LRT, NSPI is to pass on 100% of these costs to PHP; FAM customers are to see no impact of these transactions. In responding to one of our data requests on this issue, however, NSPI determined that one of the import transactions we selected through sampling was one executed at the behest of PHP but billed to FAM customers.

After discovering this billing error, NSPI reviewed all its import transactions and discovered that NSPI had erroneously billed FAM customers for [redacted] of PHP import transactions, representing a total of [redacted] NSPI also discovered that it had erroneously billed PHP for import transactions done on behalf of FAM customers; this erroneous billing was for [redacted] of import transactions totaling [redacted]

The net cost effect of these erroneous billings was that NSPI overcharged FAM customers by [redacted] over the two-year Audit Period and undercharged PHP by that same amount. NSPI adequately explained how it would address this billing issue and also noted that it would address the issue in its month-end FAM report. Indeed, on June 8, 2018, PHP paid the [redacted] outstanding and NSPI credited FAM customers the same amount. NSPI also introduced a new control procedure that requires the Team Lead to check and sign off on all Allegro transactions against the import transaction database to ensure that the data are correct before being downloaded for PHP billing purposes.

We discuss the PHP import issue more in our final chapter.

XI.B.1.c.ii. Cooperative Dispatch with New Brunswick

For the entirety of the Audit Period, NSPI was party to a "Cooperative Dispatch Agreement" with NBP. This arrangement, which began as a pilot program in 2014, was extended (as recently as December 2016) through the end of the Audit Period (December 31, 2017). Pursuant to the agreement, the term automatically extends for an additional one-year period, unless either NSPI or NB Power terminates the agreement.

The agreement provides the mechanism for NSPI and NBP to buy and sell available energy and/or operating reserves from the other. The agreement states that when one party has available energy—that is, energy in excess of that party's load obligations—it may pursue sales of that energy to the other party when it is economic to do so. For example, assume NBP has an extra 50 MW of energy available above and beyond its needs to supply NBP's load, and assume that power has a cost of $25.00/MWh. Under the Cooperative Dispatch Agreement, if the cost to serve NSPI's load is, say, $45.00/MWh, the parties can pursue a sale of NBP's excess energy to NSPI—this will result in overall ratepayer savings.

Drilling deeper, the agreement calls for transactions across a variety of energy products and specifies the costs to be included and the method for sharing the savings. [redacted] Transmission and ancillary services costs are not included in the determination of whether to enter into a cooperative dispatch transaction, but are required to be paid by the applicable party. In all cases, transactions are contingent on available transmission capacity between the two provinces. Also, in all cases, settlement of the transactions is done based on 50-50 sharing of the net benefits. So if a transaction results in savings of $1,000, $500 goes to both NSPI and NBP, regardless of which party was the buyer and which was the seller.

The products—which can be real-time, day-ahead, weekly, or monthly—include the following: (1) bilateral energy; (2) excess hydro energy; (3) excess wind energy; (4) reserve-enabled bilateral energy, in which the purchasing party assumes all or part of the selling party's operating reserve obligation, enabling the selling party to have available energy for sale; and (5) operating reserve. Notably, excess hydro and excess wind transactions are allowed under the agreement if the difference between the prices in the two provinces is greater than $0/MWh. However, for bilateral energy transactions, the transactions are allowed only if the difference between the prices in the two provinces is [redacted] or greater.

The agreement also establishes committees with representatives from each party. The Operating Committee, for example, meets at least every quarter "for the purpose of further exploring opportunities to maximize the potential for the purchase and sale of Available Energy and Available Reserve and their associated products and services between the parties."

There are several points to underscore, each of which limits the effectiveness of the Cooperative Dispatch Agreement. First, the entirety of the Cooperative Dispatch Agreement and its execution by NSPI and NBP is done voluntarily and through bilateral communications between NSPI and NBP marketers. Nothing about this agreement or its execution is automated: every day, NSPI and NBP look for opportunities to share energy or operating reserves that would result in overall cost savings. If those opportunities arise, the parties may pursue them by directly communicating and transacting. Not every possible economic transaction will be identified or pursued, given the manual process called for under the Cooperative Dispatch Agreement. NSPI is not *required* by regulation or law to pursue every possible economic transaction, and as such, it may only be encouraged to pursue such transactions and to report on their results. Moreover, in all transactions, a willing counterparty is needed, and it is up to NBP to voluntarily agree to each transaction. Another limiting factor is the [redacted] threshold required for non-wind, non-hydro energy transactions, which further limits the number of transactions—and thus savings—that will occur. Last, the fact that NSPI has limited visibility into NBP's system—and vice versa—means that there is a fundamental lack of precision in the identification of all economic transaction opportunities. NSPI confirmed that opportunities are identified through marketer-to-marketer communications between NSPI and NBP. This approach is in contrast to that of a market-based power pool, which commits and dispatches units across the regional footprint in a manner that solves for the least cost solution to provide energy and ancillary services, while respecting system security and reliability constraints. The latter identifies and captures efficiencies automatically; the former does not.

NSPI tracks and reports on all its transactional activity related to the Cooperative Dispatch Agreement with NBP. Figure XI-15 below shows the total savings and total MWh of transactions over the two-year Audit Period.

Figure XI-15. NSPI's Savings, Transactional Volumes from Cooperative Dispatch Agreement

Year	Savings	Transaction Volume (MWh)
2016	$2,139,727	263,636
2017	$1,054,301	126,220
Total	**$3,194,028**	**389,856**

Figure XI-15 shows that the Cooperative Dispatch Agreement's impact on NSPI's FAM customers has been positive, saving about $3.2 million over the Audit Period. Nevertheless, it is somewhat concerning to see both the transactional volume and NSPI savings drop so significantly from 2016 to 2017. Moreover, according to the previous auditor, the cooperative dispatch of the two systems was forecasted to save between $5 million and $20 million per year between the two parties, meaning NSPI's 50% share would range between $2.5 million and $10 million per year.[39] We provide a recommendation in the Economic Commitment and Dispatch chapter that attempts to increase the likelihood of achieving greater ratepayer savings.

XI.B.2. **Power Exports**

In addition to importing power, each day, NSPI's energy marketers look for opportunities to export power on a short-term basis—i.e., day-ahead or real-time. In general, these export opportunities fall into two categories, but both categories are based on economics. One set of transactions is related to instances where the price for power elsewhere is higher, net of all transmission and tariff fees, than the cost to produce power in Nova Scotia. A second set involves periods of high wind output, whereby the Nova Scotia system has excess energy. In these cases, NSPI marketers look to sell this excess energy—in some cases renewable energy from South Canoe—into other jurisdictions in order to get some revenue, as an alternative to curtailment.

To determine whether a potential export is economic, marketers compare NSPI's system cost to produce the next increment of power using its own generation (using its GenCost program) with the expected revenue of the export sale. As with imports, export transactions with New England must be executed at least two hours in advance, meaning that variables that may change in such a way that although a transaction looks economically beneficial at the time the marketer executes it, it could end up being a money-losing transaction.

Figure XI-16 below summarizes NSPI's exports during the Audit Period. NSPI exported an amount that corresponded to less than 1% of its total system requirements during the Audit Period.

[39] Liberty Audit Report for 2014-2015, page IX-2.

Figure XI-16. NSPI's Short-Term Exported Power Volume, Cost[40]

Year	Volume (MWh)	Volume as % of TSR	Total Revenue	Total Cost	Gain (Loss)
2016	[redacted]				
2017					

As shown in Figure XI-16, the volume of exports greatly increased in 2017 compared with the year prior. This was driven by increased exports of excess wind generation during 2017. Until December 22, 2016, NSPI classified all exports of wind power as a single aggregate source of all wind resources—a sort of "overgeneration of wind" category. However, beginning on December 22, 2016, NSPI began differentiating South Canoe from the other wind farms. NSPI claims that it exports power from South Canoe to ISO New England when it is economic to do so. NSPI does so by using its affiliate—Emera Energy—to conduct the sales of excess energy (and associated renewable energy credits) from South Canoe into ISO New England. [redacted] In choosing [redacted], NSPI selected the lowest cost offer.)

Unlike for power imports, NSPI does track the overall net benefits of its power exports over the Audit Period. As is shown in Figure XI-16 above, exports of power resulted in a net benefit of about [redacted] to NSPI customers in 2016; however, in 2017, power exports *lost* money for NSPI and its ratepayers. Specifically, NSPI lost about [redacted] for every MWh exported from Nova Scotia. The extent of this result was magnified by the fact that NSPI exported about twice as much power as it had in its FAM Budget—about [redacted] versus a budgeted amount of [redacted][41] We probed this issue with NSPI and discovered that the data in Figure XI-16 do not include all revenues earned for the sale of Renewable Energy Certificates (RECs) associated with wind exports to ISO New England. The majority of NSPI's exports during 2017 were wind exports into New England; such sales generate Massachusetts Class I RECs. However, to realize revenue from the sale of those RECs, NSPI must first accrue them and then sell them. Moreover, sales of RECs are best done in standard [redacted] blocks to maximize the price per REC earned in the sale. Collectively, these factors create a lag in the time NSPI exports wind generation to New England to the time NSPI recovers the revenue from REC sales. Given that the economics of the exports are often dependent on REC revenue, this can create the illusion of uneconomic transactions.

That said, over time, we would expect this effect to lessen: for example, we would expect that REC revenues recovered in 2018 that are related to exported generation from 2017 would artificially inflate the

[40] This table is inclusive of Cooperative Dispatch Agreement transactions with NBP.

[41] Tab 7 (3) from FAM Quarterly Report Q4 2017.

value of 2018 exports; this artificial inflation would offset the lag in recovering REC revenues associated with 2018 exports. Here, since 2017 is the first year in which NSPI exported wind energy in larger quantities, we see only the effect of the lag, which would lead to an understating of the benefits of exports during the year. That understatement can be significant: Massachusetts Class I RECs average about [redacted] over the Audit Period. At that price NSPI's 2017 South Canoe exports will have generated over [redacted] in revenue for REC revenues alone, more than offsetting the recorded loss on 2017 export transactions.

[redacted]

Figure XI-17. NSPI's Power Exports, by Listed Counterparty[42]

	2016			2017		
Counterparty	Number of Transactions	Volume (MWh)	Average Price ($/MWh)	Number of Transactions	Volume (MWh)	Average Price ($/MWh)
[redacted]						

As with imports, we sampled several of NSPI's export transactions during the Audit Period. Our goal was to determine if NSPI's marketers were entering into export transactions that were expected to be beneficial to its customers. We say "expected" because the export with New England involve estimates of NSPI's system marginal energy cost, ISO New England's expected energy prices—ISO New England requires all import transactions to be secured two hours ahead of energy flow—and also Massachusetts Class 1 REC prices, which also must be estimated. Second, given that the realized results may differ from the expected results at the time the transaction was executed, we wanted to know if, on net, NSPI's exports are resulting in savings to customers. Importantly, the first step here involves looking at the prudence of the marketers: given the information known at the time of the transaction, was the transaction expected to produce savings for ratepayers? And in the second step, we are testing the efficacy of NSPI's entire export approach—that is, not just whether marketers are prudent, but also whether NSPI's process—which must include estimation and, in some cases, the risk of price movements in the two hours from transaction to energy flow—is working.

[42] Quantities in Figure XI-17 may not add up to aggregate data provided in NSPI's quarterly FAM reports. This is due largely to transactions in which power does not flow (or is de-rated) as a result of actions by system operators to reduce or cut scheduled transactions because of insufficient transmission capability or for reliability reasons. Also, data in Figure XI-17 include REC sales as MWh amounts, while the quarterly FAM reports do not.

The transactions we sampled demonstrated that NSPI's sampled exports were expected to produce net benefits, and in the vast majority of cases did so. This is a confirmation of prudent decision making and reasonable forecasting of expected ISO New England market prices and REC prices.

Additionally, we found NSPI's system interface for determining whether a transaction is forecasted to be economic to be clear and straightforward. It shows the recent and forecasted prices in ISO New England, as well as the forecasted price for renewable energy credits in New England. The expected REC prices were reasonable, averaging about [redacted] and ranging between [redacted] and [redacted]. In other words, for a given hour, NSPI can determine the total expected revenue it would receive for an export sale of wind power into New England. Next, the cost of the needed transmission to bring about the transaction is included, which can be netted against the expected revenues. Last, the marginal system cost in Nova Scotia is shown. If the expected revenues from the sale of power and RECs in New England, net of transmission costs, exceeds the marginal system cost in Nova Scotia, the export transaction will look economic, and NSPI may pursue such a transaction.

The nature of exports to New England involves a time risk for both the power revenue and the REC revenue. For power, there is a two-hour delay between transaction execution and power flow, so the actual price of power in the hour in which power flows may not equal NSPI's forecasted New England power price. RECs, meanwhile, are typically sold in blocks of [redacted], which means they are not sold right away, and there is a risk that the actual price received for RECs may be less than what was forecasted by NSPI at the time of the transaction. These timing risks are an inherent part of transactions with New England. Also, [redacted] as agent for NSPI in the New England markets, charges a flat fee of [redacted] for all renewable export transactions. It is not clear to us that this cost—albeit modest—was included in the trader's interface. On this point, we think NSPI should include this cost in its model interface that traders use, so that they see the full cost of the exports. Moreover, we note that NSPI has begun a process to develop its own affiliate in New England to conduct these (and other import/export) transactions in the future, which could result in savings for NSPI ratepayers.

XI.B.3. Liberty's 2014–2015 Recommendations

In its last report as fuel auditor, Liberty provided two recommendations related to purchased power and sales;[43] moreover, Liberty included two recommendations related to the Brooklyn PPA, which were contained in the chapter on FAM accounting.[44] We address NSPI's compliance with those four recommendations here.

The first recommendation was: "Management should extend [NSPI]'s PLEXOS modeling capability into New Brunswick." NSPI agreed with this recommendation but stated that due to "the complexity and potential for mismatch between attempting to model the New Brunswick system, as compared to [NBP's] actual dispatch, it is not practical to include New Brunswick's system in [NSPI]'s regular forecasting of

[43] Liberty's 2014-2015 Audit Report, pages X-18 to X-19.

[44] Liberty's 2014-2015 Audit Report, pages XI-13 to XI-14.

its dispatch/fuel costs."[45] Instead, NSPI has focused on "joint modeling of a combined NS/NB system in PLEXOS for joint dispatch" and committed to "continue to work with [NBP] to collaborate on future joint PLEXOS modeling."[46] We find NSPI's response regarding the modelling of New Brunswick's system for the purpose of better planning NSPI's fuel forecasts to be reasonable; the benefit of such an exercise may not be worth the time and cost. However, we do see significant value in developing a true coordinated dispatch with New Brunswick—that is, not a system like the current one, which relies on traders to make decisions, but rather a co-optimized, model-based approach that would identify and execute *all* feasible economic trades with New Brunswick, not just those that benefit from the successful interaction of the human staffs at NSPI and New Brunswick Power Corporation. Done well, this coordinated dispatch would help NSPI increase the value of its contractual arrangements with New Brunswick. That topic is addressed in the Economic Commitment and Dispatch chapter, where we provide our recommendation on this matter.

The second auditor recommendation was: "Management should develop a strategy for increasing access to power resources from the west, and report to the NSUARB." NSPI stated that it "accepts" this recommendation, noting an upcoming study—the "Regional Electricity Cooperation and Strategic Infrastructure," or RECSI study—which would "identify, study and seek regional consensus on the most promising electricity infrastructure projects in the Atlantic provinces that support the transition to lower GHG emissions, including examining how to replace existing coal-fired generating capacity in Nova Scotia and New Brunswick through regional infrastructure solutions."[47] The RECSI study was scheduled to be completed by January 31, 2018; however, as of April 13, 2018, the study was still not completed, and we did not receive the study between that date and the date of this report. NSPI also explains that once the report is finished, there are additional steps that will occur: "development of a Summary for Policy Makers" and "deliberations" by "committees and the Provincial and Federal Governments." NSPI's response to this recommendation is not unreasonable, as regional solutions will require coordination and cooperation from external entities, and perhaps that coordination is best done through the RECSI process. However, we are not convinced that NSPI's efforts to expand its access to power and/or natural gas sources from the west should be limited by the timing and content of the RECSI study and accompanying processes. That is why, in the Power Plant Performance Chapter, we recommend a more robust and regular IRP process in which NSPI assesses all its options—including infrastructure projects that expand access to the west—for their costs and benefits on a level playing field. Our recommendation can be found in that chapter.

The previous fuel auditor had two additional recommendations that we address here, as they are related to the Brooklyn PPA: "Conduct a detailed review of Brooklyn Energy costs as allowed under the current agreement, covering the period of July 2013 through year end December 2015;" and "Develop a formal plan to review Brooklyn Energy costs for 2016 and beyond, as the current contract agreement

45 FAM Audit Action Plan, January 31, 2017, page 16; see also FAM Audit Action Plan, July 31, 2017, page 19.

46 FAM Audit Action Plan, July 31, 2017, page 18.

47 FAM Audit Action Plan, January 31, 2017, page 16–17.

provides [NSPI] with the opportunity to request access to pertinent and relevant records to substantiate such charges."

NSPI agreed with both recommendations.[48] Regarding the first, NSPI's internal audit team completed a review of Brooklyn Power costs for the period July 2013 to December 2015. [redacted] We find NSPI's internal audit to be sufficiently responsive to Liberty's recommendation, and we encourage NSPI to update the Board upon completion of the process. We include a related recommendation below.

On the second recommendation, for a forward-looking review of Brooklyn costs, NSPI stated that it would develop a plan "after the Internal Audit work is completed and recommendations for ongoing assessments are made" and that NSPI would "keep the Board apprised of its progress on this initiative through the established FAM Audit Action Plan process."[49] In its report, the internal audit team recommended that:

> [redacted]

NSPI informed us that FERM is still reviewing the results of the audit engagement and that once that is complete, it will formalize a process. NSPI estimates that the cycle of review performed by management will be every two years. It is reasonable for NSPI to have waited for its internal audit team to complete its work before finalizing a formal plan for reviewing future Brooklyn costs. We underscore the

48 NSPI FAM Audit Action Plan, January 31, 2017, pages 17–18.

49 FAM Audit Action Plan, July 31, 2017, page 18.

importance of NSPI auditing these costs every year, especially given the results of its internal audit on this topic to date. And we find NSPI's internal audit recommendations to be sound and encourage NSPI to incorporate them into their formalized process or explain why they are impractical. We include a recommendation to this effect.

XI.C. Conclusions

Conclusion XI-1: Third-party power serving NSPI's customers continues to grow, from [redacted] in 2013 to [redacted] in 2017. Most of the third-party generation providing power to NSPI customers are policy-driven renewable resources, such as COMFIT and independent wind and other renewable sources, which often have high associated contractual costs.

Conclusion XI-2: Below-budget performance by COMFIT resources also helped keep FAM costs lower than they otherwise would have been during the Audit Period. Specifically, in 2017, NSPI ratepayers saw savings of over $10 million thanks to the lower-than-budgeted COMFIT output, assuming the replacement power was priced at the system average of [redacted]. Meanwhile, in 2016, decreased COMFIT production saved customers about $16.7 million.

Conclusion XI-3: Cape Sharp Tidal's operational issues—which have delayed the facility from contributing substantive energy production—helped keep costs down for NSPI ratepayers. Cape Sharp's per MWh PPA price is very high: $530.00/MWh for the first 16,640 MWh and $420.00/MWh for any energy provided beyond that amount. Specifically, in 2017, the FAM budget called for more than [redacted] to be provided by Cape Sharp at a total cost of over $12 million. With the 2017 average dollar-per-megawatt-hour FAM cost of [redacted], replacing those [redacted] with system energy meant a savings of over $11 million for FAM customers in 2017 alone; in 2016, Cape Sharp's under-budget performance saved customers approximately $4.4 million, based on replacement energy at the 2016 average system cost of [redacted].

Conclusion XI-4: NSPI's power imports were constrained by the intertie between Nova Scotia and New Brunswick, which limits the amount of power that can flow from outside sources to Nova Scotia. This limitation prevents further integration between Nova Scotia and its neighbors, limiting the economic benefits that could be enjoyed through additional system integration and import/export power transactions.

Conclusion XI-5: Going forward, NSPI's intertie capability will directly impact fuel costs in future FAM audits. As a result, we believe that NSPI's resource planning process—which we address in the Power Plant Performance Chapter—should be improved in a number of areas, including considering all resource alternatives, including transmission investments and expanding intertie capability, such as increasing the capacity and [redacted] of the New Brunswick-Nova Scotia intertie. The arrival and energization of the Maritime Link will only increase the importance of this, as new power flows from Newfoundland and Labrador will potentially seek to access the New Brunswick and New England markets via the NSPI system.

Conclusion XI-6: The Brooklyn biomass facility is an expensive source of energy for ratepayers that is the product of a PPA signed in 1992. Given its high cost, it is not clear to us that, if proposed today, the contract would be in the interest of FAM customers—let alone the fact that the contract now resides with NSPI's parent, Emera. Nevertheless, NSPI appropriately administered the contract during the Audit Period by minimizing the output of the facility—thereby minimizing the cost borne by NSPI ratepayers. Moreover, NSPI monitored the performance of the counterparty under the PPA, ensuring that the counterparty met its availability targets specified in the PPA.

Conclusion XI-7: NSPI adequately addressed the previous fuel auditor's recommendation to conduct an audit of the Brooklyn PPA. NSPI's internal audit review of the Brooklyn PPA costs charged by Emera under the PPA revealed some discrepancies that have led to additional scrutiny and coordination with Emera to correct any inaccurate billing over the 2013–2015 period. On completion of this process, NSPI should update the Board regarding billing adjustments and FAM customer impacts. (Recommendation)

Conclusion XI-8: NSPI has adequately addressed the previous fuel auditor's recommendation to develop a formal plan to make ongoing assessments of the Brooklyn PPA, but more remains to be done. With the internal audit process—including discussions with the PPA counterparty—ongoing, it is appropriate to formalize the plan once the proceedings have concluded. However, NSPI should make sure that its formalized plan includes a review of these costs in all years going forward from 2015, since the billing discrepancies identified in NSPI's internal audit are likely to have repeated themselves since then. NSPI's internal audit recommendations regarding the design of this formalized process are sound and should be included in NSPI's final design. (Recommendation)

Conclusion XI-9: NSPI's term RFPs are generally sound and well run. The RFPs selected the lowest cost offer(s) in almost all instances, and where the chosen offers were not lowest cost, the choice was adequately explained. In all cases, only offers projected to be economic were selected. The RFPs are limited by the number of potential counterparties and available transmission capability.

