Nova Scotia Power Inc.
Annual FAM Reporting
Year 2025

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2025 Annual FAM Report
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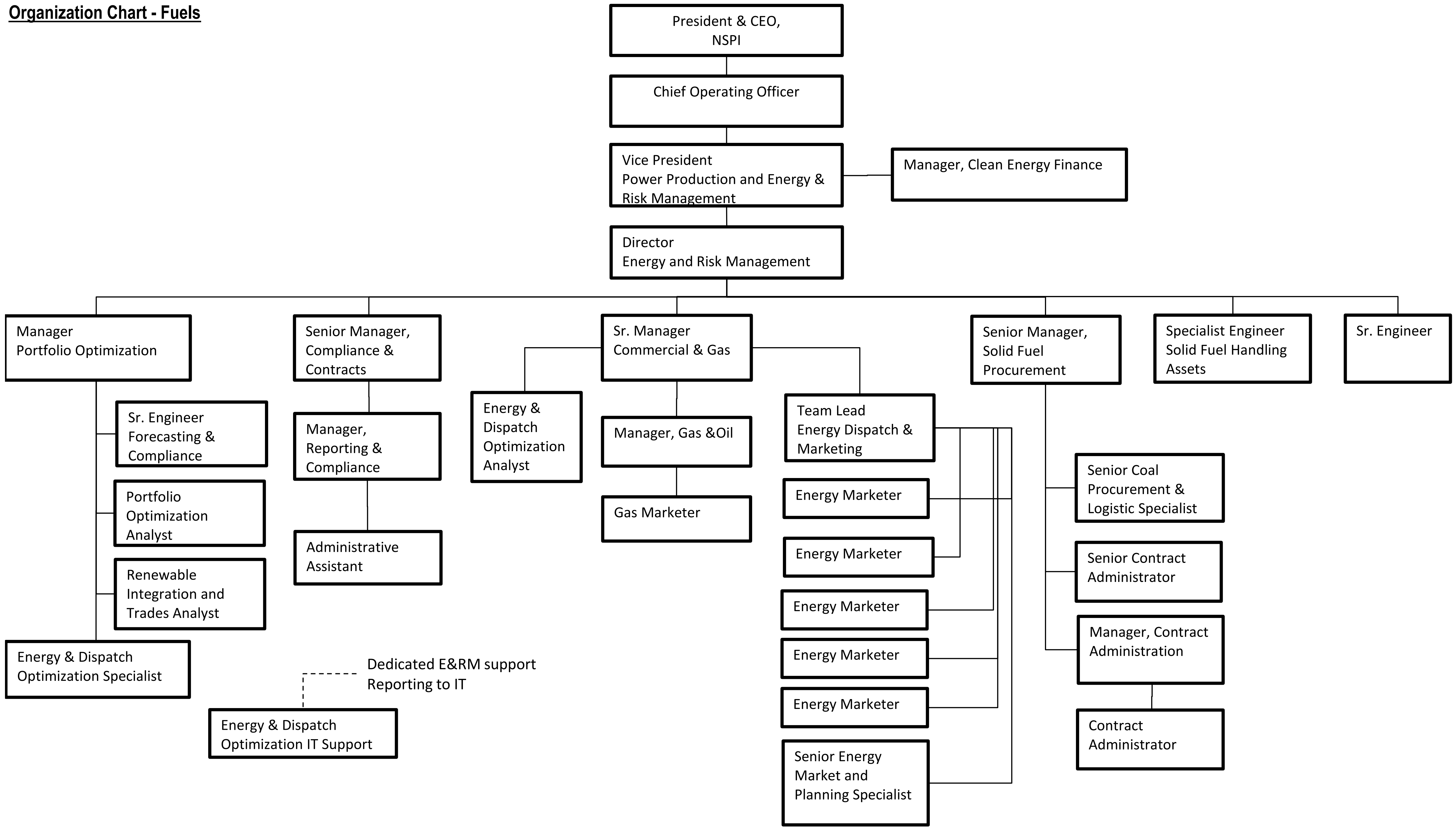
Organization Chart - Fuels



Organization Chart Commentary

The position of Senior Director, Energy and Risk Management was changed to Vice President, Power Production and Energy & Risk Management, effective on February 19, 2025.

The position of Natural Gas Scheduler & Analyst was created and filled on March 3, 2025.

The Senior Manager, Fuels Planning and Performance role assumed a new role within the company which was then filled by the Manager, Fuels Accounting & Performance effective July 18, 2025. The vacant Manager, Fuels Accounting & Reporting role was filled internally effective July 18, 2025.

The term Administrative Assistant left E&RM, effective October 10, 2025.

The Energy Market and Planning Specialist was promoted to Senior Energy Market and Planning Specialist.

The Cost Analyst was promoted to Contract Administrator.

The Senior Contract Administrator was promoted to Manager, Contract Administration.

The Manager, Solid Fuel Procurement was promoted to Senior Manager, Solid Fuel Procurement.

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Generation Unit Summary

Plant	Nameplate Capacity (MW)	In Service Year	Fuel Type	2025 Annual Energy (GWh)*
Lingan Unit 1	153	1979	Coal / Petcoke	692.5
Lingan Unit 2	148	1980	Coal / Petcoke	252.1
Lingan Unit 3	153	1983	Coal / Petcoke	644.4
Lingan Unit 4	153	1984	Coal / Petcoke	606.8
Tufts Cv Unit 1	78	1965	Oil / Natural Gas	128.8
Tufts Cv Unit 2	93	1972	Oil / Natural Gas	335.9
Tufts Cv Unit 3	147	1976	Oil / Natural Gas	514.0
Tufts Cv Unit 4 (LM 6000)	49	2003	Natural Gas	257.5
Tufts Cv Unit 5 (LM 6000)	49	2005	Natural Gas	240.7
Tufts Cv Unit 6 (LM 6000)	46	2012	Natural Gas	154.8
Pt Tupper	150	1973	Coal / Petcoke	690.3
Pt Aconi	168	1994	Petcoke / Coal	670.9
Trenton Unit 5	150	1969	Coal / Petcoke	383.9
Trenton Unit 6	154	1991	Coal / Petcoke	743.3
Port Hawkesbury Biomass	43	2013	Biomass	184.3
Burnside 1	33	1976	Light Oil	5.2
Burnside 2	33	1976	Light Oil	4.0
Burnside 3	33	1976	Light Oil	3.8
Burnside 4	33	1976	Light Oil	2.7
Victoria Junction 1	33	1976	Light Oil	1.3
Victoria Junction 2	33	1975	Light Oil	1.2
Tusket 1	33	1971	Light Oil	2.0
Hydro System	374	Various		594.0
NSPI Wind	81	Various		258.8
Amherst Solar Garden	2	2022		2.3
Total	**2,421.2**			**7,375.8**