Conclusion XI-10: In rare instances, NSPI's RFP evaluations may not always be fully transparent. For example, in [redacted] cheaper than the next closest bid—in favor of a higher priced bid. While that higher priced bid was [redacted] that would provide NSPI with additional flexibility to its solid fuel fleet the rest of the year, it is not obvious to us how NSPI judges bids across these various categories of costs and benefits. (Recommendation)

Conclusion XI-11: In many cases, not all [redacted] counterparties were invited to the RFPs. (Recommendation)

Conclusion XI-12: NSPI is considering curtailment risk in its RFP process. For example, in three separate RFPs, NSPI ran a sensitivity of 10% curtailment, another with 25% curtailment, and a third with a qualitative assessment of the impact of curtailment on the economics of the bid.

Conclusion XI-13: [redacted]

[redacted] (Recommendation)

Conclusion XI-14: Relatedly, it is not clear from the Fuel Manual or the results of NSPI's import RFPs whether bids are required [redacted]

Conclusion XI-15: Short-term economic import transactions were generally forecasted to provide net benefits to customers, given the reasonable proxy data provided by NSPI. The short-term import economic transactions we sampled also provided actual net benefits to ratepayers. That said, NSPI could improve its process by tracking and maintaining records of exactly what price (and estimated price) and other cost data the trader relied on at the time of the transaction. NSPI should maintain these records for all import transactions, whether economic, for reliability, or for PHP, and report these data as it already does for export transactions. (Recommendation)

Conclusion XI-16: NSPI also conducts imports for reliability reasons; however, it does not actually distinguish reliability imports from economic imports, nor does the Fuel Manual contain any reference to or definition of a reliability import transaction. Given the significant numbers of reliability transactions we observed during the Audit Period, it is clear NSPI is relying on import transactions for reliability purposes in certain hours. NSPI should codify its use of reliability import transactions in its Fuel Manual; make clear that only the NSPSO can direct a reliability import; and initiate a tracking system whereby all import transactions are logged as "reliability," "economic," or "for Port Hawkesbury Paper." (Recommendation)

Conclusion XI-17: NSPI also conducts import transactions on behalf of PHP under the terms of the LRT. During the Audit Period, NSPI erroneously billed some PHP import transactions to FAM customers and also erroneously billed some FAM customer import transactions to PHP. The total cost impact of these errors was a [redacted] overcharge of FAM customers and a [redacted] undercharge of PHP. NSPI has resolved this billing error by billing and receiving payment from PHP and crediting FAM customers for the [redacted]

Conclusion XI-18: Our sample of NSPI's power exports was generally forecasted to provide benefits for FAM customers. Actual benefits are difficult to determine, due to the time lag associated with the realization of REC revenues.

Conclusion XI-19: NSPI's Cooperative Dispatch Agreement provided benefits to NSPI ratepayers during the Audit Period. That said, its structure will inherently limit the potential benefits that could accrue. It relies on voluntary decisions by NSPI *and* NBP and is dependent on human communication and identification of opportunities. It is also limited by (1) NSPI's lack of access to NBP's system, and vice versa, and (2) from administrative hurdles such as the [redacted] threshold on [redacted] energy transactions. Given the essential nature of the NSPI-New Brunswick intertie to NSPI's access to other power suppliers, NSPI should seek to continuously improve the content, impact, and execution of cooperative dispatch with NB Power. Our recommendation on this matter is found in the Economic Commitment and Dispatch Chapter.

Conclusion XI-20: Relatedly, NSPI has provided a reasonable explanation in response to the previous fuel auditor's recommendation regarding extending PLEXOS modelling into New Brunswick, as it relates to forecasting NSPI's fuel costs. However, we see significant potential benefits to a true coordinated dispatch with New Brunswick—that is, a co-optimized model-based approach that would identify and execute all feasible economic trades. This topic is discussed more in the Economic Commitment and Dispatch Chapter, which is also where we provide our recommendation.

Conclusion XI-21: NSPI's response to the previous fuel auditor's recommendation for increasing access to power resources from the west was not unreasonable. The RECSI study could represent a good first step toward coordination and collaboration between relevant entities on regional infrastructure investments and supply arrangements. However, NSPI's efforts to expand its access to natural gas and power sources to its west should not be limited to the RECSI study and process. NSPI's IRP planning should consider investments that could expand such access, including transmission and natural gas investments. Our recommendation on this issue is found in the Power Plant Performance Chapter.

Conclusion XI-22: While we did not review the potential associated costs, NSPI's pending market-based rate authority application at the Federal Energy Regulatory Commission to allow it to transact for imported and exported power in the United States through its newly created affiliate (Nova Scotia Power Energy Marketing Inc.) would avoid transaction fees on import and export transactions: [redacted]

XI.D. Recommendations

Recommendation XI-1: NSPI should invite all realistic counterparties to respond to its RFPs. Even if there is a lower probability the counterparty will reply, it is a low-cost step. It helps maintain a relationship with a potential future trading partner, especially as available transmission changes over time. It also keeps up competitive pressure on other trading counterparties.

Recommendation XI-2: NSPI should seek to use price-only evaluations whenever possible in its RFPs, and to quantify all costs, such as curtailment risk, as well as benefits, [redacted]

Recommendation XI-3: NSPI should be more consistent in selecting and explaining the "price to beat" in its RFPs, clarifying whether bids must beat the [redacted]

Recommendation XI-4: NSPI should finalize its plan to review Brooklyn PPA costs regularly and should include [redacted]. That plan should also ensure that costs in all years since 2015 are reviewed.

Recommendation XI-5: NSPI should introduce the capability to label each import transaction as "economic," "reliability," or "for PHP" and should label all import transactions going forward.

Recommendation XI-6: For all import and export transactions, NSPI should record and maintain records of exactly what (1) price (and/or estimated price) the trader expected for the import or export transaction; (2) the NSPI system marginal price (or estimated NSPI system marginal price) to beat for the import or export transaction; and (3) all other cost or estimated cost data the trader relied on at the time of the transaction, including any transmission costs, tariff fees, REC prices, or transaction fees. NSPI should execute this recommendation for all imports, whether economic, for reliability, or for PHP, as well as all exports.

Recommendation XI-7: NSPI should track and report on the actual costs and benefits of all import transactions, as it already does for all export transactions. This reporting should distinguish among economic imports, reliability imports, and imports for PHP.

XII. Hedging

XII.A. Background

To fuel its generating units, NSPI must buy fuel on the open market, which exposes NSPI—and FAM customers—to price risk. If fuel prices rise, NSPI must pay more (and charge FAM customers more) for fuel; if fuel prices fall, NSPI and FAM customers pay less. Volatility in fuel prices can lead to volatility in FAM customer rates. Hedging is a process that reduces FAM customers' exposure to changing fuel prices and thus can moderate rate volatility. Through fixed-price physical contracts or financial contracts that gain in value when market prices for fuel rise and lose value when prices fall, NSPI can counteract or "hedge" the higher (or lower) market prices that it must pay for fuel. Hedging is not seeking to reduce cost; rather, it is seeking to lower risk.

Until the end of 2016, NSPI's approach to hedging varied by fuel,[1] and NSPI's hedging activities and the prudence of those activities was reviewed as part of the FAM audit process.[2] Beginning in 2017, NSPI's approach to hedging changed. The impetus for this change was Nova Scotia legislature's EPIA.[3] The EPIA required NSPI to submit a Fuel Stability Plan that was designed to stabilize rates throughout the three-year RSP to the Board for approval. This plan was required to include "a description of any hedging strategies or mechanisms proposed to be used by Nova Scotia Power to manage fuel costs during the Rate Stability Period."[4] In other words, as noted by the Board in the Rate Stability Order, "[T]he EPIA requires the Board to give advance approval of the hedging strategy, thus reducing any risk to NSPI shareholders that there may be a finding of imprudence."[5]

Given that the Audit Period includes the final year of NSPI's traditional approach to hedging and the first year of NSPI's new approach to hedging, we address both periods in this chapter. However, as we explain below, to be ready for the Rate Stability Period (RSP), NSPI transacted throughout 2016. Moreover, given this significant change in approach, we have isolated hedging as its own chapter, which represents a break from the previous FAM audits that addressed hedging in the appropriate fuel chapters (i.e., hedging of coal was addressed in the chapter on coal procurement). Our purpose in this chapter is not to re-evaluate the merits of the Rate Stability Decision or NSPI's new hedging program, which the Board approved. Rather, our purpose is to explain how NSPI approached hedging in the two periods—that is, in 2016 (pre-RSP) and 2017 (RSP)—and to assess the results. Before we turn to our findings,

1 NSPI, "Fuel Hedging Plan," Version 1.4, September 2016, Appendix A.

2 Nova Scotia Utility and Review Board, "Decision," 2016 NSUARB 129 M07348 ("Rate Stability Decision"), paragraph 52.

3 Nova Scotia Legislature, "Electricity Plan Implementation (2015) Act," December 18, 2015, *available at* https://nslegislature.ca/legc/bills/62nd_2nd/3rd_read/b141.htm.

4 EPIA, 4(d).

5 Rate Stability Decision, paragraph 53.

conclusions, and recommendations, we begin with a primer on NSPI's two approaches to hedging during the Audit Period.

XII.A.1. Summary of NSPI's Hedging Programs during the Audit Period

XII.A.1.a. Hedging in the Pre-Rate Stability Period

The hedging program in the period preceding the RSP applied different strategies to each fuel. For solid fuel, NSPI employed a time-based strategy, using fixed-price physical fuel and transportation contracts to hedge its exposure to changes in price; NSPI hedged up to 30% of its short-term exposure, and 30%–50% of both its medium- and long-term exposure. For natural gas, NSPI had no specific volume targets, but instead used a computer-based model to calculate "value at risk" (VaR) which is an industry standard risk measurement metric that calculates the dollars—or value at risk—given a particular holding period at a particular probability of loss. Based on VaR results, NSPI would assess its hedged positions and need for adjustments. For electricity, NSPI hedged on an ad hoc basis with no specific targets; for heavy fuel oil, NSPI used fixed price contracts and physical storage as a hedge and aimed to have enough oil on site to meet peak demand in winter months. Figure XII-1 provides additional detail regarding NSPI's pre-RSP hedging approach.

Figure XII-1. Pre-Rate Stability Period Hedging Strategies by Fuel Type[6]

Fuel	Strategy Applied	Hedge Limits/Targets	Benefits of Strategy	Disadvantages of Strategy
Solid Fuel	Time based	Long term (>4 years): 30%-50% Medium term (1-4 years): 30%-50% Short term (<1 year): 0%-30%	Easy to implement. Guarantees a targeted hedged position. Implicitly assumes buying over time will produce an 'average' price.	No recognition of associated risk. No early warning signal if the upside or downside risk increases. Works best when market rising.
Natural Gas	VaR based	No specific targets, volumes depend on market conditions	"Risk" management; not price management. Used by the counterparties to the hedgers. Performance geared to avoiding undesirable risks.	Complex to implement relying on quantitative and statistical techniques. More difficult to explain.
Electric Imports	Short term/ ad hoc	No specific targets/limits	Similar to a time-based strategy	
Heavy Fuel Oil	Physical storage only	Inventory levels targeted to meet seasonal winter peaks	Similar to a time-based strategy	

6 Fuel Hedging Plan, September 2016, Appendix A.

XII.A.1.b. Hedging in the Rate Stability Period

NSPI's Fuel Hedging Plan[7] was developed in response to the EPIA; stakeholders and the Board vetted it before eventually approving it in 2016.[8] The Fuel Hedging Plan will apply to all years of the RSP—that is, through the end of 2019.

NSPI's approach to fuel hedging in the RSP is to hedge between [redacted] of its exposure to each fuel for each year of the RSP. This target percentage range is subject to available liquidity in suitable hedging products. Importantly, NSPI aimed to meet these targets for all years of the RSP by the end of 2016.[9] This meant that NSPI had to begin procuring hedges for 2017, 2018, and 2019 during 2016—even before the Board approved the Fuel Hedging Plan. (We discuss this issue below.) The Fuel Hedging Plan also calls for "quarterly rebalancing" of NSPI's hedged position. Below, we provide several important aspects of NSPI's approach to fuel hedging during the RSP.

XII.A.1.b.i. Permitted Financial Products and Trade Types

Subject to approval of the Fuel Strategy Table, the general types of financial contracts permitted by the Fuel Hedging Plan are presented in Figure XII-2 below, which also explains the characteristics of each financial instrument.

7 Fuel Hedging Plan, Version 1.4, September 2016.

8 Nova Scotia Utility and Review Board, "Order," M07348, November 15, 2016.

9 Fuel Hedging Plan, page 8.

Figure XII-2. Permitted Financial Contract Types[10]

Financial Hedge Instrument	Definition	Trading	NSPI Permitted Settlement
Futures	A futures contract *obligates* the buyer (seller) to purchase (sell) an asset at a particular time in the future at a particular price.	Standardized contract – trades on an exchange	Cash
Forwards	A customized contract obligating the buyer (seller) to purchase (sell) an asset at a particular time in the future at a particular price.	Non-standard contract – Over-the-Counter (OTC), non-exchange traded	Cash or Physical Delivery
Swaps[11]	A derivative contract where the two sides of the deal agree to exchange cash flows, which are derived from the price of an underlying commodity.	OTC	Cash
Options[12]	An option provides the buyer with the right but NOT the obligation to buy (call) or sell (put) an asset at an agreed upon price (strike price) during a certain period of time or on a particular date (exercise date).	Traded on an exchange with standard settlement dates.	Cash
			Physical optionality possible
Structured Products	Unique products designed to meet a particular hedging requirement. Typically higher cost/lower liquidity than standard products.	Typical counterparty is an investment bank.	Specific to product

In some instances, NSPI may use alternative, highly correlated financial products to hedge a specific risk because either an effective hedging instrument does not exist or existing products are not sufficiently liquid.[13] The correlated product may be a contract on the same underlying commodity but differ in terms of delivery date, product quality, or delivery point; it may be a contract on a different commodity that has highly correlated price movements with the product to be hedged. The effectiveness of these types of hedges is measured through analysis of the relationship between the price movements in the underlying exposure and those of the hedging product.

10 Fuel Hedging Plan, pages 5–7.

11 One side of the commodity swap, the floating leg, is tied to the price of a commodity or a commodity index, while the payments on the other side, the fixed leg, are stipulated in the contract. It is common for a commodity swap to be settled in cash, although physical delivery is possible. The floating leg is typically held by a commodity consumer that is willing to pay a fixed rate for a commodity to guarantee its price. The fixed leg is typically held by a commodity producer that agrees to pay a floating rate, which is set by the market price of the underlying commodity, thereby hedging against falls in the price of the commodity. In most cases, swap rates are fixed either by commodity futures or by estimating the commodity forward price.

12 Permissible contract types include swing options. A swing options contract states the least and most energy an option holder can buy (or "take") per day and per month, how much that energy will cost (its strike price) and how many times during the month the option holder can change (or "swing") the daily quantity of energy purchased.

13 Fuel Hedging Plan, page 10.

Appendix C of the Fuel Hedging Plan lists the hedging products NSPI anticipated using during the RSP for each fuel. These are shown in Figure XII-3 below. The use of any other products requires pre-approval from the Fuel Strategy Table.[14]

Figure XII-3. Approved Hedging Products per the Fuel Hedging Plan[15]

Fuel	Primary Financial Hedging Index	Secondary Financial Hedging Index(ices)	Physical Hedging Opportunities
Coal	[redacted]		
HFO			
Natural Gas			
Electricity Imports			

XII.A.1.b.ii. Counterparties

NSPI is permitted to use both bilateral, over-the-counter (OTC) transactions and exchange-cleared transactions (e.g., NYMEX) in hedging.[16] One main difference between OTC and exchange trades is counterparty risk; OTC transactions are riskier because NSPI is exposed to the credit risk of the counterparty, whereas exchanges require transacting parties to post credit security in order to transact. On the flip side, exchange transactions have higher up-front cash flow requirements than bilateral trades due to margin requirements at the exchanges. Bilateral counterparties may be entered into with either financial or non-financial parties.[17] For OTC trades, which again are riskier than exchange trades, the Fuel Hedging Plan recommends that master trading agreements be used whenever possible—this helps mitigate risk and impose standardized terms and conditions on NSPI's OTC hedging transactions.[18]

14 Fuel Hedging Plan, page 5.

15 Fuel Hedging Plan, Appendix C.

16 Fuel Hedging Plan, page 12.

17 Fuel Hedging Plan, page 12.

18 NSPI procures its financial hedging products through a number of OTC and exchange traded (centrally cleared) contracts. The OTC contracts were executed pursuant to ISDA master trading agreements. The cleared contracts are primarily executed through the Intercontinental Exchange's WebICE trading platform. Brokers are occasionally used for trading in illiquid markets.

XII.A.1.b.iii. Strategy and Rebalancing

Prior to the RSP, NSPI aimed to optimize its fuel and purchased power portfolio through fuel switching.[19] As the relative prices of fuels changed, NSPI would procure more of the cheaper fuel. For example, in the winter of 2015–2016, natural gas prices were generally higher than HFO prices, resulting in a low forecast of natural gas consumption. When the spot price of natural gas fell below the forecast price, NSPI procured incremental gas at a lower price.[20]

The ability to fuel switch is a real option by which NSPI can use the flexibility in its generation fleet to optimize its fuel and purchased power portfolio during the RSP. However, the majority ([redacted]) of forecast consumption during this period is to be hedged in advance. Hedged volumes will incur a loss (gain) as prices fall (rise). Unhedged volumes can take advantage of the lower market prices but are exposed to increases in prices. As part of the Fuel Hedging Plan, NSPI stated that, subject to available liquidity in suitable hedging products, it would reach its targeted position of [redacted] hedged by the end of 2016 and would rebalance on a quarterly basis throughout the RSP.

Rebalancing the hedging portfolio, unwinding existing hedges, or executing new hedges is based on the results of the quarterly updates to the fuel consumption forecasts, available liquidity in the relevant hedging products, and recognition of any resulting gains or losses.[21] Volumetric requirements for each fuel are derived from the PLEXOS model, which is to be updated no less than quarterly during each year of the RSP.[22] For example, at the beginning of a quarter, NSPI may show that it is 80% hedged for its expected petcoke needs for the following year; however, if during the quarter the price of petcoke falls substantially relative to other fuels, it may be that the next quarterly PLEXOS forecast shows a significant increase in expected petcoke consumption over the next year. Thus, NSPI would no longer be 80% hedged, and it would seek to procure additional hedges as part of the rebalancing process, subject to the available liquidity in a relevant petcoke hedging product.

XII.A.1.b.iv. Unhedgeable Risks

NSPI notes in its Fuel Hedging Plan that "there will always be residual, un-hedgeable risk in the portfolio that means actual fuel costs will differ from forecasts."[23] NSPI identifies five specific risks for which a direct economic hedge either is not available or would be of prohibitive cost:[24]

[redacted]

[redacted]

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[19] Fuel Hedging Plan, page 9.

[20] Fuel Hedging Plan, page 10.

[21] Fuel Hedging Plan, page 9.

[22] Fuel Hedging Plan, page 19.

[23] Fuel Hedging Plan, page 4.

[24] Fuel Hedging Plan, pages 15–16.

[redacted]

XII.A.1.b.v. Procedure and Oversight

As noted in the Fuel Hedging Plan, planning, executing, monitoring, and reporting of hedges requires coordination across NSPI. The FST governs fuel procurement and hedging subject to both the Risk Management Policy and the Credit Policy. The Portfolio Optimization Group is responsible for running the PLEXOS models to produce the fuel forecasts. The Fuel Finance team translates the PLEXOS model output into a forecast of expected cost for the fuel and purchased power. The FERM team is responsible for executing fuel procurement transactions, including hedging. Once the FST has approved a particular strategy and/or trade, the primary responsibility for the hedge execution belongs to the Financial Trader and Physical Optimization Specialist.[25]

NSPI's Fuel Procurement Risk Management Policy and Procedures manuals state that effectiveness testing reports are to be produced on a quarterly basis and monthly during the December–February period.[26] These reports are distributed to the CROC. Hedging reports are to be produced on a monthly basis and are distributed to the Fuel Strategy Table.[27]

Exposure to the credit risk of the counterparty in bilateral transactions is monitored by the ERM and reported to FERM and management. The FST, ERM, or CROC is responsible for actions in response to these reports when called for by NSPI's credit policies.[28]

XII.B. Findings

XII.B.1. Assessment of NSPI's Hedging Program

We assessed the effectiveness of NSPI's hedging activities during the Audit Period by first considering whether NSPI's hedging is meeting the provincial goal of greater stability in electricity rates, a target that is laid out in the first paragraph of NSPI's Fuel Hedging Plan.[29] Our assessment looks at the impact of NSPI's hedging on the stability of rates. We examine the consistency of NSPI's hedging activities with the objectives and requirements as set forth in NSPI's governing documents. Next, we provide an assessment of the effectiveness of NSPI's hedging activities at the portfolio level. We do this

25 Fuel Hedging Plan, pages 19–20 and Appendices E, F, and G.

26 As discussed in the Findings section, as part of an external compliance audit undertaken by Deloitte LLP, the requirement of monthly reports is no longer necessary.