* Net generation

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Fuel Cost Summary - per MWh

Properties	**Actual 2025**	**Actual 2024**	**Budget 2026***
Fuel for Generation - Domestic Load ($M)			
Solid Fuel	$337.8	$330.3	$293.5
Natural Gas	$122.8	$148.2	$87.4
Biomass	$21.7	$17.1	$21.6
Bunker C	$52.1	$22.9	$7.8
Furnace	$5.5	$6.3	$4.0
Diesel	$9.3	$7.1	$0.8
Additives	$15.0	$13.6	$17.9
GHG Compliance	$23.0	$19.3	$5.7
Subtotal	$587.2	$564.7	$438.7
Purchased Power	$291.3	$268.1	$278.4
Maritime Link	$184.9	($324.9)	$200.5
Fuel for Resale Net Margin	$0.1	$0.2	$0.0
Exports	$0.3	$0.0	$0.0
Fuel and Purchased Power	$1,064.0	$508.2	$917.5
Water Royalties	$1.1	$1.1	$1.1
Total Fuel and Purchased Power	$1,065.0	$509.2	$918.6
Less: ELIADC Revenue	($64.7)	($69.8)	($67.7)
Less: Export Revenue	($0.5)	$0.0	$0.0
Less: GRLF Fuel Costs	($1.6)	($1.5)	($1.1)
Less: 1PT RTP	($0.8)	($1.4)	($1.2)
Less: Shore Power	($0.2)	($0.0)	($0.1)
Less: EBS	$0.0	$0.0	($7.4)
Plus / (Less): Foreign exchange - Fuel Other	$0.0	$0.0	$0.0
Net Fuel and Purchased Power	**$997.2**	**$436.5**	**$841.0**
Total System Requirements (GWh)	11,473.6	11,326.3	11,392.0
Less: Export Sales and Attributed Losses	(4.5)	-	(13.5)
Less: GRLF Requirements	(17.7)	(17.1)	(15.0)
Less: ELIADC	(690.8)	(765.6)	(810.5)
Less: Shore Power	(1.7)	(0.2)	(1.3)
Less: 1PT RTP	(12.2)	(11.0)	(13.1)
Less: EBS	-	-	(95.7)
Less: Losses[(1)]	(768.4)	(745.7)	(756.7)
Total	**9,978.2**	**9,786.7**	**9,686.1**
FAM Fuel Costs per MWh Generated (2)	**$92.79**	**$41.45**	**$80.54**

Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items.

*The FAM Budget reflects the GRA Filing for 2026 of $918.6 million.

[(1)] Includes losses for all customer classes, with the exception of Export Sales.

(2) 2024 FAM Fuel Cost per MWh normalized for the receipt of the FLG2 was $87.58/MWh.

Fuel Specifications Summary - HFO

HFO QUALITY SPECIFICATION

Property	Requirement	ASTM Test
Gravity, ^{0}API- Apr 1 to Dec 31 Gravity, ^{0}API- Jan 1 to Mar 31	min. 9.0 min. 9.5	D1298 D1298
Saybolt Viscosity, Furol @ 50 ^{0}C	min. 150 max. 300	D445, D2161
Flash Point, ^{0}C (^{0}F)	min. 66 (150)	D93
Sulphur, wt. %	max. 2.2 (or 1.0)	D4294
Water by Distillation, vol. %	max. 1.0	D95
Compatibility, spot	max. 1	D4740
Hydrogen Sulphide, vol. ppm *(The preceding seven Properties are referenced in Section 13.8 (a))*	200	D5705
Gross Heat of Combustion, MMBtu/Bbl	6.325	D240
Ash, wt. %	max. 0.10	D482
Sediment by Extraction, wt. %	max. 0.25	D473
Sediment by Hot Filtration, wt. %	max. 0.1	D4870
(1) Vanadium, wt. ppm	max. 300	D5863A/B (1)
Sodium, wt. ppm	max. 50	D5863B
Ashphaltenes, wt. %	max. 10	ASTM D6560-00
Pour Point, ^{0}C (^{0}F)	max. 21 (70)	D97

Notes: 1)Test method ASTM-D-5863(B) will be used at discharge port to determine if discharge should be delayed while test method 5863(A) is performed. Test method ASTM-D-5863(A) will be used for pricing calculations at discharge port, and will be binding in the event of a dispute.

Fuel Specifications Summary - Diesel

PRODUCT CHARACTERISTIC	SPECIFICATION		TEST
	MIN	MAX	METHOD
Appearance	Clear & Bright		Visual
Ash, % mass		0.010	ASTM D 482
Carbon Residue on 10% bottoms, % mass		0.2	ASTM D 4530/D524
Cetane Number	40.0		ASTM D 613/D6890/D7170
Cloud Point, °C	Table 1		ASTM D 2500
Copper Corrosion (3h @ 50°C)		No. 1	ASTM D 130
Density @ 15°C, kg/m		881	ASTM D 1298/D 4052
Distillation, °C • 90% Recovered		360.0	ASTM D 86
Electrical Conductivity, at point, time and temperature of delivery to customer, pS/m	25		ASTM D 2624
Flash Point, °C	40.0		ASTM D 93
Lubricity	Satisfactory		CAN/CGSB 3.517
Pour Point, °C	report		ASTM D 5949/D97
Sulphur, mg/kg		15	ASTM D5453
Total Acid Number, mg KOH/g		0.10	ASTM D 974/D664
[1] Viscosity, cSt @ 40°C	1.70	3.60	ASTM D 445
Water and Sediment, % vol		0.02	ASTM D 1796(mod)/ D2709

1. If the fuel is designed for an operability temperature of below –20°C, then the minimum viscosity shall be 1.30 cSt@40°C. If the fuel is designed for an operability temperature between –20°C and –10°C, then the minimum viscosity shall be 1.50 cSt@40°C.

Fuel Specifications Summary - Mid Sulphur Coal

TECHNICAL SPECIFICATION - MID SULPHUR COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	12%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	12%	D3172
Sulphur	-	-	3%	D3177
Volatile Matter	35%	30%	-	D3175
Calorific Value (Btu/lb.)	-	12,800	-	D5865
Grindability (HGI)	50-60	50	65	D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury		Indicate typical level in bid		D6414 or 6722
Chlorine			1100 ppm	D4208-02

Fuel Specifications Summary - Low Sulphur Coal

TECHNICAL SPECIFICATION - LOW SULPHUR COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	15%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	9%	D3172
Sulphur	0.65%	-	1.1%	D4239
Volatile Matter	34%	30%	-	D3175
Calorific Value (Btu/lb.)	-	10,800	13,400	D5865
Grindability (HGI)	45-55	42	65	D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury		Indicate typical level in bid		D6414 or D6722
Chlorine			1100 ppm	D4208-02

Penalties/Premiums may be negotiated for Calorific Value, Sulphur, and Moisture with successful bidders.

Fuel Specifications Summary - Petroleum Coke

TECHNICAL SPECIFICATION - PETROLEUM COKE

Type: Delayed Petroleum Coke, Shot Coke only.

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	9%	D3302
Ash	0.5%	0.2%	1.0%	D3172
Sulphur	4-6%	-	6%	D4239
Volatile Matter	10%	8%	-	D3175
Calorific Value (Btu/lb.)	14,000	13,900	-	D5865
Grindability (HGI)	45-50	40		D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	12%	D4749
Vanadium, ppm	800		1900	D5056
Nickel, ppm	100		750	D5056
Mercury	Indicate typical level in bid			D6414 or D6722
Chlorine			1100 ppm	D4208-02

Fuel Specifications Summary - Natural Gas

Total Heating Value

(a) No natural gas received or delivered hereunder shall have a Total Heating Value below 36 MJ/m^3 or above 41 MJ/m^3.

(b) The Total Heating Value shall be determined by gas chromatographic analysis using most recent AGA standards or any revision thereof, or by other methods mutually agreed upon by Customer and Pipeline.

Composition

(a) Merchantability. The gas shall be commercially free, under continuous gas flow conditions, from objectionable odors (except those required by applicable regulations), solid matter, dust, gums, and gum-forming constituents which might interfere with its merchantability or cause injury to or interference with proper operations of the pipelines, compressor stations, meters, regulators or other appliances through which it flows.

(a) Oxygen. The gas shall not have an uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume, and both parties shall make every reasonable effort to keep the gas free from oxygen.

(b) Non-Hydrocarbon Gases. The gas shall not contain more than four percent (4%) by volume, of a combined total of non-hydrocarbon gases (including carbon dioxide and nitrogen); it being understood, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

(c) Liquids. The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

(d) Hydrogen Sulphide. The gas shall not contain more than six (6) milligrams of hydrogen sulphide per one (1) Cubic Metre.

(e) Total Sulphur. The gas shall not contain more than four-hundred and sixty (460) milligrams of total sulphur, excluding any mercaptan sulphur, per one (1) Cubic Metre.

(f) Temperature. The gas shall not have a temperature of more than forty-nine degrees (49^{o}) Celsius.

(g) Water Vapor. The gas shall not contain in excess of eighty (80) milligrams of water vapor per one (1) Cubic Metre.