27 NSPI, Fuel Procurement Risk Management Policy & Procedures, January 13, 2014, and May 30, 2016, page 16.

28 Fuel Hedging Plan, page 12.

29 Fuel Hedging Plan, page 3.

by considering portfolio-level regression analysis, estimates of portfolio VaR, a review of hedging program costs (e.g., transaction fees), and associated gains and losses on the hedging positions themselves. We then look at NSPI's hedging activities for success at the individual fuel level by considering estimates of hedging transactions' impact on VaR by fuel; we also review NSPI's procurement processes for acquiring hedges. In addition, we assess the relationship between the hedged product and the fuel being hedged through the application of regression analysis to individual trades. Finally, we assess the operation of the hedging plan during a period of extreme volatility in natural gas prices.

XII.B.1.a. Consistency with EPIA Objectives

The primary objective of the RSP is to produce stable rates for FAM customers over the three-year term. To do this, the EPIA required NSPI to establish a single FAM rate applicable to each year in the RSP. Further, because setting a single rate for a three-year period to recover fuel and purchased power costs—which can be volatile—will necessarily result in under- or over-recovery of actual costs, the EPIA required NSPI to include in its Fuel Stability Plan "a description of any hedging strategies or mechanisms proposed to be used by Nova Scotia Power [will] manage fuel costs during the Rate Stability Period."[30] Ideally, NSPI's hedging activities would minimize over- and/or under-recovery of actual fuel and purchased power costs over the RSP. This is a particularly important objective in avoiding large rate impacts in 2020, the year after the RSP ends. (We note that the EPIA requires that NSPI include a forecast of fuel costs for 2020 in its Fuel Stability Plan;[31] moreover, in approving the Company's Fuel Stability Plan, the Board noted NSPI's concerns about possible 2020 rate impacts.[32])

A reasonable metric for judging the success of the hedging program is to measure the dollars-per-MWh difference between (1) the costs recovered by NSPI under the existing fixed rate[33] and (2) actual fuel costs incurred by NSPI. The closer these two numbers are the better, as that implies less over- or under-recovery that must be addressed at the end of the RSP. Figure XII-4 below shows results so far, as of the end of the Audit Period. Specifically, Figure XII-4 compares the "RSP Compliance Filing" rate—which is the fixed, three-year rate to be charged to NSPI's FAM customers through the end of 2019—to NSPI's actual fuel costs. NSPI's actual fuel costs are shown through the end of 2017; NSPI's forecasted fuel costs are shown for 2018–2019, as updated by NSPI in the rebalancing process.

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30 EPIA, paragraph 4(1)(d).

31 EPIA, paragraph 4(1)(a).

32 2016 NSUARB 129 (M07348), paragraph 7. "Consistent with the normal practice in prior BCF proceedings, NSPI updated the BCF forecast contained in its original Application with pricing information as of March 31, 2016. It filed its 2017–2019 BCF Refresh on May 27, 2016. This 2017–2019 BCF Refresh reduced the overall annual average increase in FAM customer rates over the Rate Stability Period from 1.3% (as originally set out in the Application) to 1.0%. However, recognizing the concerns expressed by some about the possible 2020 rate impacts, NSPI indicated in its filing that it was:

> …open to recovery of average annual rate increases in the range of 1.0 to 1.3 percent if such recovery is deemed to be in the best interest of customers and supports stable predictable and affordable rates through the Rate Stability Period."

33 As set out in the FAM Plan of Administration, the Base Cost of Fuel can be reset in a General Rate Application every second year as part of the FAM adjustment process. In 2016, the BCF was set for the entire three-year RSP.

Figure XII-4. Comparison of Fixed RSP FAM Rate to NSPI's Actual Fuel Costs

[redacted]

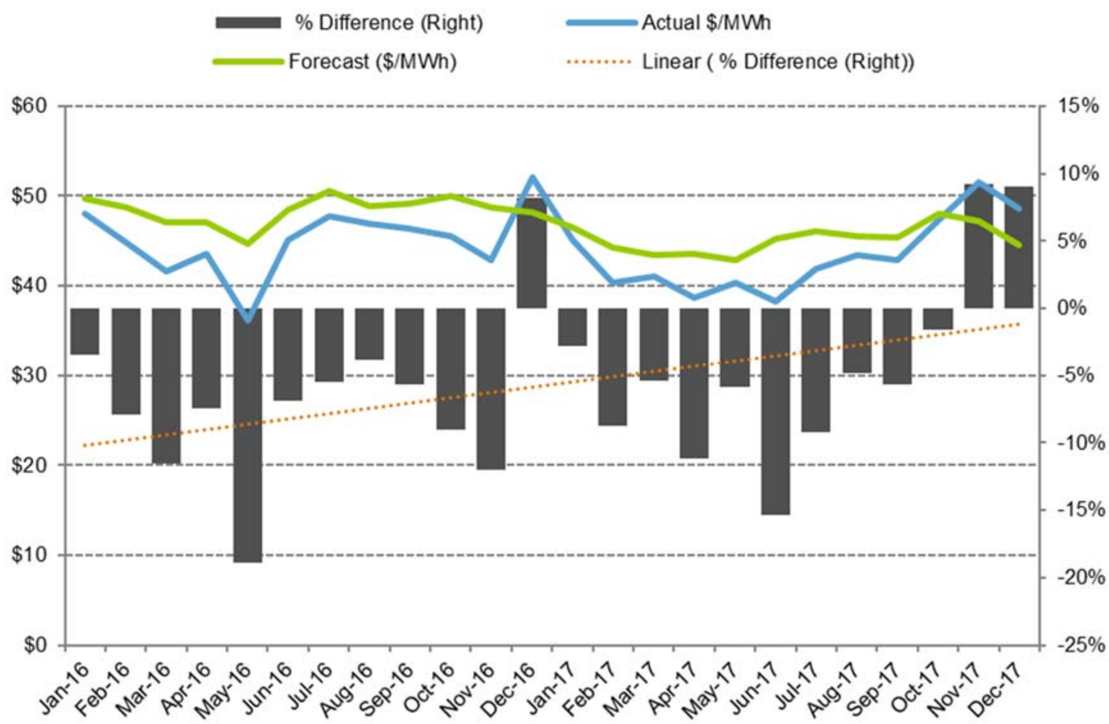
Figure XII-4 demonstrates two points. First, NSPI's actual costs have tracked reasonably closely to its fixed FAM rate. This will help minimize any true-ups that need to be made at the end of the RSP. Second, NSPI has over-recovered FAM costs so far and is forecasted to over-recover for the full period. This means that at the end of the RSP, NSPI will owe a refund to FAM customers. Figure XII-5 provides additional specificity regarding the forecasted over-recovery, as projected by NSPI the end of the Audit Period—note that NSPI projects a [redacted] over-recovery by the end of the RSP.

Figure XII-5. Projected Recovery Ending Balance, as of Q4 2017

[redacted]

It is difficult to derive the precise impact of NSPI's hedging activities on these results. Many factors can drive differences between the fixed FAM rate and the actual FAM costs; for example, as shown in Figure XII-6 below, NSPI's forecasts of $/MWh fuel costs were higher than what was observed during the Audit Period, which can drive over-recoveries of fuel costs. Moreover, as noted above and in the Fuel Hedging Plan, NSPI faces numerous un-hedgeable risks, such as [redacted]. Nevertheless, the data shown in Figure XII-4 and Figure XII-5 are not concerning and are evidence that NSPI is managing the RSP's mandates well so far. To further assess the effectiveness of NSPI's hedging activities, we must consider a number of other metrics.

Figure XII-6. Monthly Fuel Costs, $/MWh, Total Generation



XII.B.1.b. Consistency with Hedging Plan Requirements

The next way we assessed NSPI's hedging activities during the Audit Period was to review NSPI's compliance with the plain language of the Fuel Hedging Plan regarding hedging targets. As noted above, under the Fuel Hedging Plan, NSPI sought to hedge [redacted] of its forecasted fuel consumption during the RSP, "subject to available liquidity in suitable hedging products."[34]

Our review of NSPI's data suggests that NSPI met the targets of its Fuel Hedging Plan for most fuels; for those fuels (and purchased power) for which it did not hedge at least [redacted] of its forecasted consumption, NSPI's decision to do so was due to a lack of availability of suitable hedging products. For example, there are no available, suitable products to hedge NSPI's power purchases under the Joint Dispatch Agreement with New Brunswick; as a result, NSPI hedged less than [redacted] of its forecasted purchased power consumption. Heavy fuel oil, meanwhile, also creates a challenge for NSPI due to the small quantities NSPI purchases and the difficulty in pairing lumpy physical deliveries to NSPI's modest oil needs.

Our review also shows that NSPI met these hedge targets by the beginning of the RSP (i.e., January 1, 2017), having built its hedge positions beginning shortly after the passage of the EPIA and throughout 2016—even before the Board approved the Fuel Hedging Plan in November 2016. NSPI's decision to do this was prudent. Building hedge positions of the size and scope required by NSPI's Fuel Hedging Plan is

[34] Fuel Hedging Plan, page 8.

best done over a longer period of time to minimize market impact and reduce the likelihood of paying premiums to achieve large hedge positions on short notice.

Figure XII-7 shows NSPI's hedge positions in three different time periods: end of first quarter, 2016; end of fourth quarter, 2016, and end of fourth quarter, 2017. Note, again, that by the end of the fourth quarter of 2016, NSPI had reached its targets for solid fuel and for its exposure to the Henry Hub price for natural gas. Note, too, that the fourth quarter 2017 data are the product of and subject to the "rebalancing" process, which we discuss in the next subsection.

Figure XII-7. Compliance with Hedging Targets in the Fuel Hedging Plan[35]

Solid Fuel	Solid Fuel Transport	Natural Gas	Power	Fuel Oil
[redacted]				

XII.B.1.c. Compliance with Quarterly Rebalancing Provisions of Fuel Hedging Plan

The Fuel Hedging Plan calls on NSPI to actively update and manage its hedge portfolio throughout the hedging plan. Specifically, the Fuel Hedging Plan states:

> As assumptions (especially fuel pricing) change, the PLEXOS model will be updated periodically, and no less than quarterly during each year of the RSP. Each forecast will provide a new volumetric requirement for each fuel; to the extent that changes are

[35] NSPI FAM Quarterly Reports, 2016 Q1, 2016 Q4 and 2017 Q4, Sheet Q1.

> material, the hedge portfolio will be rebalanced to reflect the current forecast. [NSPI] defines a change as material if the new volumetric forecast results in the percent hedged for any underlying fuel falling outside of the [redacted] target range. This could necessitate the addition of new hedges and/or the unwinding of existing hedges.[36]

We reviewed NSPI's rebalancing activities during 2017 to determine if (1) NSPI was conducting quarterly rebalancing and (2) how NSPI's quarterly rebalancing activities translated into additional hedging activity. Our review showed that NSPI did conduct quarterly rebalancing, using updated fuel consumption forecasts from PLEXOS to determine whether NSPI would need to enter into additional hedges or unwind existing hedges to remain in compliance with Rate Stability Period targets. We also noted NSPI's practices in rebalancing: following the update to the fuel consumption forecasts, the Director of Portfolio Optimization presented recommendations to the FST seeking approval to execute certain trades/purchases to rebalance the portfolio.

The quarterly rebalancing memorandum also provided explanations for exceptions to the Fuel Hedging Plan. For example, the December 2017 memo noted that the percentages hedged of 2018 and 2019 natural gas would be above [redacted] to mitigate "the risk of longer than expected Wreck Cove outages, uncertainty in Nova volumes, and the risk of not achieving forecast higher import volumes." While the [redacted] hedged position for HFO was outside the RSP target, this is explained by the mismatch between consumption and the "lumpy delivery schedule." Subject to approval and liquidity, the execution trader executes and tracks the required trades.

To provide an example of NSPI's rebalancing efforts, Figure XII-8 shows the rebalancing trades that were recommended and approved by the FST as of the end of the final quarter of the Audit Period. The table shows that NSPI sought to unwind hedges on [redacted]—which hedge its low-sulphur coal positions—and [redacted] due to updated quarterly PLEXOS forecasts, which showed NSPI being overly long in both products. Meanwhile, Figure XII-8 also shows that NSPI will seek to hedge [redacted] of its exposure to the price difference between the Henry Hub and AGT-CG.

[36] Fuel Hedging Plan, page 9.

Figure XII-8. Recommended Rebalancing, 2017 Q4

Commodity	Product	Units	Volume 2018	Volume 2019	Notional Values[37] (US$M)
[redacted]					

* [redacted]

XII.B.1.d. Portfolio-Level Assessment

We next reviewed NSPI's hedging activities' effectiveness on a portfolio level. We sought to review, using statistical metrics, the effectiveness of NSPI's entire hedging portfolio on its entire actual and forecasted fuel consumption costs and exposure. To do so, we looked at two metrics: (1) portfolio level regressions and (2) portfolio VaR. We address these items below. We conclude this section with (3) a look at the total transaction costs and fees associated with NSPI's hedging transactions and (4) NSPI's hedging procurement process.

XII.B.1.d.i. Portfolio-Level Regression Analysis

Our first portfolio-level look at the effectiveness of NSPI's hedging activities was to consider how closely changes in the value of NSPI's hedge portfolio—comprised of both physical and financial positions—offset, or hedge, the value of NSPI's forecasted fuel consumption for the remainder of the RSP, where these values are viewed as short positions. A short position in a product is defined as a position for which NSPI does not yet hold the product that it requires, that is, is not "long" the product. Therefore, if NSPI is short and prices rise, it will be spending more to cover, or fill, its need.[38] An effective hedge portfolio will rise in value if fuel prices rise, offsetting (moving opposite to) the increasingly larger cost required to meet need. As a result, NSPI and its customers are insulated from rising fuel prices. To demonstrate whether this is true, linear regression analysis is appropriately used by NSPI. We reviewed their portfolio-level regression results and found that NSPI's overall hedge portfolio has been effective during the Audit Period.

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37 Notional values are the total value of a leveraged position's assets. This term is commonly used in the options, futures, and current markets because of leverage, wherein a small amount of invested money can control a large position in the markets. For example, one S&P 500 index futures contract obligates the buyer to 250 units of the S&P 500 index. If the index is trading at $1,000, then the single futures contract is similar to investing $250,000 (250 * $1,000). Therefore, $250,000 is the notional value underlying the futures contract. http://www.investopedia.com/terms/n/notionalvalue.as#ixzz4jfCoJyOt

38 Being long a product during a rise in price increases the value of your holdings. As a result, these portfolios move in opposite directions.

The regression analysis measures how closely the day-to-day change in the market value of the hedge portfolio tracks the day-to-day change in the market value of NSPI's fuel consumption forecast costs (entered as short positions). Two regression statistics matter most: the slope of the regression line and the "R-squared" of the regression, which is a measure of how closely the regression line fits the data. The Fuel Hedging Plan defines an acceptable range for the former to be between –0.8 and –1.25, and an acceptable range for the latter to be between 0.8 and 1.0.[39] As is shown in Figure XII-9, NSPI's portfolio of hedges was effective in all four quarters of 2017 as measured by both the slope and R-squared metrics. For example, in the fourth quarter of 2017, NSPI's hedge portfolio had a slope of –0.91, which means that for every dollar NSPI's expected fuel consumption costs increased for the remainder of the Audit Period, NSPI's hedge portfolio increased in value by 91 cents, while also having a sufficient R-squared value of 0.84 (implying an acceptable fit of the regression line to the data).

Figure XII-9. Portfolio-Level Regression Analysis Output

Quarter	Slope Coefficient	R-Square
2017 Q1	-0.8	0.84
2017 Q2	-0.82	0.86
2017 Q3	-0.92	0.84
2017 Q4	-0.91	0.84

XII.B.1.d.ii. Portfolio VaR

The second portfolio-level assessment we did of NSPI's hedging activities during the Audit Period was to consider NSPI's entire hedge portfolio's impact on NSPI's VaR. Recall that VaR is an industry standard risk measurement metric that calculates the dollars—or value—at risk given a particular holding period at a particular probability of loss. NSPI uses reasonable parameters in defining VaR, specifying a one-day holding period and a 95 percent confidence interval, while using the historical volatilities and correlations of the individual fuels over the previous 90 days.[40] A VaR of $5 million would imply that, assuming the volatilities in the prices of each fuel over the past 90 days, and the correlation between the prices of fuel over the past 90 days, NSPI has a risk of losing a maximum of $5 million in the next day—subject to a 95% confidence interval. The higher the VaR relative to the value of the unhedged portfolio, the riskier the portfolio.

If effective, NSPI's hedge portfolio will reduce NSPI's VaR. We found that NSPI's hedge portfolio was effective in significantly lowering NSPI's VaR. For example, data for 2017 Q1 indicated that in the absence of hedging, the portfolio exposed customers to approximately [redacted] of risk; the hedged portfolio reduced this amount to approximately [redacted], a reduction in risk of 72%. Results for each quarter of 2017 are presented in Figure XII-10 below.

39 Fuel Hedging Plan, page 10.

40 Fuel Hedging Plan, page 16.

Figure XII-10. Portfolio VaR Impact of NSPI's Hedging

Portfolio Effectiveness VaR	
2017 Q1	-72%
2017 Q2	-76%
2017 Q3	-70%
2017 Q4	-66%

XII.B.1.d.iii. Portfolio Hedging Costs

Though effective by the measures noted above, NSPI's hedging activities have costs, and it is important to assess those costs and ensure they are not excessive relative to their risk-reducing benefits for NSPI's FAM customers. The Fuel Hedging Plan specifies that NSPI's hedge acquisitions will have costs that are neither "out of proportion to what the same product is selling at similar markets" or "more than the measured consequence of the risk as per the aforementioned best practice calculation of value at risk."[41]

NSPI tracks hedging execution costs (fees and commissions) at a portfolio level. These costs are presented in Figure XII-11 below. For the entire Audit Period, hedging costs totaled about [redacted], a reasonable amount, given the volume of hedge transactions NSPI entered and given the size of the reductions in portfolio VaR (e.g., approximately [redacted] in first quarter 2017).

Figure XII-11. Portfolio Hedging Costs (by Quarter)

Quarter	Hedging Costs (USD)
2016 Q1	[redacted]
2016 Q2	
2016 Q3	
2016 Q4	
2017 Q1	
2017 Q2	
2017 Q3	
2017 Q4	
Total	

We also note here that even though it is not a measure of hedge effectiveness, when a hedge settles, the realized gain or loss is reflected as an adjustment to the cost of inventory for storable fuels, such as solid fuel and oil, or as an adjustment to the cost of consumption for non-storable commodities such as natural gas and power.[42] Where a recommended rebalancing will result in locking in a gain (or loss), this is noted in the quarterly portfolio re-balancing reports. For example, reports for the second and third

41 Fuel Hedging Plan, page 15.

42 Unrealized gains and losses are recorded on a quarterly basis as "Held for Trading Assets and Liabilities, with an offsetting amount recorded as a Regulatory Asset or Liability."

quarter included statements that the recommended trades would capture approximately [redacted] and [redacted] of mark-to-market gains.

XII.B.1.d.iv. NSPI's Hedge Procurement Process

NSPI's process for procuring hedges is reasonable. NSPI transacted for hedges through RFPs, direct negotiation with OTC counterparties, OTC contracts facilitated by brokers, and on the Intercontinental Exchange. These transactions are based on transparent market offers from counterparties and provide comfort that the transaction was made at a reasonable market-based cost. OTC transactions are less transparent, but we observed evidence that NSPI acquired hedges at a reasonable cost. First, we observed that NSPI maintains master agreements[43] with [redacted] counterparties that effectuate trading at standardized terms and conditions, limiting counterparty risk and lowering transaction costs. Second, NSPI transacted with several counterparties during the Audit Period across a variety of products—see Figure XII-12 below for details, which shows all [redacted] ISDA counterparties and the actual products transacted during the Audit Period, if any.

Figure XII-12. Hedge Transaction Counterparties

Counterparty	Product - 2016	Product - 2017
[redacted]		

XII.B.1.e. Fuel-Level Hedge Assessment

Our next assessment was to consider NSPI's hedge effectiveness on a fuels basis—that is, how effective was NSPI's hedging for, say, coal? This would demonstrate if NSPI's overall hedge portfolio results were masking any concerns regarding a particular fuel. To do this, we considered impact on VaR on a fuel-specific basis. The calculation of VaR is also addressed in Section 3 (Operation of the Fuel Hedging Plan in a Period of Price Volatility).

We found that NSPI's hedge portfolio was effective in significantly lowering NSPI's VaR across all fuels in all quarters, except, in some cases, heavy fuel oil, which we explain below. The 2017 fuel-specific percentage changes in VaR due to NSPI's hedging activities are shown in Figure XII-13 below.

43 Such agreements are International Swaps and Derivatives Association (ISDA) agreements.

Heavy fuel oil is characterized by "lumpy" delivery volumes from individual cargoes which result in a mismatch on the annual forecast consumption of HFO due to limitations on storage.[44]

Figure XII-13. Reduction in Value at Risk, by Fuel

	Coal	Natural Gas	Power	Fuel Oil
2017 Q1	[redacted]			
2017 Q2				
2017 Q3				
2017 Q4				

XII.B.1.f. Assessment of Individual Hedges

We then looked at NSPI's hedge effectiveness on an individual transaction-level basis. Here, we considered each hedge transaction to assess whether it was effective, and then aggregated those data to determine the percentage of NSPI's individual transactions that were effective. Like the portfolio-level analysis, effectiveness of an individual transaction is measured through regression analysis. The regression considers the relationship between changes in the price of a hedge instrument and the price of the underlying product it is intended to hedge. A hedge will gain in value when the cost of the underlying product gains in value, and vice-versa.

NSPI defines an individual hedge to be effective if the regression result for a specific trade has an R-squared of at least 0.8 and a slope in the range of 0.8–1.25. The effectiveness of the hedge transactions undertaken during 2016 are presented in Figure XII-14 below, which shows a high percentage of NSPI's hedges being effective.