(h) Liquefiable Hydrocarbons. The gas shall not contain liquid hydrocarbons or hydrocarbons liquefiable at temperatures warmer than minus nine degrees (-9^{o}) Celsius and normal pipeline operating pressures of between 690 and 9930 kPag.

(i) Microbiological Agents. The gas shall not contain any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems.

Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB). Tests for bacteria or bacterial agents shall be conducted on samples taken from the meter run or the appurtenant piping using American Petroleum Institute (API) test method API-RP38 or any other test method acceptable to Pipeline and Customer which is currently available or may become available at any time.

Fuel Specifications Summary - Biomass

Biomass Fuel shall be delivered as chips or hogged material comminuted to a nominal size target of thirty-five (35) to thirty-seven (37) millimeters or smaller, and ideally not contain pieces greater than one hundred fifty (150) millimeters in length.

All Biomass Fuel shall be substantially free of extraneous material including, but not limited to, rock, iron, steel, wire, construction debris, gravel, soil, metal, plastic and industrial waste.

All Biomass Fuel shall be comprised of natural, untreated and uncoated wood and wood waste, which, at no stage in its lifecycle, has been treated with organic and/or inorganic substances to change, protect or supplement the physical properties of the materials.

Biomass Fuel shall target the following average moisture content requirements (wet basis):

(i) **Secondary Forest Biomass:**

a) Nov to April: 30 day rolling average of 57% or less, maximum of 65%

b) May to Oct: 30 day rolling average of 52% or less, maximum of 60%

(ii) **Primary Forest Biomass**

a) Primary Sawmill chips:

1) Nov to April: 30 day rolling average of 55% or less, maximum of 65%

2) May to Oct: 30 day rolling average of 52% or less, maximum of 60%

b) Primary Fuel log chips:

1) Nov to April: 30 day rolling average of 45% or less, maximum of 55%

2) May to Oct: 30 day rolling average of 40% or less, maximum of 50%

c) Primary Forest Fuel chips:

1) Nov to April: 30 day rolling average of 48% or less, maximum of 55%

2) May to Oct: 30 day rolling average of 42% or less, maximum of 50%

Plant Performance

DAFOR	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1	0.0%	8.0%	8.0%	8.3%	5.8%	5.7%	5.2%
Lingan Unit 2	2.7%	0.0%	0.0%	0.0%	1.2%	6.8%	2.6%
Lingan Unit 3	6.2%	0.0%	0.2%	4.4%	3.2%	4.5%	0.1%
Lingan Unit 4	0.5%	5.1%	0.4%	2.4%	1.8%	2.4%	0.6%
Tufts Cv Unit 1	0.0%	100.0%	0.0%	0.0%	11.6%	8.3%	5.6%
Tufts Cv Unit 2	0.8%	0.0%	11.7%	0.5%	4.0%	8.3%	0.3%
Tufts Cv Unit 3	7.7%	0.3%	0.0%	18.8%	5.0%	6.9%	4.1%
Tufts Cv Unit 4 (LM 6000)	14.1%	8.6%	0.8%	0.1%	5.8%	4.1%	7.5%
Tufts Cv Unit 5 (LM 6000)	24.9%	1.7%	1.3%	0.3%	7.6%	3.0%	2.2%
Tufts Cv Unit 6 (LM6000)	7.5%	0.0%	1.6%	0.5%	2.7%	5.7%	1.2%
Pt Tupper	0.0%	12.0%	1.8%	1.7%	2.9%	14.7%	11.9%
Pt Aconi	3.0%	0.4%	0.0%	0.3%	1.2%	6.8%	11.1%
Trenton Unit 5	19.8%	33.3%	0.0%	7.3%	14.4%	9.7%	14.0%
Trenton Unit 6	5.6%	0.0%	0.0%	3.5%	2.9%	4.2%	7.8%
PH Biomass	50.0%	0.2%	7.9%	0.2%	1.7%	3.4%	6.7%

Definition: DAFOR = Equivalent Forced Outage time / (Equivalent Forced Outage Time + Total Equivalent Operating time)
*The Annual Budget is based on the 3 year trailing average (abnormal values from previous years are excluded)

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Plant Performance

Capacity Factor	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1	66%	41%	52%	48%	52%	31%	37%
Lingan Unit 2	33%	3%	0%	40%	19%	0%	12%
Lingan Unit 3	58%	15%	60%	59%	48%	32%	39%
Lingan Unit 4	43%	22%	59%	56%	45%	42%	28%
Tufts Cv Unit 1	44%	0%	19%	12%	19%	36%	60%
Tufts Cv Unit 2	49%	3%	41%	72%	41%	46%	49%
Tufts Cv Unit 3	52%	51%	29%	28%	40%	53%	62%
Tufts Cv Unit 4 (LM 6000)	66%	47%	66%	61%	60%	58% (1)	64%
Tufts Cv Unit 5 (LM 6000)	54%	33%	64%	73%	56%		67%
Tufts Cv Unit 6	40%	28%	40%	46%	38%		47%
Pt Tupper	65%	26%	52%	67%	53%	15%	43%
Pt Aconi	78%	53%	41%	11%	46%	72%	53%
Trenton Unit 5	51%	8%	1%	57%	29%	26%	21%
Trenton Unit 6	77%	39%	34%	71%	55%	59%	43%
PH Biomass	53%	48%	34%	61%	49%	48%	43%

Definition: Capacity factor = Actual Net GWh / (Net Operating Capacity X 8760 hrs)
*The Budget reflects the 2024 Q3F Internal Forecast of $1,039M.
(1) This value represents the combined capacity factor for Tufts Cv Unit 4, 5, and 6

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Plant Performance

Availability Factor	**Q1**	**Q2**	**Q3**	**Q4**	**Annual Actual**	**Annual Budget***	**Prior Year**
Plant							
Lingan Unit 1	100%	95%	55%	41%	73%	92%	73%
Lingan Unit 2	98%	100%	100%	77%	94%	88%	88%
Lingan Unit 3	87%	45%	100%	94%	82%	92%	87%
Lingan Unit 4	90%	37%	91%	100%	80%	92%	85%
Tufts Cv Unit 1	90%	78%	70%	88%	82%	67%	69%
Tufts Cv Unit 2	91%	91%	81%	0%	66%	91%	69%
Tufts Cv Unit 3	86%	62%	100%	84%	83%	91%	75%
Tufts Cv Unit 4 (LM 6000)	97%	72%	97%	92%	89%	91%	89%
Tufts Cv Unit 5 (LM 6000)	99%	71%	95%	98%	91%	92%	89%
Tufts Cv Unit 6 (LM 6000)	99%	63%	97%	92%	88%	91%	86%
Pt Tupper	94%	64%	84%	71%	78%	86%	73%
Pt Aconi	100%	89%	53%	65%	77%	82%	89%
Trenton Unit 5	91%	23%	100%	86%	75%	84%	93%
Trenton Unit 6	90%	99%	65%	87%	85%	88%	85%
PH Biomass	95%	81%	66%	86%	82%	92%	86%

Definition: Availability = (Operating hours + ABNO Outages) / 8760 hrs
*The Budget reflects the 2024 Q3F Internal Forecast of $1,039M.