Figure XII-14. Trade Regression Analysis, 2016

Percentage of Trades Effective based on Regression Analysis	
2016 Q1	100% (54 of 54)
2016 Q2	91% (126 of 139)
2016 Q3	93% (182 of 195)
2016 Q4	99% (243 of 245)

A closer review of the 2016 results indicated that in all periods, all "ineffective" trades involved the Platts Dated Brent price index[45] as a hedge on the assessed price of Platts No. 6, 1.0% NY Spot Cargo. These trades represented approximately [redacted] of all trades involving [redacted]. When there is not enough liquidity in the [redacted] market to hedge directly,

[44] There are limitations on the storage of HFO at NSPI's facilities and the actual amount required can vary from the forecast volume due to the price relationship between natural gas and HFO. An RFP for a cargo of HFO is issued when the forecast inventory level is low enough to accept a cargo.

[45] Intercontinental Exchange, "Dated Brent Future," ***available at*** https://www.theice.com/products/6753541/Dated-Brent-Future.

NSPI utilizes [redacted] as a proxy due to the high correlation between the [redacted] and the [redacted]. [redacted]. This index is representative of market value, but is a derived index drawn from a review of bids, offers, and transactions. The ineffective trades varied in size and were undertaken with various counterparties. In addition, not all [redacted] trades were ineffective. This suggests that the issue was the result of these trades being cross-product hedges.[46]

Turning to 2017 data, we see that NSPI's hedging on an individual transaction basis remained strong. Results for 2017 are presented in Figure XII-15 below. As with the results in 2016, the ineffective trades primarily involved [redacted].[47]

Figure XII-15. Trade Regression Analysis (2017)

Percentage of Trades Effective based on Regression Analysis	
2017 Q1	98.8% (254 of 257)
2017 Q2	96.6% (280 of 290)
2017 Q3	96% (310 of 324)
2017 Q4	96% (370 of 386)

XII.B.2. Fuel Hedging Plan's Consistency with Other Guidelines

NSPI's Fuel Manual contains guidelines for solid fuel portfolio processes. The Solid Fuel Portfolio Process, contained within the Fuel Manual, details the position requirements of NSPI's solid fuels physical (inventory and fixed price contract volumes) and financial hedges.[48] A primary component of these requirements is found in Table 1 of the Solid Fuel Portfolio Process, which is reproduced in its entirety here as Figure XII-16.

46 As noted in the Fuel Hedging Plan, page 10, for some fuels the available financial products are not sufficiently liquid to permit NSPI to hedge the specific risks. Therefore, NSPI may use alternative highly correlated financial products to hedge these fuels.

47 NSPI undertook one ineffective trade to [redacted]. These types of trades are executed using the closing price from the previous day to close (sell) the position from one book and open (buy) the position into another book permitting allocation of mark to market increases or decreases to the appropriate term.

48 Fuel Manual Revision 10, Link 6, "Solid Fuel Portfolio Process, Fuels, Energy & Risk Management," Version 2017.

Figure XII-16. Solid Fuel Portfolio, Physical and Financial Hedges, Required Position, Percentages[49]

As of End of Current Year	Current +1 Year	Current +2 Year	Current +3 Year	Current + 4 Year
% Positions Required Hedged - Min	60*	35	20	0
% Positions Required Hedged - Max	85	75	65	50

*For Current +1 year, minimum volume must be contracted for physical volumes.
Financial hedges include hedges where no physical volumes have yet been purchased.

The guidelines found in Figure XII-16 appear to conflict with the [redacted] guideline for each fuel contained in the Fuel Hedging Plan. The discrepancies between position guidelines as contained in the Fuel Manual and as required by the Board-approved Fuel Hedging Plan should be eliminated or clarified. We provide a conclusion and recommendation addressing this issue below.

XII.B.3. Operation of the Fuel Hedging Plan in a Period of Price Volatility

Finally, we assessed the operation of the hedging plan in a period of price volatility. That is, we selected a month in which a fuel price had high volatility and analyzed NSPI's performance under the Fuel Hedging Plan during that time. To do this analysis, we looked at NSPI's natural gas trading, hedging, and operational activities in December 2017. While prices at Henry Hub were relatively stable throughout the Audit Period, that month saw a spike in the price of gas at AGT-CG, resulting in a spike in the AGT-CG basis (spread) over Henry Hub for delivery to AGT-CG. Figure XII-17 shows AGT-CG prices for the Audit Period—the December 2017 price spike is evident at the far right side of the figure.

49 Fuel Manual Revision 10, Link 6, "Solid Fuel Portfolio Process, Fuels, Energy & Risk Management," Version 2017, Table 1, page 5.

Figure XII-17. Natural Gas Prices, Algonquin City Gate and Dawn, Ontario, Audit Period, $/MMBtu

[redacted]

To hedge its exposure to December 2017 natural gas prices, NSPI used three strategic hedge mechanisms, each of which is contemplated in the Fuel Hedging Plan. First, NSPI used "operational changes" to hedge its exposure to natural gas; that is, NSPI's dual-fuel units at Tufts Cove can burn heavy fuel oil instead of natural gas, if natural gas becomes more expensive than oil.[50] We observed that NSPI avoids contracting for firm, fixed-price, monthly physical natural gas in the winter to maximize the value of its fuel switching flexibility. This hedge dictates that when natural gas prices rise and become expensive relative to HFO, NSPI would switch to HFO for burn at Tufts Cove.

Second, NSPI entered into two physical contracts for a total of [redacted] per day of must-take natural gas priced at the [redacted] daily index prices and [redacted] index prices, plus the respective fixed adders. This is shown in Figure XII-18 below. Both contracts allowed NSPI to resell the physical gas, which served as a partial hedge against volatile natural gas prices. (We provide the details of NSPI's sales of natural gas under these contracts during December 2017 in the Natural Gas Procurement chapter.)

Figure XII-18. Contracts for Physical Delivery of Natural Gas in December 2017

	Contract Date	Volume (MMBtu/Day)	Price Index	Adder
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

50 See, for example, Fuel Hedging Plan, page 12.

Third, NSPI hedged its exposure to December 2017 natural gas price using monthly financial contracts. Beginning in mid-2016, NSPI purchased NYMEX December 2017 futures equivalent to [redacted] per day at Henry Hub and [redacted] per day for the AGT-CG basis differential to Henry Hub.[51] Recall from the Natural Gas Procurement chapter that the price NSPI pays for gas is often reasonably estimated by taking the Henry Hub price and adding a "basis," or differential, to account for the price index location. That basis is best addressed by looking at the prices for gas at the AGT-CG, which are for gas delivered to gas utilities and end users in Connecticut, Rhode Island, and Massachusetts.[52] Henry Hub prices, in general, tend to be considerably lower than the price at the Algonquin City-Gates during the winter months. Thus, a reasonable hedge for NSPI's exposure to gas prices would include both a Henry Hub contract and an Algonquin basis contract. Figure XII-19 below shows all NSPI's financial contract hedges for December 2017 natural gas prices. An additional fixed "adder" reflects the locational difference between the price index location and NSPI's physical location.

Figure XII-19. Financial Hedge Contracts (Natural Gas) in place for December 2017

Henry Hub			
Trade Date	Trade Number	Volume	Open Price
1-Jun-16	[redacted]	[redacted]	[redacted]
10-Jun-16	[redacted]	[redacted]	[redacted]
14-Nov-16	[redacted]	[redacted]	[redacted]
14-Nov-16	[redacted]	[redacted]	[redacted]
16-Mar-17	[redacted]	[redacted]	[redacted]
21-Jun-17	[redacted]	[redacted]	[redacted]
8-Sep-17	[redacted]	[redacted]	[redacted]
11-Sep-17	[redacted]	[redacted]	[redacted]
Total		[redacted]	[redacted]

AGT Basis			
Trade Date	Trade Number	Volume	Open Price
25-May-16	[redacted]	[redacted]	[redacted]
27-May-16	[redacted]	[redacted]	[redacted]
15-Nov-16	[redacted]	[redacted]	[redacted]
23-Mar-17	[redacted]	[redacted]	[redacted]
20-Jun-17	[redacted]	[redacted]	[redacted]
Total		[redacted]	[redacted]

Entering December 2017, NSPI expected to burn [redacted] per day for the month, with a minimum burn of [redacted]. These are important numbers to know when assessing NSPI's hedging approach. With this as background, we note the following key findings:

- First, NSPI's total physical, contracted volume for the month equaled its minimum expected gas consumption for the month—[redacted]. We found this to be a reasonable approach. The must-take physical contracts provided a quantity hedge for NSPI, and while the contracts did not provide a price hedge (since these physical contracts were priced at their respective daily index), they did provide some price protection due to NSPI's right to re-sell the physical gas. NSPI could exercise this option for economic reasons and/or because they did not need to burn all [redacted] of the gas on a given day, thereby mitigating a portion of the price risk. This feature served as

[51] Trade dates ranged from June 1, 2016 to September 11, 2017 for Henry Hub and May 25, 2016 to June 20, 2017 for AGT-CG Basis.

[52] S&P, "Methodology and specifications guide North American natural gas," June 2018, page 8, ***available at*** https://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_gas_methodology.pdf

an imperfect (partial) hedge on NSPI's price exposure on these [redacted] of gas.[53]

- Second, we saw evidence that NSPI considered the value of its fuel-switching capabilities at Tufts Cove in making decisions about buying physical gas. We also observed NSPI reducing its gas consumption and increasing its oil consumption on days of very high gas prices in December. This is shown in Figure XII-20 below. However, we also noted that for this operational hedge of its fuel-switching capabilities to be effective, NSPI had to be able to fairly quickly switch to burning HFO to avoid burning more expensive gas. A review of the gas traders' operational notes for December 2017 indicates that other operational problems (generator availability, transmission testing, etc.) sometimes affected NSPI's ability to switch to HFO.

Figure XII-20. Natural Gas MMBtu Burn vs. Natural Gas Price at Algonquin City Gate, Daily (December 2017)

[redacted]

- Third, regarding NSPI's financial hedge contracts, as shown in Figure XII-19 above, we observed that NSPI appropriately built its positions over time, procuring hedge contracts for both the Henry Hub and AGT-CG basis throughout 2016 and 2017. However, we also noted that NSPI's financial hedge contracts did not fully hedge NSPI's exposure to natural gas price volatility. This is because NSPI's financial hedges for both Henry Hub

[53] We note, however, that this de facto hedge carries risk: NSPI must find a willing counterparty to buy the gas, and the price at which NSPI sells the gas may be below the index price. Notably, as we explain in the Natural Gas Procurement chapter, when NSPI sought to sell natural gas during December 2017, it did so at a loss.

and the AGT-CG basis settled on the "first-of-the-month" prices—while NSPI's physical gas was purchased at daily prices throughout December 2017. So while the monthly financial gas hedge provided some protection to price exposure, NSPI remained exposed to daily gas prices. We prove this below.

- Fourth, NSPI considers its monthly gas price financial hedges as sufficient to hedge its exposure to natural gas prices. We observed this directly in NSPI's Record of Approvals for natural gas procurement and hedging decisions.
- Fifth, NSPI's decision to hedge just [redacted] of the AGT-CG basis while hedging a full [redacted] of Henry Hub prices for December 2017 appears reasonable. NSPI's purchase of natural gas may be priced off of AGT-CG or another index such as Dawn. At the time of the hedging transactions, there was uncertainty with respect to the level of Nova Scotia offshore production, which is typically priced off of AGT-CG or TGP Z6. There was also uncertainty with respect to the in-service date of the Atlantic Bridge pipeline project, which was expected to increase the availability of AGT-CG-priced gas to NSPI. It was also anticipated that a significant portion of the Company's gas supply could be priced off another index price location, primarily Dawn. Dawn gas cannot be effectively hedged using an AGT-CG product, as it is highly correlated with the Henry Hub index and not the AGT-CG index. As a result, Dawn gas can be hedged using NYMEX futures with no additional basis hedge. This uncertainty in the proportion of gas to be priced off of AGT-CG resulted in NSPI lowering its hedging targets for AGT-CG basis volumes.

The key overall finding here is that NSPI's combination of operational, physical, and financial hedges provided only a partial hedge, not a full hedge, of the daily, physical natural gas prices NSPI knew it would pay for physical natural gas during December 2017. To demonstrate this, we provide the following proof.

Recall that NSPI's financial hedge contracts totaled [redacted] for the Henry Hub and [redacted] for the AGT-CG basis. The way these two contracts worked is as follows. On the day of procurement, NSPI paid a fixed price for the contract, which specified a fixed daily quantity. Taking the Henry Hub futures contracts as an example, NSPI paid an average price of [redacted].[54] NSPI paid [redacted] at the time it entered the contracts—that is, [redacted] for [redacted] for 31 days.

The contract allowed NSPI to lock in a price for Henry Hub gas for December 2017, which would vary between the time of the hedge contracts' execution and the expiry date of November 30, 2017. Upon expiry, NSPI's hedge contracts would settle by paying NSPI the actual, first of month December 2017 monthly price for gas—whatever it turned out to be—for all [redacted] for all 31 days. In this case,

[54] NSPI's handling of the financial hedge of the AGT-CG basis worked the same way as the Henry Hub hedge contract.

the price of natural gas fell to $3.074/MMBtu at the time the contract settled resulting in a payment to NSPI of [redacted]. Figure XII-21 summarizes the mechanics of NSPI's financial hedges.

Figure XII-21. Summary of December 2017 Futures Contracts

	MMBtu/Day	NSPI Paid	Total Payment	NSPI Received	Total Receipts	Difference
Henry Hub	[redacted]					
AGT Basis						

There are two important points regarding the [redacted] in proceeds from the settlement of the Henry Hub hedge contracts. First, while this represents a "loss" of [redacted] on the initial cost of the hedge contracts, it is not a negative finding. The purpose of a hedge is not to make money, but to reduce price risk exposure, which these contracts would have been able to do. Second, the implication of a [redacted] December 2017 settlement price meant that fixed-price physical gas for the month of December was priced close to [redacted] at Henry Hub. Therefore, NSPI's proceeds from the financial hedge contract would have been sufficient to purchase [redacted] for December 2017, ignoring transaction costs. When the proceeds from settling the contracts were combined with the "loss" on the futures contracts, the effective price for December would have been [redacted]; that is, [redacted]. NSPI also had [redacted] of AGT-CG basis contracts, which settled at [redacted], for a total AGT-CG cost of [redacted]. Once this financial hedge settled, however, NSPI had no further financial contract protection against variations in daily natural gas prices. NSPI neither had, nor entered into, a physical, fixed-price, monthly contract for natural gas at AGT-CG prices; rather, NSPI had only [redacted] of physical, must-take gas contracts that settled on daily December prices, while any additional needed gas would be purchased each day at daily prices.[55] NSPI's ability to resell that gas was a partial hedge (as proven by the loss that it took on the gas that it sold during December 2017). And NSPI's operational hedge provided by Tufts Cove's fuel-switching capabilities was limited by the physical availability of the fuel-switching capability and also by the price of HFO, which is variable, not fixed. Therefore, while the now-settled monthly financial hedge contracts provided some insulation from overall natural gas prices for NSPI's December 2017 gas needs, and the physical resale option and fuel-switching option provided additional limited protection, NSPI was still subject to daily price exposure.

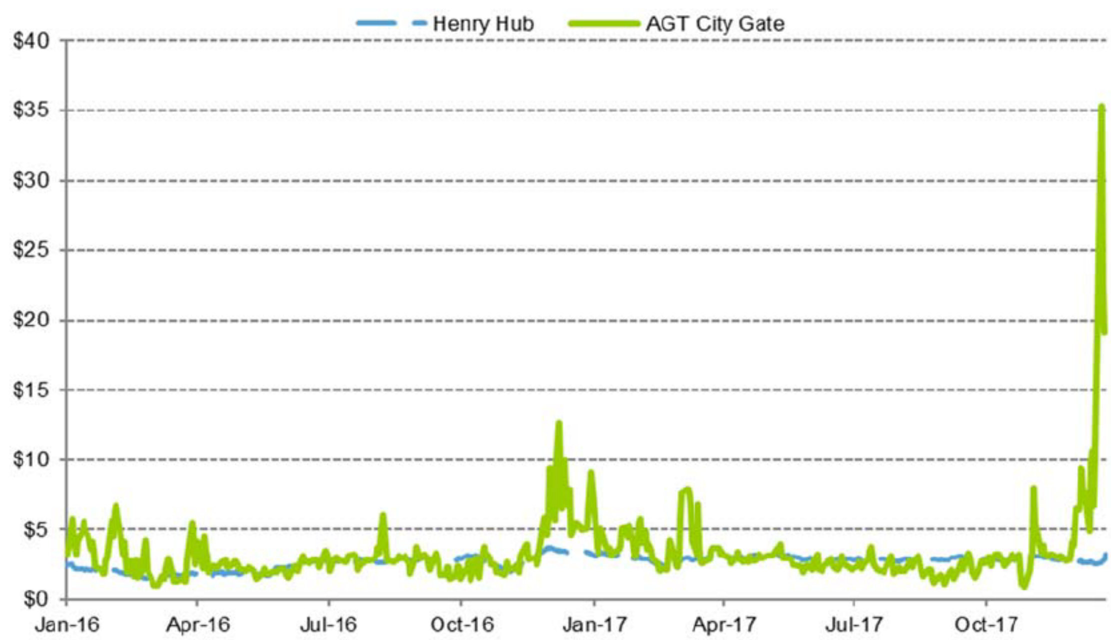
In terms of compliance with the Fuel Hedging Plan, we note that NSPI had discretion to determine whether to hedge daily or monthly natural gas prices. While the Fuel Hedging Plan did recognize products that could be used to hedge daily prices (e.g., swing swaps), it did not prescribe a specific approach and left NSPI to decide how best to hedge its price exposure. During the Audit Period, we observed that NSPI recognized that there was a mismatch between its reliance on physical gas priced on a daily index basis and its use of financial hedge contracts that settled on a monthly price. NSPI's analysis

[55] Both contracts, however, did offer NSPI the option to re-sell any or all of the physical gas received under the contracts, which provided some protection against higher natural gas prices.

focused on historical price relationships between the first-of-the-month price and the daily prices, as well as overall forecasted price expectations for natural gas.

In the case of December 2017, it was not the Henry Hub prices, but the AGT-CG prices that were volatile. Thus, NSPI's proceeds from the AGT-CG financial contract turned out to be insufficient to cover the basis differential associated with its daily gas purchases over the course of December 2017. As shown in Figure XII-22 below, daily prices at the Algonquin City-Gates hub soared to over $33/MMBtu, while prices at Henry Hub remained flat. At the time NSPI's hedges expired, and consistent with the price incorporated in the hedges, December 2017 gas prices were anticipated to be just $5.80/MMBtu, meaning NSPI was exposed to the high prices that were seen in the latter part of the month.

Figure XII-22. Natural Gas Spot Price at Henry Hub and Algonquin City Gates, Daily 2016 and 2017, $/MMBtu



The result of these price spikes in December 2017 was that NSPI spent an additional estimated [redacted] on gas than it would have spent had it fully hedged its December 2017 position either by purchasing physical gas at a fixed price or by entering into swing swaps, which are financial contracts that settle the daily prices for gas against the first-of-the-month price. The [redacted] is equal to the difference between the estimated cost of hedging gas and the actual cost of gas under the [redacted] contracts. Under these contracts, the cost was known and calculated as the actual, weighted-average cost of gas delivered to AGT-CG during December 2017. For purposes of this analysis, the cost of gas was assumed to be equal to the first-of-the-month of $5.95/MMBtu for AGT-CG. However, gas delivered under [redacted] contract was priced off the TGP-Z6 price index. Therefore, to equate the delivered cost of the hedged gas to the actual delivered cost of gas, additional costs, estimated at [redacted], were added to the cost of the hedged gas. This amount captured both the difference between the AGT-CG and TGP-Z6 prices for the [redacted] quantities and the weighted-average adder cost for each contract [redacted] and [redacted], respectively). The calculation of the [redacted] is shown in Figure XII-23 below.

Figure XII-23. Estimated Cost of Not Fully Hedging Gas Prices in December 2017[56]

		Costs $US/MMBtu	Previously Hedged Volume (MMBtu)	Days	Total $US
		a	b	c	d = a x b x c
Cost of Gas in December 2017					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted] [redacted]	[redacted]
Estimated Cost of Gas with Hedge					
Estimated Cost of Gas at AGT	2	[redacted]			
Basis Difference TGP-Z6 and AGT	3				
Estimated Cost of Delivered Gas	4 = 2 + 3				

To limit its exposure to changes in the price of natural gas during December 2017, NSPI could have purchased fixed-price, natural gas contracts or swing swaps. For the former, NSPI has historically purchased only a limited amount of gas on a fixed price basis, and never for the winter months. Regarding the latter, NSPI considered swing swaps, but concluded that for the Algonquin basis they were illiquid products and thus would be unsuitable purchases.[57] Moreover, NSPI noted that its dual-fuel capability at Tufts Cove allowed for an inherent operational hedge against high gas prices and that the Fuel Hedging Plan required NSPI to exercise those operational hedges before entering into financial hedges.[58]

NSPI's decision making over the Audit Period as it relates to December 2017 natural gas physical purchasing and hedging—despite the negative results caused by the high daily natural gas prices—was in line with the Board-approved Fuel Hedging Plan. First, with respect to NSPI's decision to let the financial hedges expire on November 30, 2017, and receive financial settlement, we note that the Fuel Hedging Plan clearly states:

> Except where justified and documented in advance, **all swaps that [NSPI] enters will be financially settled, as is industry standard.** All exceptions require approval prior to hedge execution, by all the required Front, Middle and Back Office groups, with

[56] This analysis does not take into account the impact of losses incurred on the reselling of gas.

[57] Note that NSPI in response to its August 2017 RFP [redacted].

[58] Fuel Hedging Plan, page 23.

> documentation of the purpose of the physically-settled swap, the risk evaluation of that swap and the required approvals. [59] (emphasis added)

Thus, NSPI managed its financial hedging contracts appropriately.