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Plant Maintenance

OM&G Expense by Operating Group	Actual 2025	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Actual 2019	Budget 2025	Budget 2026
Lingan	$19.8	$18.5	$18.4	$17.1	$15.9	$15.2	$15.8	$18.9	$19.9
Tufts Cove	18.2	16.7	16.2	15.6	13.4	11.4	11.4	17.4	17.6
Pt. Tupper	9.5	8.4	7.9	7.8	7.5	6.8	7.9	8.6	8.9
Pt. Aconi	8.9	8.6	8.5	8.2	7.6	7.9	8.1	9.4	9.4
Trenton	14.7	13.5	12.7	12.4	11.3	11.4	14.3	13.6	14.1
Hydro	11.7	10.6	11.1	9.0	7.5	7.9	8.2	11.7	11.6
Wind	9.5	9.3	8.9	8.4	8.2	8.3	9.0	9.4	8.5
Combustion Turbine	2.0	2.2	2.1	2.0	1.7	1.4	1.7	2.6	2.7
Plant Operations	2.5	2.4	2.2	2.4	2.4	1.9	3.4	2.6	2.8
Biomass	6.1	6.5	6.6	6.2	6.3	6.2	6.5	6.9	7.1
Solar	0.1	0.1	0.1	-	-	-	-	0.1	0.1
Fuel, Energy & Risk Management	7.3	6.3	5.4	6.2	6.0	5.5	6.0	6.9	7.0
Total	$110.3	$103.1	$100.2	$95.4	$87.7	$83.9	$92.3	$108.1	$109.7

Capital Spending by Station	Actual 2025	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Actual 2019	ACE Budget 2025	ACE Budget 2026
Lingan	$6.4	$22.5	$23.1	$24.4	$15.6	$12.8	$16.1	$22.1	$28.8
Tufts Cove	15.5	23.4	26.7	23.6	12.8	7.0	12.1	25.7	34.2
Pt. Tupper	4.9	10.5	6.0	6.4	5.8	3.5	15.1	9.8	13.3
Pt. Aconi	21.0	19.8	11.5	15.3	12.2	12.4	14.8	19.1	12.7
Trenton	11.2	11.8	11.7	12.9	13.8	9.6	23.7	15.4	16.2
Hydro	53.3	40.2	49.1	88.8	76.5	29.9	34.3	68.5	42.5
Combustion Turbine (Includes LMs)	23.6	10.8	12.2	10.9	14.8	10.3	10.1	13.9	13.7
PH Biomass	6.6	5.5	4.9	5.8	2.5	2.0	1.1	5.0	5.7
Wind	1.6	1.8	2.8	5.6	3.1	1.1	-	4.5	6.1
Fuel, Energy & Risk Management	1.9	6.0	2.1	1.5	1.5	2.0	2.5	5.6	6.0
Total	$146.0	$152.2	$150.1	$195.2	$158.6	$90.6	$129.8	$189.5	$179.3

Major Projects - 2025

Project	Station
LM6000 191-332 Hot Sect Refurb 25	Combustion Turbine (Includes LMs)
CT VJ2 - Replace Generator Assembly	Combustion Turbine (Includes LMs)
CT VJ2 - Replace Generator Assembly	Combustion Turbine (Includes LMs)
CT - VJ2 - Control System Upgrade	Combustion Turbine (Includes LMs)
CT VJ2 Free Turbine Full Refurbishm	Combustion Turbine (Includes LMs)
RC Lingan Crossings Refurb	Fuel, Energy & Risk Management
ICP Rail Center Fuel System Refurb.	Fuel, Energy & Risk Management
RC TRMC Roof Structure U&U	Fuel, Energy & Risk Management
HYD WRC LEM Unit Rehabilitation	Hydro
HYD WRC Tailrace Rock Bolting Ph2	Hydro
HYD Ruth Falls Main Dam Refurb	Hydro
LEQ Canal, Gates and Tailrace	Hydro
Lower Great Brook Stoplog Refurbish	Hydro
Tusket Powerhouse Fish Passage	Hydro
HYD - Annapolis Decision Analysis	Hydro
HYD - Tidewater Facility Repairs	Hydro
HYD WRC Surge Lake Volume Optimizat	Hydro
HYD - COW 12 Overhaul	Hydro
WRC Tunnel T-1 Remediation	Hydro
HYD - Routine Equipment Replacement	Hydro
HYD COW 12 Generator Refurbishment	Hydro
HYD - Wreck Cove Controls Upgrade	Hydro
WRC Center of Main Access Tunnel Ro	Hydro
HYD GUL Generator Refurbishment	Hydro
HYD - Gulch Overhaul	Hydro
HYD - ANN Facility Isolation	Hydro
HYD - WRC Tailrace Rock Bolting	Hydro
HYD - Tusket Falls Main Dam	Hydro
HYD AVO 2 Rock Stabilization	Hydro
HYD AVO 2 Switchgear Replacement	Hydro
HYD - Avon 2 Controls Upgrade	Hydro
LIN Mill Refurbishment 2025	Lingan
LIN3 Boiler Refurbishment 2025	Lingan
LIN2 Boiler Refurbishment 2025	Lingan
LIN1 Boiler Refurbishment	Lingan
LIN4 Boiler Refurbishment 2025	Lingan
LIN2 SCC Refurbishment 2025	Lingan
LIN - Routine Equipment Replacement	Lingan
LIN4 SCC Refurbishment 2024	Lingan
PHB - Boiler Refurbishment 2025	PH Biomass
PHB - Precipitator Refurb 2025	PH Biomass
PHB - Air Heater Refurbishment 2025	PH Biomass
PHB - Conveyors & Handling Systems	PH Biomass
PHB-SD UU Stacker Conveyor Refurbis	PH Biomass
PHB - SD UU Precip Duct Work Refurb	PH Biomass