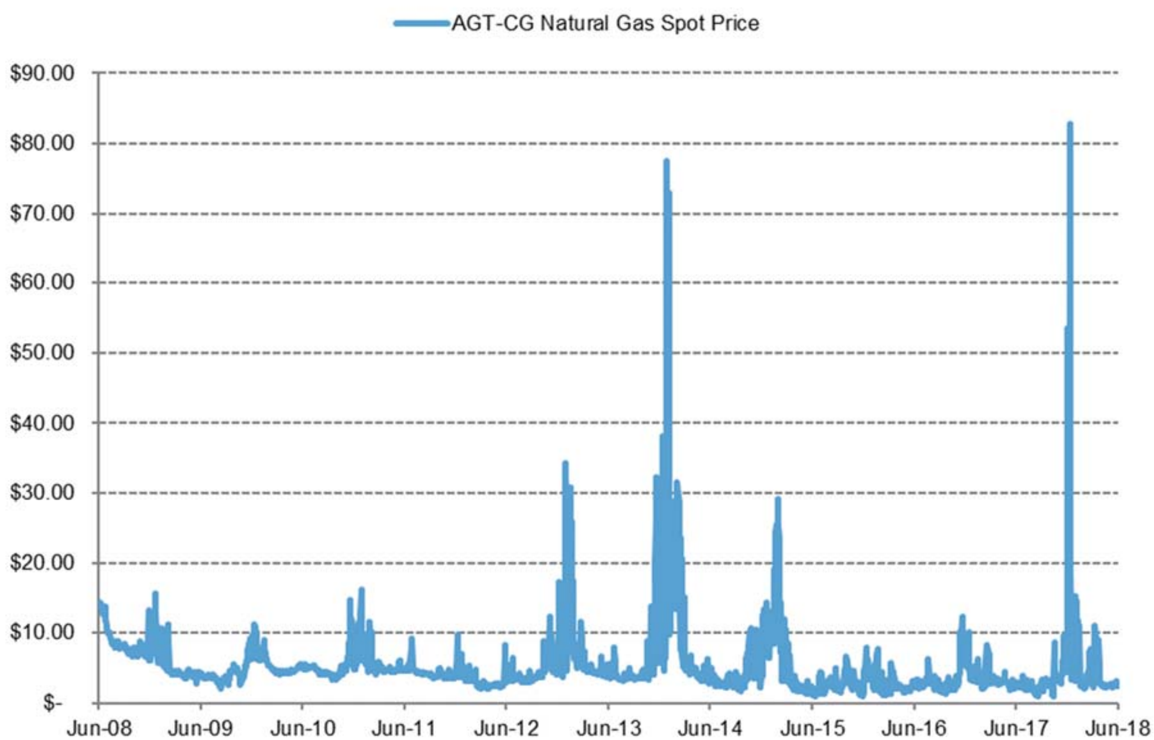
Second, while the Fuel Hedging Plan recognizes that a reasonable way to hedge NSPI's natural gas price exposure is to enter into financial hedges that settle on the Henry Hub and AGT-CG basis prices, it does not prescribe whether NSPI should hedge daily or monthly prices. [60] That is left to NSPI's discretion. Here, we find NSPI's analysis of the costs and benefits of its hedging options for December 2017 to be both in line with the Fuel Hedging Plan and reasonable. NSPI clearly sought to use its operational hedge before entering into any financial hedging contracts and credibly assessed the viability of using financial hedging products that settle on a first-of-the-month basis to hedge daily gas prices.

Third, it must be noted that the AGT-CG price results for December 2017 were unusual but not unprecedented. Similar spikes in the AGT-CG price were seen in the winter of 2013–2014, as shown below in Figure XII-24. While NSPI's analysis included historical prices back to 2013, NSPI assumed that on days of very high natural gas prices, HFO would be economic, and NSPI would switch from using natural gas to HFO. Moreover, on days when natural gas was economic, NSPI noted that, on average, the monthly settled price was *higher* than the average of the daily prices in the winter months over the three years ending 2016, suggesting that using first-of-the-month financial hedges would be sufficient to hedge daily gas prices.

[59] Fuel Hedging Plan, page 7.

[60] Fuel Hedging Plan, page 11.

Figure XII-24. AGT-CG Natural Gas Prices since 2008, $/MMBtu



Fourth, with respect to NSPI's decision to enter into physical contracts based on a daily price index, it appears that it was motivated by a desire to reduce the cost of gas, while protecting against price blowouts through the operational oil options and the ability to sell must-take gas. Nevertheless, AGT-CG prices can be highly volatile and have reached prices much higher than those observed in December 2017. Rather than fully hedging its exposure to natural gas prices, NSPI exercised its own judgment regarding natural gas price expectations to determine the extent of its natural gas hedging transactions.

While we find that NSPI's decision making was in line with the Fuel Hedging Plan and was based on reasonable analysis, we feel it is necessary to point out two potential issues for the Board to consider going forward.

First, under the Fuel Hedging Plan, NSPI bases its decision on whether to enter into a hedge transaction, in part, on the proposed transaction's impact on VaR. Per the Fuel Hedging Plan, in calculating VaR, the volatilities and correlations are calculated using a 90-day historical time period. However, the Fuel Hedging Plan does not provide any additional detail regarding the nature of that 90-day historical time period. We found that in practice, NSPI appropriately uses 90 days of forward prices.

Second, the example of December 2017 is a useful example of (1) the complexity of NSPI's hedging activities and (2) the policy decisions inherent in a Fuel Hedging Plan like NSPI's. As we noted, the size of the price spikes observed in December 2017 relative to the monthly price at the beginning of December was unusual—but not unprecedented. The policy question then becomes, do NSPI and the Board wish to protect against such low probability events? And if so, at what cost? By having discretion in the Fuel Hedging Plan regarding the use of partial hedges (operational, physical, and financial, as described in this section), NSPI is essentially making decisions based on speculation—even if that speculation is based on quantified, reasonable data analysis. Removing that discretion would require NSPI to fully hedge its gas positions; however, due to the potential illiquidity in fixed price physical contracts and/or daily financial gas hedges (i.e., swing swaps), this approach could have high transaction costs. Because the Fuel Hedging Plan is approved by the Board, NSPI must follow its dictates, and the Fuel Auditor must assess NSPI's compliance accordingly. Here again, NSPI met its requirements under the Fuel Hedging Plan. The fact that despite doing so, NSPI remained exposed to such real-time price events could argue for reconsideration of some of the underlying policies manifested through the Fuel Hedging Plan. Such a question is outside our scope.

XII.B.4. Liberty's 2014–2015 Recommendations

In its report for the prior audit period, Liberty offered two hedging-related recommendations. First, while noting the positive changes made to the natural gas hedging program, Liberty noted that an effectiveness measurement component had not been formally adopted and recommended that NSPI adopt one.[61] Second, it noted that there was insufficient documentation of efforts to find the best prices for hedging transactions and thus recommended an internal audit to review the process that FERM's traders use to place trades for hedging and periodically test the sufficiency of efforts to seek the best price. [62]

With respect to the recommendation to develop a measurement of hedge effectiveness, NSPI agreed with this recommendation,[63] and we find that NSPI has adequately addressed this recommendation. NSPI has developed quarterly "hedge effectiveness reports," which contain several metrics for the judgement of NSPI's hedging activity effectiveness. The Fuel Hedging Plan contains an appendix (Appendix E: Reporting) and requires the dissemination of the hedge effectiveness report to CROC,[64] while NSPI also presents its reports to the FAM SWG.

NSPI also agreed with Liberty's second recommendation[65] and commissioned an internal audit of the execution of fuel hedging financial trades with the results published in August 2017. The internal audit identified several areas where the processes to support the execution of financial trades for the purposes of hedging fuel costs required improvement, including the processes in place to confirm traders seek reasonable prices for hedging transactions, reporting processes to monitor trade execution process and

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61 Audit of NSPI's FAM 2014-2015, pages II-16 and II-17. Conclusion #4 stated: "[NSPI] has made sound changes to natural gas hedging program design and implementation, but has not formally adopted an effectiveness measurement component." Liberty's recommendation stated that "[NSPI] should perform regular assessments of hedging program performance."

62 Audit of NSPI's FAM 2014-2015, page V-22 and V-23. Conclusion #7 stated: "There was during the Audit Period insufficient documentation of efforts to find the best prices for hedging transactions." Liberty's recommendation stated: "Conduct Internal Audit reviews of the process the FERM's traders use to place trades for hedging, and periodically test the sufficiency of efforts to seek best price."

63 NSPI FAM Audit Action Plan, July 31, 2017, page 12.

64 It should be noted that the Fuel Hedging Plan was in progress but approved subsequent to the Liberty 2014–2015 audit.

65 NSPI FAM Audit Action Plan, July 31, 2017, page 14.

processes to confirm periodic reporting of plan performance and compliance to the oversight authorities including FST and CROC.

In response to the internal audit's findings, NSPI management indicated that it would provide a detailed action plan by September 30, 2017. We reviewed the action plan, which included the following issues related to hedging:

- [redacted] is included in the 2017 Fuels Incentive Design. In addition, the Fuels Incentive rewards for successful completion of an internal audit (overall rating in one of top two categories and no items scored as "Not Acceptable").

  The audit found that a potential conflict of interest existed for FERM staff responsible for compliance and reporting because their compensation was based on hedging results. Further, it was stated that providing compensation based on meeting predetermined internal audit results might negatively impact the relationship between management and internal audit staff.

  Remediation: NSPI recommended that the Director of Fuels work with human resources to develop an alternative compensation scheme that complies with the internal audit's recommendations.

  NSPI has indicated that this work was completed in the early part of 2018. We did not request specific information on the alternative compensation scheme and incentive measures, and no additional information was provided beyond the work that was completed.

- **Audit Issue No. 2017-Q3-2:** For OTC trades, market information at the time of trade execution is not consistently retained to confirm that traders seek reasonable prices for hedging transactions.

  Remediation: NSPI's remediation plan requires that when executing an OTC trade, a screenshot(s) of market information and/or other applicable information used to make a decision to execute the trade be retained. In addition, documentation for the prior quarter is to be reviewed and confirmed as available.

  NSPI has responded to the concerns raised in the above issue, and the actions taken have adequately addressed the issues.

- **Audit Issue No. 2017-Q3-3:** Processes are not in place to validate that trades were executed in accordance with recommendations approved by the FST.

  Remediation: A new hedging execution reconciliation process was established that requires the Manager, Fuels Reporting and Compliance to provide hedging FST approvals to the Middle Office as they occur and, where possible, to indicate the timetable for execution. The Middle Office is to reconcile the hedge recommendations approved by FST to transactions executed by the Front Office and entered into Allegro. Any exceptions are to be reported to the FST and CROC.

NSPI has responded to the concerns raised in the above issue, and the actions taken have adequately addressed the issues.

- **Audit Issue No. 2017-Q3-4:** Quarterly reporting to the FST and CROC does not include certification that all hedging transactions were in compliance with the approved Fuel Hedging Plan. In addition, explanations for any deviations from the current Fuel Hedging Plan are not highlighted.

  Remediation: NSPI recommended increased reporting requirements and inclusion of the Hedging Plan Reporting requirements in the Fuel Manual and Fuel Manual Compliance Program. In addition, a review of all 2017 Q4 reports (as outlined in the Hedging Plan) and all FST Agenda/Minutes be conducted by the Manager, Fuels Reporting and Compliance to ensure they were in compliance with the Fuel Hedging Plan. This review is to be conducted annually.

NSPI has responded to the concerns raised in the above issues and the actions taken have adequately addressed the issues.

XII.C. Conclusions

Conclusion XII-1: The hedging program as executed during the Audit Period conformed with the objectives of the EPIA and requirements of the plans in place during the period, and, in particular, the Fuel Hedging Plan.

Conclusion XII-2: There exists a question as to whether NSPI's stated objective of "minimizing the probability of a significant cumulative under recovery of fuel costs at the end of the Rate Stability Period" to limit rate increases in 2020 is required by Board Order. However, minimizing either an over- or under-recovery of fuel costs is the ideal. It is to be noted that as a result of the hedging program, over the first year of the RSP, the cumulative balance (over recovery) has been increased as a result of the hedging program.

Conclusion XII-3: Our review shows that NSPI conducted quarterly rebalancing activities consistent with the requirements of the Fuel Hedging Manual. The quarterly rebalancing used updated fuel consumption forecasts from PLEXOS that informed the need to enter into additional hedges or unwind existing hedges to remain in compliance with the Fuel Hedging Manual during the RSP.

Conclusion XII-4: Prior to the RSP, the hedged quantities of solid fuels and natural gas were largely consistent with the standards in place at the time. For that portion of the Audit Period during the RSP, the quantities of solid fuels, natural gas, power, and fuel oil hedged were largely consistent with the requirements of the Hedging Plan. Variances from targeted amounts, where they existed, were explained, and actions taken to rebalance positions were initiated where warranted and when suitable liquid product was available to undertake the required transactions.

Conclusion XII-5: For that portion of the Audit Period within the RSP, the hedging program has resulted in a significant decrease in the value at risk at the portfolio level. This has been achieved at a low cost.

Conclusion XII-6: NSPI's processes for hedging as found in the Fuel Manual Revision 10, Link 6, "Solid Fuel Portfolio Process, Fuels, Energy & Risk Management," Table 1, appear to be in conflict with the guidelines of a target hedging range of [redacted] of forecast consumption set forth on page 4 of the Fuel Hedging Plan. The Fuel Manual needs to be edited to align with the Board-approved Fuel Hedging Plan and the relationship between the two documents clarified. (Recommendation)

Conclusion XII-7: Regression analysis conducted on two portfolios calculated in Allegro—(1) a hedge portfolio containing all hedges (physical and financial) for the forward balance of the RSP and (2) a forecast consumption portfolio containing all forecast consumption for the same time period entered in the system as short positions—provides regular information on the effectiveness of the hedging program. The results indicate the program is effective at a portfolio level.

Conclusion XII-8: Assessments of the individual hedges through price regressions provide trade-specific information on the effectiveness of the program. In all quarters of the Audit Period, the percentage of effective hedges consistently exceeded 90%.

Conclusion XII-9: NSPI has access to [redacted] possible counterparties through ISDA Master Agreements, many of which NSPI transacted with during the Audit Period.

Conclusion XII-10: Analysis of VaR at the individual fuel level indicates significant reductions in risk, particularly for the solid fuel program.

Conclusion XII-11: The analysis of NSPI's natural gas trading, hedging, and operational activities in December 2017, during which natural gas prices spiked sharply, indicated that NSPI acted reasonably and consistently with the Fuel Hedging Plan.

Conclusion XII-12: The December 2017 analysis shows that NSPI exercised its operational hedge afforded by the fuel-switching capability at Tufts Cove. That is, as the price of natural gas spiked, natural gas consumption at Tufts Cove dropped sharply. However, the value of this operational hedge is limited by the availability of the units to switch from gas to HFO on a timely basis. This suggests a need for quantification of the value of that operational hedge in making hedging decisions. (Recommendation)

Conclusion XII-13: The Fuel Hedging Plan recommends hedging Henry Hub and AGT-CG, but the available hedging instruments (NYMEX for Henry Hub and IFERC for AGT-CG) settle off first-of-the-month (FOM) prices while NSPI purchases physical gas on a daily price basis. Though NSPI is authorized to use physical and financial contracts to address this daily risk, there is no policy outlined within the Fuel Hedging Plan to address this mismatch between FOM and daily prices. How (or if) the mismatch is hedged is up to NSPI's discretion, a policy decision inherent in the Fuel Hedging Plan that can expose NSPI to daily natural gas price risk.

Conclusion XII-14: NSPI appropriately uses 90 days of forward prices to evaluate VaR. (Recommendation)

Conclusion XII-15: NSPI has addressed Liberty's recommendations with respect to NSPI's hedging program.

- NSPI has developed quarterly "hedge effectiveness reports" that contain several metrics for the judgement of NSPI's hedging activity effectiveness at the portfolio, fuel, and individual hedge level. In addition, the Fuel Hedging Plan requires the dissemination of these reports to CROC. NSPI also presents its reports to the FAM SWG.
- NSPI conducted an internal audit as recommended. That audit identified several areas where the processes that support the execution of financial trades for the purposes of hedging fuel costs required improvement, including the processes in place to confirm traders seek reasonable prices for hedging transactions, reporting processes to monitor trade execution process, and processes to confirm periodic reporting of plan performance and compliance to the oversight authorities including FST and CROC.

XII.D. Recommendations

Recommendation XII-1: Revise and/or clarify Table 1 of Link 6 "Solid Fuel Portfolio Process" of the Fuel Manual to be consistent with the Fuel Hedging Plan.

Recommendation XII-2: NSPI should quantify the all-in cost of the HFO hedge at Tufts Cove, including how quickly the generator can switch from gas to HFO, and the cost of unplanned gas burns at Tufts Cove when HFO is less expensive than gas. These are all costs associated with the HFO hedge and should be compared to NSPI's other hedging options, such as the expected costs of buying either fixed price monthly gas or financial swing-swap contracts, when making hedging decisions.

XIII. FAM Accounting[1]

XIII.A. Background

A 2009 NSUARB order approved the implementation of NSPI's FAM. The FAM provides for an annual adjustment to recover fuel and purchased power costs on a more current basis, in order to address the effects of volatile fuel and energy costs. The FAM reconciles the differences between actual and base fuel and energy costs. Two deferral accounts drive annual changes in the costs recovered from customers through the FAM:

- **The Actual Adjustment:** Tracks the difference in current fuel and energy costs from those reflected in the base cost of fuel or actual adjustment; and
- **The Balancing Adjustment:** Compares costs actually recovered through Actual Adjustment to those intended to be recovered.

The difference between current costs and recoveries accrues carrying charges, which form part of the reconciliation of actual and base costs.

The scope of our FAM accounting review for 2016 and 2017 (Audit Period) included:

- FAM accounting policy and procedures
- Actual fuel and purchased power costs recorded in general ledger accounts, as provided for under the approved POA
- Difference between actual fuel and purchased power costs and those recovered under base rates.

XIII.B. Findings

XIII.B.1. FAM Accounting—Fuel and Purchased Power Cost

We reviewed NSPI's financial accounting process and inspected detailed financial accounting records that support the actual cost of fuel and purchased power claimed. We conducted an on-site

[1] This chapter was primarily authored by Horne, LLP and reviewed by Bates White.

review to examine documents and supporting work papers and to discuss processes, procedures, systems, documentation, and FAM reporting with NSPI personnel.

We sampled hundreds of accounting entries from January 2016 through December 2017 and performed test procedures on selected entries that included related supporting accounting documents. We also reviewed organization charts, charts of accounts, cost-center and project activity codes, general policies, and procedures. We examined accounting process flowcharts related to fuel and purchased power procurement, energy marketing documents, and supporting accounting information pertaining to the FAM's cost components. We interviewed NSPI's Manager of Fuels Accounting and Reporting and other individuals responsible for creation and maintenance of accounting records and for preparation of monthly, quarterly, and annual FAM reports, statements, and supporting documents.

We sought to determine whether NSPI maintains its FAM accounting and reporting information in a manner sufficient to facilitate a level of verification and auditing customary in the administration of clauses such as NSPI uses, and that regulators oversee. Our review addressed FAM accounting issues identified in prior reviews, e.g., mark-to-market (MTM) accounting for solid and liquid fuel transactions.

XIII.B.2. Accounting Resources for FAM Administration

The POA serves as the principal governing document for FAM accounting. This plan sets forth the policies and procedures guiding FAM calculation and determining allowed costs. NSPI also employs other accounting policies and procedures that have relevance to fuel and purchased power costs. They provide the administrative and accounting procedures that ensure that costs have been reasonably and accurately reported. We found NSPI's accounting personnel to be knowledgeable, helpful, and open about FAM accounting and reporting processes and familiar with the detailed, supporting work papers.

NSPI continues to maintain a formal accounting flow chart and operates under a clear chain of reporting in those organizations responsible for FAM-related accounting activities. These organizations include the Controller, Fuels Planning and Performance, and Fuel Accounting and Reporting.

A formal POA continues to contain the necessary supporting procedures and accounting and reporting checklists. NSPI also maintains appropriate accounting policies and procedures that adequately address accounting for fuel and purchased power expense.

The systems and tools that NSPI uses for fuel and energy accounting and reporting include an appropriate overall accounting system and an appropriate chart of accounts, which have numbers and definitions sufficient to define adequately the accounts, activities, cost centers, and project codes necessary for FAM operation and calculations. NSPI uses an Oracle Accounting System to maintain its general ledger. Aligne operates as a sub-ledger for fuel inventories that interfaces with Oracle. Allegro is also a subledger uses in fuels, purchased power, hedging and nature gas that interfaces with Oracle. NSPI uses MS Excel worksheets to perform variance reporting in key areas of sales information, foreign exchange, and other related fuel and purchased power activity.

We found NSPI's accounting and reporting organizational structure and staff suitable for FAM accounting and administration purposes. Further, we found that the accounting department exercised reasonable oversight and direction of its staff.

XIII.B.3. FAM Reports to the NSUARB

The general context of the accounting resources, including the FAM tools and administration described above, provide the backbone information used to compile the monthly/quarterly/annual FAM reports submitted to the Board. NSPI prepares these reports under process checklists to which its personnel adhere. NSPI continues to maintain a formal FAM in-house review and approval process. The process provides for a stepped level of review by key personnel, who review and comment on the draft monthly/quarterly/annual FAM filings to be submitted to the Board.

XIII.B.3.a. FAM Accounting Policies and Procedures Verification

We tested and verified NSPI's FAM accounting policies and procedures that underlie fuel and purchased power costs reported for the Audit Period. This portion of our work included testing of transactions in various months of the Audit Period.

We requested and received copies of NSPI's general accounting policies and procedures and process flowcharts for fuel and purchased power procurement and inventory, as well as energy marketing.

NSPI's updated documents did not reflect effective dates, making it difficult to determine when they applied. Process and procedure documentation should reflect those complexities and their unique elements.

XIII.B.4. Fuel and Purchased Power Accounting Verification

As it has done before, NSPI continued to maintain vendor master files and adhered to organization and authority approval levels for fuel and purchased power procurement. Data from purchase requisitions, purchase orders, and contracts effectively flowed through Aligne, Allegro, and Oracle as required. The data included contract change authorizations. Monitoring includes cross checks and provides for reconciliations and any necessary adjustments.

Our review and testing of fuel procurement, invoicing, and verification processes demonstrated conformity between costs contracted and costs paid.

Our review of the Chart of Accounts and definitions identified account designation, activity, cost center, and project codes related to FAM fuel and purchased power costs. We obtained detailed general ledger activity within Oracle for each FAM account listed in the POA and for other accounts affecting the FAM. We tested a sample of January 2016 through December 2017 activity by tracing activity to the sub-ledger, original adjusting, and accrual entries, and to supporting work papers. We found no exceptions with the costs reported.

We reviewed the interfaces between Aligne, Allegro, and Oracle. We traced, cross checked, and reconciled information on a sample basis. This work disclosed no issues for concern.

XIII.B.5. Fuel Master Agreements and Purchase Order Controls Verification

Our review and testing of fuel procurement, invoicing, and verification processes did not disclose any instances where costs paid for fuels procured exceed contractually agreed upon prices. We tracked and compared master agreement information maintained within the Fuel Energy and Risk Management department with data from Fuel Accounting. We encountered no difficulties in getting clear and concise information on master agreements.

The purchase order numbers assigned to agreements change annually. However, some agreements remain in effect for longer than a year. Moreover, some vendors have multiple agreements with NSPI. Invoices accurately reflect the annually assigned purchase orders.

XIII.B.6. FAM Process Accounting Controls Verification

Since the last Audit Period, NSPI's accounting department generally has continued to rely on the same activities and reporting checklists when preparing monthly FAM accounting support for FAM filings. We reviewed and tested the overall accounting controls to verify that they support thorough and accurate FAM cost reporting. We found the senior- and manager-level accounting staff to be appropriately engaged in the review and oversight process. Their activities include documented sign-offs of necessary accounting documents.

We selected a sample of different types of fuel transactions, including solid fuel, purchase power, liquid fuels, and MTM transactions from the audit period January 1, 2016, to December 31, 2017, for testing of FAM-related accounting controls related to the purchase and recording of fuel costs. We obtained supporting documentation related to the transactions and ensured controls were operating effectively during the period. During these testing procedures, we identified one instance where a control was not operating effectively for the proper approval of payments with respect to costs flowing to the FAM. (See our recommendation below for details.)

XIII.B.7. Accounting System Flexfield Codes

NSPI's Chart of Accounts includes information that describes its fourteen-digit "Accounting Flexfield" code system. This five-segment system allows for unique identification by company, account, activity, cost centers, and project. We reviewed the consistency of cost classification by reviewing detailed general ledger account activity information, testing transactions on a number of the major cost elements, testing related adjusting entries and supporting data, and reviewing additional supporting details.

Our examination disclosed no reason for concern about the consistency of the classification of costs within the appropriate accounts, nor did it disclose any material differences between underlying FAM costs recorded and those reported. NSPI's accounting system, including supporting work papers, provided sufficient and reasonable transparency for analyzing costs associated with the various FAM cost elements. NSPI's work papers and supporting documents supported the ability to query and extract information from systems.

XIII.C. Conclusions

Conclusion XIII-1: NSPI applies suitable accounting resources, systems, tools, and methods to FAM administration. NSPI provides reasonable oversight and direction of accounting for fuel and energy transactions affecting FAM operations. Personnel in the fuel procurement and accounting departments exercised reasonable oversight and direction of staff in performing activities related to the FAM administration.

Conclusion XIII-2: Fuel and purchased power accounting is generally sufficient. NSPI's accounting system for solid and liquid fuels and for natural gas employs Aligne, Allegro, and Oracle, along with stand-alone MS Excel spreadsheet analysis. Supply contracts are set up and maintained in the inventory master file in Aligne and data from the PI system feeds Aligne. This system automatically calculates the weighted-average unit cost of inventory used to record consumption. The spreadsheets process gas and power revenue, purchases, receivables, and payables.

Conclusion XIII-3: All related fuel and purchased power costs (solid and liquid fuels, gas and purchased power, and MTM, for example) included in the FAM are supported by detailed documents and a review process that includes controlled accrual and adjusting entries. Our review and testing found them to be consistently and appropriately applied.

Conclusion XIII-4: Our review of fuel purchase accounting also included proper approval of payments over fuel purchases. The process for approving payments is summarized in the Fuel Manual and includes a monetary threshold hierarchy for approval. During our testing of fuel purchase transactions, we found one exception where proper approval for payment was not obtained. We subsequently expanded our sample of fuel purchase transactions and found no additional exceptions.

Conclusion XIII-5: There may be opportunity to improve document retrieval and controls, which are generally effective. Specifically, we noted difficulties in the ability to promptly provide information on contract terms and conditions.

Conclusion XIII-6: Our review and testing of the procurement, invoicing, and verification processes did not disclose any situation where costs actually paid for fuels procured exceeded agreed upon prices.

XIII.D. Recommendations

Recommendation XIII-1: Update accounting policies and procedures to incorporate process narratives and effective dates. In general, policies direct team members to take action consistent with prescribed accounting organizational requirements, and procedures provide the necessary related instructions. Policies and procedures change from time to time; therefore, it is important that those individuals who rely on them have a clear understanding of their effective dates so that changes are properly implemented at the right time. Such narratives and effective dates will also ensure that external users (e.g., auditors and consultants) have a similar understanding.

Recommendation XIII-2: Implement a formal control report schedule that will provide detailed summary information for contracts and approval process. We recommend that the informal internal control sheet prepared by Fuel Accounting, detailing coal contract terms such as, purchase order numbers, contract terms and pricing, as well as verification of appropriate representatives' authorization of such terms be formalized, and include shared oversight and periodic approval of the report by both the fuel procurement and fuel accounting departments. This change will provide assurance that contract terms are readily available, in order to permit monitoring for compliance with contract terms.

Recommendation XIII-3: Revise the Request for Payment form to include required monetary threshold approvals for fuel purchases. We recommend updating the Accounts Payable Request for Payment form to include designated areas for proper approval of fuel transactions based on the monetary thresholds summarized by the Fuel Manual. This procedure will facilitate the proper approval for fuel purchases at the time of payment.

XIV. Board-Specific Issues

In this chapter, we address three issues that were specifically raised by the Board in other proceedings for consideration by the fuel auditor. These issues may have some overlap with other chapters in this report; however, we agreed with Board staff and stakeholders that these issues should be isolated in their own chapter given the Board's interest in our reviewing them. The issues addressed relate to PHP, refurbishment costs at Tufts Cove, and NSPI's approach to internal auditing.

Board Issue 1: Port Hawkesbury Paper

XIV.A. Background

The PHP paper mill takes electric service under a negotiated implementation of the LRT provisions of NSPI's tariff. The LRT Pricing Mechanism, which governs the terms and pricing of service to PHP, is the only current LRT implementation and applies exclusively to PHP. The Board established the LRT provisions of NSPI's tariff in 2000, with the purpose of encouraging companies to continue to purchase service from NSPI rather than pursue alternative supplies.[423] The LRT initially established eligibility based on an assessment of whether a company had the technical ability and economic incentive to purchase any alternative supply (i.e., to build its own cogeneration facility). Eligibility was expanded in 2011 to include circumstances under which "the rate is required to respond to the competitive challenge of business closure due to economic distress,"[424] which is the basis under which PHP's LRT Pricing Mechanism was negotiated and approved in 2012.

The current PHP LRT, which expires in December 2019, establishes a rate for PHP "whereby PHP pays the variable incremental costs of service, plus a significant positive contribution to fixed costs, such that other customers are better off by retaining PHP rather than having PHP depart the system and make no contribution to fixed cost recovery."[425] Specific terms of the PHP LRT are discussed further below.

Subsequent to the 2016 supplementary audit of the PHP LRT, the Board approved an amendment to the LRT to address the pricing of excess redirected imported energy (discussed below) and ordered another audit of the LRT to be conducted as part of the instant FAM Audit.[426]

The Board recently addressed the re-opener provision of the LRT (M08519), which was triggered by the fact that PHP's contribution to fixed costs would be less than $20 million for the five fiscal years to the end of 2017. The Board approved adjustments to several rate components, effective January 1, 2018

[423] The only alternative supply practically available to large loads on NSPI's system would be cogeneration facilities.
[424] NSPI Tariffs, January 1, 2017, page 39.
[425] *Id.,* page 44.
[426] Order, 2017 NSUARB 8, M05803, January 23, 2017.

(after the Audit Period), and affirmed the $4.00/MWh cap on PHP's contribution to fixed costs for the remaining two years of the LRT term.

The remainder of this section presents the results of the LRT review and certain observations related to the potential renewal of the LRT following expiration of the current tariff in December 2019.

XIV.B. Findings

XIV.B.1. The LRT Pricing Mechanism and Implementation during the Audit Period

The LRT Pricing Mechanism establishes the terms and pricing of service provided to PHP. In addition to setting out how the costs charged to PHP are to be determined, the PHP LRT addresses communication between NSPI and PHP regarding anticipated energy costs and load levels, PHP access to imported energy, PHP's load reduction obligations and applicable penalties for non-performance, and other terms and conditions.

XIV.B.1.a. Pricing Components of the PHP LRT

The LRT Pricing Mechanism defines the pricing components used to determine charges for net energy consumed by PHP. These components, and the respective rates during the Audit Period, where specified explicitly, are (presented in $/MWh terms):

1. Hourly incremental cost of energy consumed, determined by the "differential method," described further below, including
    a. Variable operating cost at $1.50/MWh (also referred to in reporting as VOM)
2. Variable Capital Cost at $1.17/MWh
3. Fixed Cost Contribution at $2.00/MWh
4. Additional Fixed Cost Contribution of 18 percent of PHP's net earnings before tax, capped at $4.00/MWh (and to include the Fixed Cost Contribution of $2.00/MWh)
5. Administration Fee of $20,700 per month.

The hourly incremental cost of energy consumed by PHP, which makes up the large majority of the total amount NSPI billed, is determined by a differential cost methodology, which aims to capture the actual impact of PHP load on NSPI's system cost compared to the cost if PHP load were not present. While the concept is easily stated, there are number of complexities in the methodology and billing processes, some of which stem from other arrangements involving PHP, particularly the ability of PHP to request imports on its own behalf, and the option PHP has to request generation from the Port Hawkesbury Biomass facility if NSPI decides not to dispatch the plant. We conclude that the differential cost methodology reasonably captures the short-term incremental cost of PHP load and was generally implemented appropriately during the Audit Period, with one exception relating to imports, addressed below.

XIV.B.1.b. The Differential Cost Method Used to Determine Incremental Cost of PHP Load

For clarity, the differential cost method is applied in two contexts: one to provide PHP with an advance estimate of energy costs it would likely face looking forward if it decided to operate the mill, and another to determine the actual bill to PHP after it has consumed energy. In both cases, the intent is to determine the difference between the NSPI system cost inclusive of serving the PHP load and the NSPI system cost if the PHP load did not occur. The cases capture direct fuel costs, non-fuel variable operating costs, environmental costs associated with coal blending and mercury abatement, and impacts on transmission line losses.

On a daily basis NSPI provides PHP with a day-ahead hourly cost forecast based on two commitment runs of the GenOps model, one with PHP load, based on the business process PHP currently has in place, and one with no PHP load. The cost cases provided to PHP include one representing no PHP load and six additional cases corresponding to different PHP run levels. Unit commitment effects are captured by excluding PHP load in the no-PHP case beginning three days prior to each forecast day and four days after that day.

To determine PHP's actual billed costs, NSPI performs a separate series of GenOps model runs at the end of each weekly billing cycle, using information on actual loads, fuel costs, generator performance, and interchange flows. The unit commitments determined in the forecast runs (both with and without PHP) are used in the after-the-fact billing runs. The after-the-fact "with PHP" case incorporates actual unit dispatch levels. For the after-the-fact "without PHP" case, the counterfactual dispatch is optimized by the mode. The differential in cost between the two after-the-fact model cases establishes the hourly billing to PHP for each billing week.

Bates White reviewed the detailed specification of how the differential cost method is performed and observed the real-time process in which NSPI communicates the advance cost projection to PHP and then determines generation commitment and dispatch. We conclude that the differential cost method is a reasonable method for determining the incremental cost of PHP load and, in particular, that the method appropriately accounts for effects on unit commitment, not just marginal generation cost. For the GenOps cases without PHP, PHP's load is excluded for three days prior to the day for which the commitment decision is made and for four days after that day. We find that this approach adequately captures the incremental effect of PHP load on NSPI's system commitment.

XIV.B.1.b.i. Manual Intervention in Commitment Process

Our observations regarding the extent of manual intervention by NSPI staff in the unit commitment process (discussed in the Economic Commitment and Dispatch Chapter) also have bearing on the application of the differential cost methodology under the LRT, as the discretionary interventions are reflected in the GenOps model runs to communicate the advance cost information to PHP and to determine after-the-fact billing. We observe no basis to conclude that the manual process has a systematic or inappropriate effect on the costs assigned to PHP, yet we recommend that NSPI establish a more explicit protocol and improved documentation for such manual adjustments, which will improve transparency in administration of the PHP LRT as well as in overall system operation.

XIV.B.1.b.ii. Value of Incremental Line losses

Figure XIV-1 and Figure XIV-2 below summarize the PHP energy and billed costs on a quarterly basis for 2016 and 2017, respectively. One result that stands out is that the total charges to PHP were generally *reduced* for the incremental effect of PHP's load on system line losses. This effect of the differential method of determining incremental cost to serve PHP load was also observed in the 2016 LRT audit, which noted NSPI's explanation that Tufts Cove, located in the Halifax metro area, is often the marginal unit used to serve PHP load, and that by triggering the commitment of this unit, PHP load reduces energy flows from more distant resources to Halifax and consequently reduces overall system losses and costs. This result reflects a consistent application of the incremental cost methodology, given the particular topology of the NSPI system, and the distribution of generation and load. Bates White concludes that the benefit in reduced line losses and costs is a consequence of PHP load and is therefore appropriately assigned as an offsetting component of PHP incremental costs. NSPI has reported to the Board that PHP load has reduced the average system loss factor, which has provided net benefits to FAM customers.

Figure XIV-1. PHP Quarterly Energy and Billed Cost, 2016

			2016		
	Q1	Q2*	Q3	Q4	Total*
Energy, MWh	[redacted]				
Energy Cost, $					
Value of Incremental Line Losses, $					
Environmental Adder, $					
Variable Operating Cost, $					
Fixed Cost Contribution charge, $					
Variable Capital charge, $					
Customer charge, $					
Adjustments, $					
Total Billed, $					
Energy Cost, $/MWh					
Total Billed, $/MWh					

* [redacted]

Figure XIV-2. PHP Quarterly Energy and Billed Cost, 2017

	2017				
	Q1	Q2	Q3	Q4	Total
Energy, MWh	[redacted]				
Energy Cost, $					
Value of Incremental Line Losses, $					
Environmental Adder, $					
Variable Operating Cost, $					
Fixed Cost Contribution charge, $					
Variable Capital charge, $					
Customer charge, $					
Adjustments, $					
Total Billed, $					
Energy Cost, $/MWh					
Total Billed, $/MWh					

XIV.B.1.c. Additional Contribution of PHP to Fixed Costs

The data in Figure XIV-1, which are for 2016, exclude an additional contribution to fixed costs that was billed to PHP in June 2016 that reflects an amount for 2015 (prior to the Audit Period) based on PHP's positive net earnings in that year. This additional contribution was [redacted], which corresponds to $2.00/MWh for 2015 energy consumption and results in a total contribution by PHP for 2015 of $4.00/MWh, the cap under the LRT.

XIV.B.1.d. Accounting for Imports Transacted on PHP's Behalf

Under the terms of the LRT, PHP can access imported energy when such an import is *not* economic for NSPI's other customers. Specifically, the LRT allows PHP access to imports:

- If NSPI receives a response to an energy RFP which it does not intend to accept
- If NSPI receives an unsolicited offer of energy that it does not intend to accept
- If PHP requests that NSPI search the market for a specific volume of energy for a specific period of time and the import is not economic for NSPI's other customers
- If NSPI searches the market for PHP for a specific volume of energy for a specific period of time and the import is not economic for NSPI's other customers.

As discussed in the Power Purchases and Sales Chapter, Bates White determined that PHP pursues a significant number of import transactions under these terms. NSPI entered into import transactions on PHP's behalf in nearly [redacted] of the hours in the Audit Period, representing a total energy volume of [redacted], or approximately [redacted] per import hour on average. The LRT specifies that PHP is responsible for the full cost of any import transaction executed on its behalf, which includes transaction and wheeling fees. NSPI indicates that "PHP is only provided real time (current day, near hours) access to market for short term strips (generally in the 1–3 hour range). Access to the import market is at the sole discretion of NSPI."

As reported in the Power Purchases and Sales Chapter, in a review prompted by a Bates White data request regarding sampled import transactions, NSPI determined that it had erroneously billed FAM customers for [redacted] hours of PHP import transactions, representing a total of [redacted] and had erroneously billed PHP for [redacted] of import transactions executed on behalf of FAM customers, totaling [redacted] The net cost effect of these erroneous billings over the Audit Period was that NSPI undercharged PHP and overcharged FAM customers by [redacted]. NSPI indicated that it would initiate a billing correction and would address the issue in its month-end FAM report. NSPI has introduced new control procedures intended to prevent the errors that caused the erroneous assignment of import costs.

The LRT was modified as of 2017 to change the treatment of excess redirected imported energy. Under the current tariff, when PHP load is not sufficient for NSPI to take an entire import commitment, NSPI will assume the import and compensate PHP at either the cost of the import or the system marginal cost, whichever is less. This method fully shields FAM customers from any negative impact from PHP's inability to absorb the entirety of an import transaction. An additional LRT provision addresses circumstances when NSPI must interrupt a PHP import transaction in order to support system stability, in which case NSPI would compensate PHP at the [redacted] of the ISO New England Salisbury node applicable hourly price.

XIV.B.1.e. Resolution of Negative Energy Cost Hours

The 2016 audit of the LRT noted that in the 2014–2015 period PHP was assigned negative costs in certain hours by the differential cost methodology, because PHP load could reduce wind curtailments under some circumstances. In response to the audit recommendations, NSPI modified the PHP billing so no negative price billing will occur, except that resulting from negative pricing of ISO-New England. The latter circumstance would only occur when PHP had requested an import and an event in ISO-New England caused the energy price to drop below zero unexpectedly. NSPI indicated that this billing modification was implemented in 2016 and was applicable for most of the Audit Period.

XIV.B.2. Realization of the Intent of the LRT and Benefits to PHP

In approving the PHP LRT, the Board determined that PHP met the eligibility criteria for the tariff, and in particular that the paper mill would likely not restart—that is, the load would not be retained—in the absence of an LRT that would provide for energy rates significantly below those available under other existing standard tariffs. At the same time, the Board required that the LRT impose no incremental costs on other NSPI customers and that it ensure a positive contribution by PHP toward fixed system costs. By covering the full incremental cost of serving PHP's load and providing for a contribution to fixed costs, the LRT would arguably leave other customers better off than if the PHP load were eliminated.

Bates White concludes that the PHP LRT has reasonably achieved the intent of the Board during the Audit Period: the load was retained, other NSPI customers did not bear costs to serve PHP load, and PHP made a contribution to fixed costs.

The energy consumption for which PHP was billed during the 2016–2017 Audit Period totaled [redacted] Excluding the additional fixed cost contribution recorded in September 2016, associated with PHP earnings in 2015, the total cost billed to PHP over the two years was [redacted] Based on an analysis of hourly load data, PHP's energy consumption was divided roughly 39% during peak hours and 61% during off-peak hours. The pattern of average hourly load for peak and off-peak periods each month is charted in Figure XIV-3.

Figure XIV-3. PHP Average Hourly Load by Month, 2016–2017

[redacted]

The LRT appropriately assigns to PHP the incremental costs required to serve PHP's load, which also encourages efficient energy use in response to real-time marginal energy costs. Bates White observes that PHP contributions to fixed costs would be significantly higher under alternative NSPI industrial tariffs, acknowledging that that is precisely the intent of the LRT.

XIV.B.2.a. Additional Benefits to PHP from the LRT

In addition to the benefit of paying incremental cost plus a capped contribution to fixed costs, the LRT provides additional benefits to PHP, including the following:

- **Avoidance of DSM Costs:** The LRT explicitly states that the Demand Side Management Cost Recovery Charge is not applicable to PHP.
- **Avoidance of Renewable Energy Standard Compliance Costs:** It is Bates White's understanding that the LRT was intended to exclude any assignment of Renewable Energy Standard compliance costs to PHP.[427] As a functional matter, the fact that wind

[427] See discussion and findings in the Board Decision, 2012 NSUARB 126, M04862, pages 57–60.

generation is a must-take resource means that the differential methodology used to determine the incremental cost to serve PHP load would, as a matter of course, prevent wind costs from being assigned to PHP (the wind has to be taken by NSPI whether or not PHP is a load on the system, so none of the related cost can be considered an incremental result of PHP load). Moreover, must-take renewable generation provides an additional benefit to PHP because the generation is treated as bottom of the stack and tends to reduce the system marginal energy cost and the incremental cost of serving PHP load as determined by the differential cost method.

- **Information Access Allowing PHP to Manage Costs:** The LRT procedures require that NSPI provide PHP with hourly price forecasts for specific blocks of incremental load on a day-ahead basis and an additional seven-day forecast for peak and off-peak hours. NSPI must also provide PHP with information "to support PHP's operational decision-making and allow it to extrapolate potential prices in real time," including forecasted NSPI resource generation, scheduled imports, timing and duration of potential outages and return to service of offline resources. The degree of information that PHP has regarding NSPI operations is unique among NSPI customers.
- **Access to Imports:** As discussed above, the LRT provides PHP access to import opportunities as an alternative to service from NSPI resources.

XIV.B.3. The LRT and the Port Hawkesbury Biomass Plant

Through a separate services agreement (dated May 6, 2016) between PHP and NSPI, PHP is granted the option to request electricity from the Port Hawkesbury Biomass Plant for PHP's own use and at its own cost, when the plant is not dispatched by NSPI for system needs.

The Port Hawkesbury Biomass Plant, which entered service in 2013, has a 60 MW nameplate generating capacity (maximum net hourly output during the Audit Period was approximately 57 MW). The plant was developed via NSPI's purchase of the Port Hawkesbury paper mill's existing boiler and related assets and the addition of a steam generator. Initially, the Biomass Plant was required by provincial legislation to operate on a must-run basis. This requirement was put in place contemporaneously with the consideration by the Board of the co-application by NSPI and PHP in 2012 for approval of the LRT and proposed arrangements regarding the biomass facility, when it was determined that the facility would likely not operate to produce electricity on an economic basis in 2013 and 2014. The Board construed that, as a result of a legal requirement to operate the plant on a must-run basis, the costs of non-economic electric generation would not be considered incremental to PHP's load and would therefore not be assignable to PHP under the LRT.[428] To the extent that electric generation from the plant was not economic during the must-run period, those economic costs were borne by FAM customers.

[428] See discussion in Re Pacific West Commercial Corporation, 2012 NSUARB 126, paragraphs 172–179.

The must-run requirement for the biomass plant was removed as of the end of the plant's annual shutdown in April 2016, and since that time NSPI has committed and dispatched the plant for system needs on an economic basis. Under the terms of the May 2016 services agreement, NSPI provides PHP with a daily day-ahead forecast indicating whether it intends to operate the Biomass Plant the following day. If the forecast indicates that NSPI does not intend to operate the plant during the following day, PHP has the option to request that NSPI operate the plant using fuel owned by PHP, with PHP also being responsible for the incremental cost of electric energy necessary to run the turbine generator (i.e., parasitic or station load). For the purposes of the LRT, energy provided to PHP in this way is deemed to have a zero hourly incremental fuel cost. Effectively, the tolled generation from the Biomass Plant offsets PHP's load for the purposes of determining incremental cost under the LRT. More precisely, PHP's total load is considered under the LRT, with the portion served via the Biomass Plant tolling arrangement priced at zero incremental fuel cost.

This accounting treatment is significant because it means that PHP is assessed the fixed cost contribution rate of $2/MWh, and the variable costs specified under the LRT, on its total load, not on its load net of the tolled energy from the Biomass Plant. This is appropriate because PHP does not otherwise cover any fixed costs associated with the Biomass Plant. Put another way, it would *not* be appropriate to assess the fixed charge rate on load net of tolled energy, because PHP is not billed for any portion of the fixed costs of the plant. The accounting treatment also has implications for interpreting the LRT data reported by NSPI, because the PHP energy quantities in the monthly FAM and quarterly LRT reports reflect the full PHP load, while the reported incremental costs apply only to the portion of PHP load that is *not* served under the tolling arrangement. Figure XIV-4 repeats the LRT energy and total billed cost for the quarterly periods after removal of the must-run status of the Biomass Plant. The PHP energy shown in Figure XIV-4 is net of the energy supplied under the tolling arrangement. The net rather than gross energy quantity is also reflected in the calculated cost rates for energy and total billed amounts per MWh.

Figure XIV-4. LRT Data with PHP Energy Net of Tolled Biomass Energy

	2016		2017				Total
	Q3	Q4	Q1	Q2	Q3	Q4	
Energy excluding toll supply, MWh	[redacted]						
Energy Cost, $	[redacted]						
Total Billed, $	[redacted]						
Energy Cost, $/MWh	[redacted]						
Total Billed, $/MWh	[redacted]						

Bates White recommends that NSPI clarify its LRT reporting to distinguish between PHP energy served by NSPI at incremental cost and PHP energy provided at zero incremental cost to NSPI via the tolling arrangement. We also recommend that NSPI include in its FAM reporting generation data for the Biomass Plant that breaks out energy generated for FAM needs and energy generated at PHP's option. Figure XIV-5 summarizes the data for quarters following the removal of the Plant's must-run status.

Figure XIV-5. Port Hawkesbury Biomass Plant Generation for PHP and for NSPI (Post Must-Run Status)

	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	Total
Gen for PHP, MWh	[redacted]						
Gen for NSPI, MWh							
Totals							

The data demonstrate that the Biomass Plant is generally not economic for NSPI, yet it apparently has significant value to PHP when the effect on the incremental cost of PHP's remaining load is factored in. Bates White did not have access to data regarding PHP's actual cost of fuel when NSPI opted to run the Biomass Plant for its own needs, yet we find that the value to PHP of having the plant run is understandable even when the cost rate of incremental energy from NSPI is below that of the Biomass Plant. For example, if NSPI tells PHP that in a given hour the incremental cost to serve the paper mill would be $7,000 at 140 MW of load ($50/MWh) and $4,500 at 100 MW of load ($45/MWh), it would be economic for PHP (but not NSP) to run the Biomass Plant at 40 MW at a cost of $2,200 ($55/MWh). The comparison of total incremental cost to PHP when it decides to run the paper mill at 140 MW of load, with and without exercising its option on Biomass generation, is presented in Figure XIV-6.

Figure XIV-6. Illustrative Example of PHP Costs with Biomass Plant Option

	PHP Load, MW	Cost rate, $/MWh	Cost, $
Case 1 - No Biomass Generation			
Biomass	0	$55	$0
NSPI Service	140	$50	$7,000
Totals	**140**		**$7,000**
Case 2 - 60 MW Biomass Generation			
Biomass	40	$55	$2,200
NSPI Service	100	$45	$4,500
Totals	**140**		**$6,700**

In either case, NSPI would not find it economic to operate the Biomass Plant for system needs (if the plant were economic in the hour, PHP would not have the option to take energy from the facility). Incremental pricing to PHP for both Biomass and system energy ensure that FAM customers are not exposed to the short-term costs of serving PHP load. PHP has advantageous access to energy from the biomass facility that is comparable to its access to energy from the NSPI system—that is, PHP bears only a small portion of fixed costs. However, the benefit from the biomass facility is not exclusively PHP's. This is demonstrated by the generation data for Q4 2017 in Figure XIV-5 which shows that NSPI took [redacted] of Biomass generation in that quarter. System costs were [redacted] that quarter, making the Biomass Plant economic in [redacted] of hours). PHP took energy from the plant in [redacted] hours. While PHP has an advantageous option on Biomass Plant generation, NSPI's other customers have the primary option on taking power from the plant, just as they do with other system resources.

It is also important to note that the more-or-less continuous operation of the Biomass facility boilers to serve PHP steam needs increases the responsiveness of the generation plant when it is economic for either PHP or NSPI. NSPI indicated to Bates White that the generator could typically be brought online within about five minutes.

XIV.B.4. Considerations in Anticipating Potential Renewal of the PHP LRT

[redacted] We offer several observations regarding the LRT that are relevant to evaluations of potential extension and modification of the PHP LRT.

XIV.B.4.a. System Impacts

XIV.B.4.a.i. Operations

As described above, Bates White finds that the differential cost method is a reasonable means to determine the incremental cost impact of PHP load and that the particular procedure appropriately captures commitment impacts as well as marginal dispatch effects. At the same time, we find that there is insufficient clarity and specificity regarding the protocol that guides manual interventions applied by NSPI staff in the commitment process, and that there is insufficient documentation of such interventions when they occur. We recommend that NSPI establish and document a clear protocol for applying manual adjustments and establish reporting methods to provide greater transparency around this process. These procedures should be applied to both the advance differential cost forecasts provided to PHP and to the after-the-fact differential cost determination used to bill PHP.

XIV.B.4.a.ii. Fuel Adjustment Mechanism

The LRT requires that "[n]o FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue which can directly impact on NSPI's real time incremental electricity costs." It is Bates White's understanding that PHP is in fact a regular intervenor in FAM proceedings. While it is conceivable that PHP's intervention is justified by the latter condition in the requirement—that is, that NSPI is engaging on issues that can directly affect the incremental costs to which it is exposed—we find it unlikely that this would justify regular intervention. Moreover, it is concerning that PHP could have influence over matters that affect its exposure to costs that otherwise must be borne by FAM customers. Just one example of this is that PHP would generally benefit from NSPI operating procedures that cause more baseload resources to be committed to serve load. We recommend that the Board, NSPI, and PHP work to establish clear criteria for when participation by PHP in FAM proceedings is consistent with the language of the LRT requirement.

XIV.B.4.a.iii. Planning

One of seven conditions from the PHP Energy Supply Protocol under the NSPI tariff is that "NSPI will not include PHP in its planning considerations, including future capacity additions or the restart of generation which has been seasonally shut down." NSPI should affirm to the Board that it meets this condition in practice and in principle and that its planning procedures and assumptions are not affected implicitly by the existence of PHP load. The kind of implicit effect of concern can be illustrated by a hypothetical situation in which, because PHP load has been notably consistent across recent years (see Figure XIV-1, it becomes "understood" that certain NSPI resources must be committed on a consistent basis, and this understanding is then implicitly incorporated in the many assumptions, interpretations and judgements that are made in the planning process. Bates White has seen no evidence that PHP load affects NSPI planning explicitly or implicitly. At the same time, PHP represents a significant proportion of NSPI's system load, and there is ample documentation that managing the need to meet PHP load is a central part of the daily operations process, and that the engagement between PHP and NSPI is substantial and frequent. Bates White has no specific recommendation as to how NSPI could better provide the Board confidence that PHP is not a factor, even implicitly, in NSPI's planning process, except to encourage NSPI to show that it embraces this condition fully in its planning procedures.

XIV.B.4.a.iv. Contribution to Fixed Costs

As noted above, the minimum fixed cost contribution of $2.00/MWh and the cap on additional fixed cost contribution based on net earnings at a combined total of $4.00/MWh have recently been affirmed by the Board for the remainder of the LRT term. Whether additional fixed cost contributions are warranted is determined based on the audited financial results of PHP, and additional contribution has been made only once, for 2015. Understanding that this approach was the result of an extended process of negotiation, stakeholder input, and review by the Board, we observe that, looking forward to a potential renewal or extension of the LRT following the end of the current term in December 2019, there are alternative mechanisms that could be considered. One would be to set a reference value for the incremental energy rate plus variable cost adders—say, $55/MWh. PHP would be billed its actual incremental cost according to the existing LRT methodology. The fixed-cost contribution would not be a preset adder but would be the difference between the incremental cost (including variable cost adders) and the $55/MWh reference level, whenever the reference level was greater. Such an approach would have several benefits: (1) it would reward increased cost efficiency on PHP's part, as marginal net earnings would not automatically go to additional fixed-cost payments; (2) it would reduce the administrative complexity and delay in determining additional fixed-cost contributions under the current LRT; and (3) it would create an automatic adjustment mechanism in which PHP's fixed-cost contribution would rise when PHP could afford greater payments and fall, potentially to zero, when PHP's costs rise.

XIV.B.4.a.v. Biomass Plant

Considering that NSPI dispatched the Biomass Plant economically in [redacted] hours during the Audit Period and that PHP covered only incremental costs (and not fixed costs) of the plant when it exercised the option to run it, it is important to consider whether the Biomass Plant has economic value to FAM customers in the absence of PHP load. If the going-forward cost of the Biomass Plant exceeds the expected value of energy and capacity to FAM customers, then FAM customers should not bear the going-forward costs of the plant in full. The best way to evaluate the plant's value to the NSPI system is as part of a complete IRP study, which Bates White recommends in the Power Plant Performance Chapter, adhering to the tariff requirement that PHP load be excluded from consideration in the process.

Given the significance of the Biomass Plant in the context of the potential renewal or extension of the PHP LRT, we recommend that NSPI perform a separate analysis (i.e., separate from an IRP) to determine the value of the Biomass Plant to FAM customers in the absence of PHP load. Such a study would establish whether, looking forward, any of the costs of the facility are appropriately considered incremental to PHP load, and would inform considerations of how to shield FAM customers from such costs.

XIV.C. Conclusions

Conclusion XIV-1: The differential cost methodology used to determine charges to PHP reasonably captures the short-term incremental cost of PHP load and was generally implemented appropriately during the Audit Period.

Conclusion XIV-2: As a result of billing errors during the Audit Period, [redacted] NSPI implemented a billing correction, and PHP has paid the amount, which is reflected in the May FAM report as an adjustment on the 21-May-2018 to 27-May-2018 bill. NSPI has introduced new control procedures intended to prevent the errors that caused the erroneous assignment of import costs.

Conclusion XIV-3: As with the general resource dispatch process followed by NSPI, the differential cost methodology reflects discretionary interventions by NSPI staff that are not clearly anchored in company protocols, and are not well documented.

Conclusion XIV-4: The treatment of PHP-requested imports under the LRT protects FAM customers from bearing any incremental costs from PHP's access to imported energy.

Conclusion XIV-5: NSPI's LRT reporting does not distinguish between PHP energy served by NSPI at incremental cost and PHP energy provided at zero incremental cost to NSPI via the tolling arrangement. Similarly, NSPI's FAM reporting of generation data for the Biomass Plant does not distinguish between energy generated for FAM needs and energy generated at PHP's option. (See recommendations, below.)

Conclusion XIV-6: The Biomass Plant was generally not economic for NSPI during the Audit Period, yet had significant value to PHP, based on the fact that more than 75% of plant generation during the Audit Period was pursuant to PHP's option to run the plant when not dispatched by NSPI.

XIV.D. Recommendations

Recommendation XIV-1: NSPI should clarify its LRT reporting to distinguish between PHP energy served by NSPI at incremental cost and PHP energy provided at zero incremental cost to NSPI via the Biomass Plant tolling arrangement.

Recommendation XIV-2: In its FAM reporting of generation data, NSPI should provide data for the Biomass Plant that breaks out energy generated for FAM needs and energy generated at PHP's option.

Recommendation XIV-3: As recommended separately in the Economic Commitment and Dispatch Chapter, we recommend that NSPI establish and document a clear protocol for applying manual adjustments in its dispatch procedures and establish reporting methods to provide greater transparency around this process. These procedures should be applied to both the advance differential cost forecasts provided to PHP and to the after-the-fact differential cost determination used to bill PHP.

Recommendation XIV-4: The Board, NSPI and PHP should work to establish clear criteria for when participation by PHP in FAM proceedings is consistent with the language of the applicable LRT requirement.

Recommendation XIV-5: NSPI should perform a standalone analysis to determine the value of the Biomass Plant to FAM customers, looking forward, in the absence of PHP load. Such a study would establish whether any of the costs of the facility are appropriately considered incremental to PHP load and would inform considerations of how to shield FAM customers from such costs.

Board Issue 2: Tufts Cove Refurbishment Costs

XIV.E. Background

On June 30, 2017, NSPI made a capital application—CI #47331 – LM6000 191-253 Engine Refurbishment ("CI 47331")—with the Board for the approval and capitalization of costs in the amount of $1,023,342 for the refurbishment of its LM6000 191-253 combustion turbine operating at the time as Tufts Cove Unit 4.[429] On October 11, 2017, the Board denied NSPI's application.[430] The Board noted that the costs associated with CI 47331 were for "work related to an internal oil system manifold failure in April 2015, on LM6000 engine 191-253" that "rendered the engine unserviceable and posed a potential fire hazard… therefore requiring repair and maintenance."[431]

In reviewing the record, the Board identified two primary questions: "Should these expenditures be considered capital" and "Should these expenditures be charged to ratepayers?"[432] On the former point, the Board noted that NSPI's justification for its request to capitalize the costs was that it was in compliance with Accounting Policy 6000—Capitalization of Cost.[433] The Board noted that "[b]ased on the information filed…the work associated with this application is <u>not</u> capital in nature."[434] On the latter point, the Board stated:

> The performance issued identified, and presumably agreed to with the Original Equipment Manufacturer (OEM), call into question assignment of such costs to ratepayers. The Board understands the OEM and NSPI have reached an agreement on future services related, at least in part, to agreement on the failure mechanism that caused the oil manifold failure. Although the compensation was not assigned to this work order, it is related.
>
> Although NSPI has reached a settlement with the OEM, the Board does not currently have sufficient evidence to conclude NSPI has pursued sufficient compensation related to the overall engine performance issues. The Board also does not have sufficient evidence to conclude the agreed upon investment in two hot sections and combustors are justified at this time. Based on the information filed, the Board would like to ensure NSPI sought adequate compensation related to the issues and responsibility for maintenance of the assets.
>
> As such, the Board directs NSPI to isolate the costs of this expenditure, settlement, as well as costs of any other related engine refurbishment for further review. The most recent Fuel Audit

[429] NSPI, Capital Item Filed Outside the Quarter Package, June 30, 2017.

[430] Nova Scotia Utility and Review Board, M08144 – NSPI – CI # 47331 – LM6000 191-253 Engine Refurbishment U & U (P-516), October 11, 2017 (Board October 11 Order).

[431] Board October 11 Order, page 1.

[432] Board October 11 Order, pages 1 to 2.

[433] Board October 11 Order, page 1.

[434] Board October 11 Order, page 2.

> included recommendations related to performance concerns at the Tufts Cove combined cycle plant. The Board directs the fuel auditor to review these costs, as well as any related expenditures, and report back to the Board on whether they are appropriately assigned to ratepayers….The Board finds the justification provided by NSPI is insufficient to support approval of this work order, therefore does not approve this work order totaling $1,023,342.[435]

On November 6, 2017, NSPI requested that the Board reconsider its application CI #47331 for recovery approval and capitalization; on November 17, 2017, the Board issued an order denying NSPI's request, stating that:

> [T]he additional information submitted by [NSPI] on November 6, 2017 does not provide sufficient support for the Board to alter this decision. Furthermore, the decision on whether this expenditure qualifies as capital does not impact the Board's Decision to not approve the work order. In its Decision letter, the Board directed an in-depth review of the related expenditures through the FAM Audit. While the Board does not approve this expenditure at this time, the cost will remain in the FAM until the FAM Audit Decision is issued.[436]

In addition to the Tufts Cove cost issues identified above, the Board also noted that in its review of this issue in M08144, it was also discovered that

> NSPI has capitalized $514,751 related to a 2013 CT Asset Optimization Study. It is not clear how these costs meet the criteria for capitalization. As these costs were distributed across 20 separate capital work orders, the Board directs NSPI to file a submission no later than November 1, 2017, that explains how associated costs from as far back as 2013 were accounted for. For each capital project, the submission is also to identify how the cost was justified and highlight how this element was presented for Board approval.[437]

Below, we address both issues identified in the Board's October 11, 2017 Order.

XIV.F. Findings

XIV.F.1. Recovery, Capitalization of Engine 191-253 Refurbishment Costs

Engine 191-253 experienced an internal oil system manifold failure on April 2015 that rendered it unserviceable and that posed a potential fire hazard. This engine was thus removed from service and shipped to an OEM-approved maintenance facility for assessment. To promptly restore Tufts Cove Unit 4

[435] Board October 11 Order, page 2.

[436] Nova Scotia Utility and Review Board, M08144 – NSPI – CI # 47331 – LM6000 191-253 Engine Refurbishment U & U (P-517) – Request for Reconsideration, November 17, 2017 (Board November 17 Order).

[437] Board October 11 Order, page 2.

into service, the engine was replaced with rotable LM6000 Engine 191-332, which had been repaired for a similar oil leak in the compressor rear frame (CRF).[438]

The CRF oil leaks in both LM6000 turbines were assessed and repaired at TransCanada Turbines, as the OEM's (General Electric) warranties on the units had expired at the time of the CRF oil leak, and NSPI had unresolved issues with the quality of prior maintenance services work performed at the OEM's facilities. As with Engine 191-332, which experienced a similar failure, Engine 191-253 was refurbished by TransCanada Turbines at a total cost of $1,023,342.

In denying the approval of NSPI CI #47331 work order and capitalization approval, the Board questioned whether

a) the expenditures should be considered capital
b) the expenditures should be charged to ratepayers given the relatively short time (December 2012 to April 2015) that engine 191-253 had been in operation when the oil leak occurred.

Although NSPI had asked to capitalize the expenditure and not recover it through the FAM, the Board, by questioning the appropriateness of its capitalization, directed these costs to the FAM for the appropriate audit scrutiny by the Fuel Auditor.

In its November 6, 2017 response to the Board's decision letter M08144, NSPI included a copy of an independent auditor's opinion stating that the expenditures associated with the refurbishment of NSPI's 191-253 LM6000 engine were accounted in compliance with NSPI's accounting policies and US GAAP. We reviewed this opinion; we also reviewed NSPI's Accounting Policy and Procedures Manual Section 6000 – Assets Capitalization Cost, which states that "[a]n expenditure must create a benefit having a life of more than one year or adding more than one year to the originally estimated useful life of an existing asset to be considered a capital asset."[439] Here, we find that the expenditures for the oil manifold replacement have a useful life of greater than one year, and thus qualify for classification as a capital asset. We also note that the expenditures are not "annual fees or maintenance costs," which are meant to "maintain the existing asset" and thus would not qualify for capitalization under NSPI's accounting policies.[440] General 02 and 03, as these expenditures are not a recurring annual fees or maintenance costs, and they create a benefit having a life of more than one year; thus satisfying the criteria to be considered a capital cost.

As to the Board's questions of whether NSPI has obtained sufficient compensation from the OEM and whether NSPI has been prudent in its maintenance of the plant, Bates White finds the answers to both questions to be affirmative, as explained below.

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[438] NSPI has three rotable LM6000s at Tufts Cove: Engine 191-253; Engine 191-332; and Engine 191-443. These three engines can be rotated in and out of Tufts Cove units 4 and 5.

[439] NSPI's Accounting Policy and Procedures Manual Section 6000 – Assets Capitalization Cost, General 03.

[440] NSPI's Accounting Policy and Procedures Manual Section 6000 – Assets Capitalization Cost, General 02.

NSPI has indicated that in addition to the oil manifold failure, Engine 191-253 has had a history of unrelated performance and service issues for which NSPI has pursued compensation from the OEM. [redacted] NSPI claims that—along with its third-party experts—it has experience with the expected costs of most goods and services that are required on the LM6000 units and thus was confident that it would recognize an excessive "unreduced" market price.[441]

[redacted]

[redacted]

CRF oil leaks in LM6000 engines are not a rare occurrence. LM6000 oil manifold leaks got considerable attention at the 2017 Western Turbine Users Inc. (WTUI) Conference Breakout Session for LM6000 Owners/Operators. A review of OEM service bulletins attempting to prevent manifold failure related oil leaks, discussed in the conference, suggests that the leaks are an engine model specific issue and not the result of inadequate maintenance by NSPI.[442]

The reports of vibration-induced oil leaks in other LM6000 turbines in the WTUI Conference and NSPI's continuing collaboration with the OEM to mitigate oil manifold failure mechanisms suggest the potential for additional future oil leaks in NSPI's LM6000 engines. We note, however, that NSPI has complied with a GE service bulletin[443] related to the CRF oil manifold for all three of its LM6000s; the intent of the service bulletin upgrade is to improve the durability of the CRF manifold. To date, NSPI has

[441] NSPI noted that it gained this experience through prior capital projects and repairs on the LM6000 units, which required NSPI to purchase similar engine components.

[442] WTUI exists to provide members a forum for the exchange of technical, operations and maintenance information and experience to improve reliability and economic viability of GE LM series power facilities. See http://www.ccj-online.com/lm6000-breakout-at-western-turbine-invaluable-to-owneroperators/.

[443] General Electric Company, "SB LM6000-IND-307 CRF Oil Manifold Hardware Improvement," January 2015.

not reported any failures since the upgrades to the three LM6000s were made. Nevertheless, this is a performance area to monitor going forward.

XIV.F.2. 2013 CT Asset Optimization Study

In M08144 the Board identified that NSPI had capitalized $514,751 related to a 2013 CT Asset Optimization Study. The Board stated that it was "not clear how these costs meet the criteria for capitalization" and asked NSPI to "identify how the cost was justified."[444] That issue was resolved by the Board in its December 21, 2017, order, which accepted NSPI's allocation of costs for the study.[445] Nevertheless, the Board noted that the 2013 CT Asset Optimization Study may be valuable to the Fuel Auditor "in informing the extent of NSPI's maintenance and investments on the units at Tufts Cove."[446]

We reviewed the 2013 CT Asset Optimization Study,[447] which consists of individual assessments of the condition, operational and service history and the viability and cost of continued serviceability for the long term of each of NSPI's LM6000 engines (191-253, 191-332, and 191-443) and its CTs (Tusket Unit 1, Victoria Junction Units 1 and 2, and Burnside Units 1, 2, 3, and 4). We noted a series of key findings in the 2013 CT Asset Optimization Study:

- Regarding Tufts Cove 4 and Tufts Cove 5, TG Advisers, Inc. (TGA), the independent third-party consultant, found that the unit's "equipment requires regular inspection and maintenance to assure continued reliable service. NSPI's efforts in this areas are deemed to be sufficient." TGA also found that the unit auxiliaries were "fundamentally reliable and well maintained."
- Regarding NSPI's third LM6000 engine (191-253), TGA found that the unit "was procured pre-owned from General Electric Asset Management" and had been "inspected/overhauled/ refurbished at General Electric's Houston Service Center, with completion and performance acceptance in early August, 2012." TGA noted that "[i]n Summer of 2011, prior to NSPI's ownership, Engine 191-253 was overhauled and refurbished at General Electric's Houston Service Center… The engine showed evidence of normal wear and tear [and] required significant refurbishment, repair, and replacement of parts," but that "no evidence of significant failure was reported."
- TGA noted that units like these "require regular inspection and maintenance to assure continued reliable service" and that "NSPI's efforts in this area are deemed to be sufficient and good practice."

444 Board October 11 Order, page 2.

445 Nova Scotia Utility and Review Board, M08375 – NS Power – Capitalization of 2013 CT Asset Optimization Study, December 21, 2017 (Board December 21 Order), page 2.

446 Board December 21 Order, page 3.

447 Our review of the 2013 CT Asset Optimization Study, totaling over 4,700 pages, was not comprehensive; our analysis is not meant to capture every finding, conclusion, or recommendation from that study, but rather to provide our review of some of the more significant findings by the independent third-party consultant author of that study.

- TGA also reported, however, that "[i]n summary, engine 191-253 has failed to provide satisfactory service of any kind, since NSPI commissioning in late 2012… TGA has suggested a systematic approach to exploring life extension and reparability of major hot section components. This includes a program to identify alternative suppliers and contractors. The intended goal is to reduce sole-source reliance on the OEM, General Electric."
- TGA reports that Engine 191-332 does "require regular inspection and maintenance to assure continued reliable service" and that "NSPI's efforts in this area are deemed to be sufficient and good practice." TGA further notes that "[r]ecords indicate that engine 191-332 has been maintained in accordance with OEM recommendations, and good engineering practice," with sufficient documentation of inspection and maintenance activities.
- TGA reports that Engine 191-443 "has been maintained in accordance with OEM recommendations, and good engineering practice." TGA further notes that "[r]ecords indicate that Engine 191-443 has been maintained in accordance with OEM recommendations, and good engineering practice," with sufficient documentation of inspection and maintenance activities.
- TGA also noted "sufficient" inspection and maintenance at Tusket 1, Victoria Junction 1, Victoria Junction 2, Burnside Units 1, 2, 3, and 4.

The 2013 CT Asset Optimization Study enabled NSPI to understand the condition of their CTs and rank and prioritize the work associated with them based on their condition. We also find that the studies indicate that NSPI has maintained its LM6000s and CT assets reasonably, and we note the improved performance at Tufts Cove 4 and 5 during the Audit Period (as explained in the Power Plant Performance Chapter).

One shortcoming of the 2013 CT Asset Optimization Study, however, is that it does not fully inform the decision to invest in the preservation of these units vis-à-vis replacing them with more modern CTs or another type of fast ramping generation units. Notably, despite the reasonable maintenance history, some units have had operational issues—we highlight Engine 191-253, for example, which TGA reported in 2013 to have failed to provide satisfactory service of any kind, since NSPI commissioning in late 2012. We would argue, then, that NSPI should at least be aware—and make stakeholders and the Board aware—of the comparative cost of continuing to maintain these units, versus replacing them with more modern generation units. NSPI argues that the expense to retire the LM6000 engines—including remaining net book value—plus the cost of procuring new capacity is magnitudes higher than operating with the current assets. This may be true; our point, however, is that the 2013 CT Asset Optimization Study did not conduct such a comparison. Below, we include a recommendation that NSPI conduct such an analysis, subject to NSPI's IRP process identifying a need for peaking and/or fast-ramping capacity.

We note, too, that one of TGA's primary recommendations was for NSPI to reduce its reliance on General Electric, the OEM. Above, we explain that NSPI turned to an alternative supplier—TransCanada Turbines—for refurbishment of Engine 191-253 following its oil manifold failure. We find this to be both a reasonable decision (given TransCanada Turbines' status as a GE-certified maintenance contractor) and consistent with the recommendations of TGA.

XIV.G. **Conclusions**

Conclusion XIV-7: The refurbishment of Engine 191-253 in CI 47331 can properly be classified as capital since its benefits extend beyond one year, in compliance with Accounting Policy and Procedures Manual, Asset Capitalization of Cost, 6000.

Conclusion XIV-8: NSPI appears to have prudently maintained its LM6000 engines and CT assets according to OEM service bulletins and direction, as well as according to TGA in the 2013 CT Asset Optimization Study.

Conclusion XIV-9: The CRF oil manifold failure experienced in more than one of NSPI's LM6000 engines seem to be commonplace and happened outside the warranty period for the components involved, thus relieving the OEM from contractual responsibility.

Conclusion XIV-10: NSPI pursued and obtained reasonable compensation from the OEM for performance issues other than the CRF oil manifold failure.

Conclusion XIV-11: The 2013 CT Asset Optimization Study enabled NSPI to understand the condition of its CTs and rank and prioritize the work associated with them based on their condition. However, we believe the study does not fully inform the decision to invest in the preservation of these units vis-à-vis replacing them with more modern CTs or another type of fast ramping generation units. (Recommendation)

XIV.H. **Recommendations**

Recommendation XIV-6: In the Power Plant Performance chapter of this report, we have a recommendation to implement more regular and robust IRP planning. Subject to identifying the need for peaking and fast ramping resources in that study, NSPI should compare the economics of preserving the serviceability of its CT current fleet to the economics of replacing them with newer CTs or another type of fast ramping generation.

Board Issue 3: Internal Auditing

XIV.I. Background

The third issue the Board requested us to review was NSPI's internal auditing approach, which changed during the Audit Period.

XIV.J. Findings

Entering the Audit Period, NSPI's Fuel Manual (Revision 8) required an internal audit of the fuel procurement function every six years; the Fuel Manual stated:

> Internal audit shall conduct an audit of the fuel procurement function at least every six years. The scope shall include the fuel procurement function from solicitations and evaluations, through fuel receipt, to payment procedures. The audit shall determine adherence to and adequacy of the policies and procedures in the Fuel Manual.[448]

We note that this internal audit requirement is a comprehensive audit, requiring NSPI's internal audit to audit NSPI's fuel procurement function in its entirety, every six years. Revision 8 of the Fuel Manual had further internal auditing requirements:

> Internal audit shall conduct and identify the focus of periodic partial audits of the fuel procurement functions, in years which do not coincide with the conduct of external FAM audits. Upon completion, Internal Audit shall prepare a report of the findings to be submitted to the FST and the [NSPI] Audit Committee.[449]

On October 5, 2017, NSPI filed Revisions 9 and 10 to the Fuel Manual, which included revisions to the internal auditing provisions. The revised internal audit provision now states:

> Internal audit shall conduct a risk based component audit of FERM at least every two years, in a non FAM audit year. The scope shall be determined by Internal Audit and will be based on discussions with management, identifying areas of change, strategic initiatives, potential risks, etc. Internal audit will coordinate testing efforts with the NSPI NI 52-109 Compliance team to ensure there is no duplication of testing, where possible. Upon completion of component audits, Internal Audit shall prepare a report of the findings to be submitted to the FST. The Director, Fuels shall develop an action plan to

[448] NSPI Fuel Manual Revision 8, section 6.2.
[449] NSPI Fuel Manual Revision 8, section 6.2.

> address issues identified and will review with the VP Fuels and Energy. Internal Audit will monitor progress of these action plans.[450]

In other words, NSPI replaced its comprehensive, every-six-years internal audit of its fuel procurement function with a risk-based "component" audit held every two years (in non-FAM years). In response to this change, the Nova Scotia Consumer Advocate voiced concern, stating that "[NSPI] has the ultimate obligation to audit its fuel-procurement practices to ensure that such practices are prudent and reasonably conform to regulations and Board Directives" and thus "it is not appropriate to substitute an external audit conducted by the Board's consultant for a comprehensive internal audit."[451]

NSPI responded to the Consumer Advocate, noting that its intent is not to substitute internal audits with external audits, but that "outcomes from various activities, such as compliance activities, management findings, and internal and external audits, will be considered collectively in assessing risk and determining proper audit coverage."[452] NSPI further noted that it considers the "risk-based approach to be an appropriate and more efficient alternative to the previous internal audit requirement."[453] NSPI has also noted that "the Fuel Strategy Table endorsed a risk-based internal audit approach, consistent with recognized International Internal Auditing Standards."

The Board addressed the change in internal audit approach in its December 6, 2017, letter in M08331. The Board noted that though it is "cognizant of the fact that it does not approve the Fuel Manual," it must provide "rigorous oversight" of implementation of the FAM and that "[i]t does not appear to the Board that [NSPI] has ensured it had stakeholder agreement on changes prior to filing Revision #10 with the Board."[454] The Board also noted that the proposed change "shift[s] the internal audit process to a risk based approach, leaving judgement to the Internal Audit department… [and] appears to result in timelier audits, although based on what may be seen as a less prescriptive methodology."[455] In conclusion, the Board stated the following:

> It bears repeating NSPI has the ultimate responsibility for prudent performance related to fuel procurement and management. In this case, eliminating the requirement for any comprehensive internal audit may be appropriate, assuming there is sufficient evidence of a strong FAM governance record. The Board notes the 2016/2017 FAM Audit by Board Counsel Consultant, Bates White, is about to begin. As such, the Board expects the external auditor to review the first full cycle comprehensive Internal Audit and confirm NSPI's fuel procurement function lends itself entirely to a risk based approach.[456]

[450] NSPI Fuel Manual Revision 10, section 6.2.
[451] Board Internal Audit Letter, page 1.
[452] Board Internal Audit Letter, page 1.
[453] Board Internal Audit Letter, page 1.
[454] Board Internal Audit Letter, page 2.
[455] Board Internal Audit Letter, page 1.
[456] Board Internal Audit Letter, page 2.

During the Audit Period, NSPI's internal audit did not complete a comprehensive internal audit of NSPI's fuel procurement function. Instead, NSPI's Internal Audit conducted four internal "component" engagements: (1) a March 2016 audit of NSPI's efforts to calculate a shadow price for emissions that could be added to the cost of coal for dispatch purposes; (2) an August 2017 "NSPI Fuel Hedging: Financial Trade Execution Audit;" (3) a September 2017 review of costs charges under the Brooklyn PPA; and (4) on behalf of, and with assistance from NSPI's Internal Audit, Deloitte performed an internal compliance audit of the NSPI Fuel Hedging Plan. (We address the specifics of these internal audit engagements elsewhere in this report.)

NSPI's change in the Fuel Manual related to its internal auditing approach is, as NSPI notes, still in compliance with "International Internal Auditing Standards." We note that the risk-based approach to internal auditing is an accepted approach, including in the electric utility industry. We also grant the Board's point that this revised approach could lead to timelier audits, though we note that the previous approach also included component audits every two years.[457] We also agree with NSPI that a risk-based approach can be more efficient and avoid redundant looks at various aspects of NSPI's fuel and power procurement functions, particularly those that are of low risk for concerns or errors.

Nevertheless, we mention a few points regarding a transition from a comprehensive audit approach to a risk-based approach. First, the likelihood of errors increases under a risk-based approach; only comprehensive audits will ensure that every aspect of NSPI's fuel procurement function is examined. Second, external audits and internal audits are fundamentally different in that they offer auditors different access to information and pursue different goals. While external audits can help inform component internal audits, they are not a substitute for internal auditing. Third, taking away internal audit's ability to audit every aspect of NSPI's fuel procurement function every six years can prevent internal audit from being fully effective; the identification of components for auditing will not always identify the key areas to audit.

Regarding our observations during the Audit Period, we note two key points. First, in reviewing Internal Audit's reports, we found them to be helpful, clear, and well-written, with useful guidance for NSPI management. Internal audit is serving a crucial role, and when focused on an issue, that team is highly capable. Second, in 2017, we observed just three internal audits, one of which was largely accomplished by external auditing firm Deloitte. Moreover, two of the three internal audits conducted in 2017 were driven by findings and recommendations from the previous fuel auditor. To have confidence in the risk-based approach, the Board and stakeholders will have to see evidence that NSPI's Internal Audit department is identifying and testing the higher risk areas of its fuel procurement function, which should manifest itself in more frequent internal audit reports that address the higher risk areas of NSPI's fuel procurement function.

We note that there are "middle ground" approaches to internal auditing that may be worth considering. Such approaches would require NSPI to evaluate fuel procurement function processes at

457 See Fuel Manual Revision 8, section 6.2.

three risk levels: low, medium, and high. NSPI could identify the key controls to test within the particular fuel procurement function process, and based on the risk level for the particular process, Internal Audit would identify which controls to test. Lower risk processes would be reviewed, but at a high level; higher risk processes would be reviewed at a detailed level. This type of approach would still encompass a regular comprehensive audit—with the nuanced approach providing for a more detailed review of higher risk processes—and would also include component audits on a more frequent basis, as was the case under Revision 8 of the Fuel Manual.

XIV.K. Conclusions

Conclusion XIV-12: NSPI's revised approach to internal auditing has resulted in useful internal audit reports, is consistent with industry standards, and could result in timelier, more efficient internal auditing practices. However, because of the loss of its mandate to conduct a regular comprehensive internal audit, this approach will limit NSPI's Internal Auditing department's ability to fully execute its role, which is fundamentally different than the role of an external auditor. NSPI conducted just three component audits during 2017 (one largely accomplished by an external firm), the first year of the risk-based approach, and two of those three audits were related to recommendations from the previous external fuel auditor. While we do not have the basis for recommending that NSPI revert to its previous internal auditing approach, as found in Revision 8 of the Fuel Manual, we do conclude that FAM customers may be better served by revising NSPI's internal auditing provisions to reintroduce a regular comprehensive internal audit, but one that is more focused on higher risk processes. (Recommendation)

XIV.L. Recommendations

Recommendation XIV-7: NSPI should consider revising its internal auditing provisions to re-introduce a regular comprehensive internal audit that is more focused on higher risk processes.

REVISIONS TO CONFIDENTIALITY IN FAM AUDIT REPORT

Page	Change to Confidentiality
39	Figure III-4 has been unredacted.
47	The following has been unredacted: "Stellarton Mines or the Donkin Mine" and "the vast majority".
50	The following has been unredacted: "in high amounts" and "as its primary fuel".
81-82, 88	The following has been unredacted: "WeighWiz," "Log Inventory and Management System" and "LIMS".
99	The redactions were revised as follows:: "..[redacted] due to a mine slope failure, from [redacted] due to heavy berth congestion and lack of vessel availability, and from [redacted] due to extreme weather.'"
111	The redactions were revised as follows: [redacted] is currently NSPI's contractor for sampling and testing the quality of the biomass fuel deliveries, while also being NSPI's [redacted] We see this as an inherent conflict of interest for this counterparty."
128	The following has been unredacted: "There were seven days where transactions with Emera were at noticeably higher prices, but a review of the daily records indicated that the highest prices were due to…"..
168	The totals in Figure IX-19 have been unredacted.
168	The redactions were revised as follows: "As is shown in Figure IX-20, the NSPI fleet averages about [redacted] in average annual OM&G costs; the PHP biomass plant [redacted] and NSPI's wind generation [redacted] were the most expensive units, while the combustion turbines [redacted] and the hydro units [redacted] were the least expensive."
169	The figure "$9.49/MWh" has been unredacted.

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177	The redactions were revised as follows: Conclusion IX-16: Tufts Cove 1 suffered from a substantial outage during 2016 (stretching into 2017) that greatly reduced its performance. NSPI identified the cause as [redacted], with whom NSPI is currently in negotiations regarding a settlement. Besides maintenance costs of about [redacted], the outages of Tufts Cove 1 [redacted] have had an estimated impact of [redacted] on FAM customers. (Recommendation)
179	The redactions were revised as follows: Recommendation IX-2: In negotiating a settlement with [redacted], NSPI should seek to (1) [redacted] and (2) [redacted]
183	The following has been unredacted: "…in practice NBP markets energy externally first. NSPI has stated that the cooperative dispatch agreement will not progress to a fully integrated optimization of the two systems." is not confidential.
194	The paragraph under X.B.4 has been unredacted with the exception of a confidential pricing amount.
198	"87.4%" and "0.1% to 0.3%" have been unredacted.
204	The figure "$135.00/MWh" has been unredacted.
205	The totals line of Figure XI-5 has been unredacted.
216	"16.5% higher" and "down 17.4%"have been unredacted.
217	The following has been unredacted: "We note that NSPI's newly-created affiliate—Nova Scotia Power Energy Marketing Inc.—has filed for approval at the US Federal Energy Regulatory Commission for market-based rate authority as of April 20, 2018, which if approved, would allow NSPI to conduct power purchases and sales through its affiliate in the United States. Figure XI 12 shows all import transactions during the Audit Period, as broken down by counterparty."
218	The following has been unredacted: "at the behest of PHP. Under the LRT, PHP can request NSPI to engage in import transactions on PHP's behalf."

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221	The following has been unredacted: "…LRT, NSPI enters into a significant number of import transactions on behalf of PHP".
222	The following has been unredacted: "…LRT, NSPI is to pass on 100% of these costs to PHP; FAM customers are to see no impact of these transactions."
222	The redactions have been revised as follows: "After discovering this billing error, NSPI reviewed all its import transactions and discovered that NSPI had erroneously billed FAM customers for [redacted] of PHP import transactions, representing a total of [redacted] NSPI also discovered that it had erroneously billed PHP for import transactions done on behalf of FAM customers; this erroneous billing was for [redacted] of import transactions totaling [redacted] The net cost effect of these erroneous billings was that NSPI overcharged FAM customers by [redacted] over the two-year Audit Period and undercharged PHP by that same amount. NSPI adequately explained how it would address this billing issue and also noted that it would address the issue in its month-end FAM report. Indeed, on June 8, 2018, PHP paid the [redacted] outstanding and NSPI credited FAM customers the same amount. NSPI also introduced a new control procedure that requires the Team Lead to check and sign off on all Allegro transactions against the import transaction database to ensure that the data are correct before being downloaded for PHP billing purposes."
224	The paragraph under Figure XI-15 has been unredacted.
231	Conclusions XI-7 and XI-8 have been unredacted.
232	The following in Conclusion XI-16 has been unredacted: "for Port Hawkesbury Paper."

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232	The redactions have been revised as follows: NSPI also conducts import transactions on behalf of PHP under the terms of the LRT. During the Audit Period, NSPI erroneously billed some PHP import transactions to FAM customers and also erroneously billed some FAM customer import transactions to PHP. The total cost impact of these errors was a [redacted] overcharge of FAM customers and a [redacted] undercharge of PHP. NSPI has resolved this billing error by billing and receiving payment from PHP and crediting FAM customers for the [redacted]
234	The words "for PHP" in Recommendations XI-5, 6, and 7 have been unredacted.
265	The words "Director of Fuels" has been unredacted.