Major Projects - 2025

Project	Station
PHB- SD UU Wennberg South Screw Re.	PH Biomass
POA LP HIP Turbine Refurb.	Pt. Aconi
POA Boiler Refurbishment	Pt. Aconi
POA PE Cell 4 phase 3 development	Pt. Aconi
POA Boiler Refractory Refurb.	Pt. Aconi
POA Coal Gallery Refurbishment	Pt. Aconi
POA SH1 Refurbishment	Pt. Aconi
POA CW Pump Refurb.	Pt. Aconi
POA BFP Rebuild	Pt. Aconi
POA Coal Transformer Replacement	Pt. Aconi
POT - Turbine Valves Refurbishment	Pt. Tupper
POT - Boiler Refurbishment 2025	Pt. Tupper
POT - Routine Equipment Replacement	Pt. Tupper
POT - South Boiler Feed Pump Refurb.	Pt. Tupper
POT - Coal Mill Refurbishment 2024	Pt. Tupper
TRE5 - IP-LP Turbine Refurbishment	Trenton
TRE6 - Boiler Refurbishment	Trenton
TRE5 Baghouse Filter Replacement	Trenton
TRE5 - Burner Front Refurbishment	Trenton
TRE6 Mill Refurbishment	Trenton
TRE5 PE Secondary Air Heater	Trenton
TRE5 U&U Burner Nest Wtrwall Replacement	Trenton
TRE6 - Waterwall Replacement	Trenton
TRE6 UU Stack Breach Duct Refurb.	Trenton
TRE - Aux Lube Oil Pump Overhaul	Trenton
TUC1 HP Turbine Vibration Refurb.	Tufts Cove
TUC1 LPT Last Stage Blade Refurb.	Tufts Cove
TUC3 Turbine Valves Refurbishment	Tufts Cove
TUC2 - HP/IP Turbine Refurb. 2024	Tufts Cove
TUC Wharf Access Bridge Replacement	Tufts Cove
TUC1 AVR Replacement	Tufts Cove
TUC3 Boiler Refurb. 2025	Tufts Cove
TUC1 Boiler Refurbishment 2025	Tufts Cove
TUC2 Boiler Refurb. 2025	Tufts Cove
TUC1 LPT Last Stage Blade Refurb.	Tufts Cove
Wind - Routine Equipment Replacement	Wind

Major Projects - 2026 ACE

Project	Station
WRC LEM Balance of Plant	Hydro
LM6000 191-443 Engine Replacement	Combustion Turbine (Includes LMs)
TUC Shoreline Sheetpile Refurbishment	Tufts Cove
TUC2 Stack Coating and Structural Refurbishment	Tufts Cove
HYD - TUS 1 Overhaul	Hydro
HYD Deep Brook Spillway & Intake Refurbishment	Hydro
LIN1 HIP Turbine Refurbishment 2026	Lingan
TUC1 IP LP Last Stage Blade Replacement	Tufts Cove
POT - CW Pump & Motor Replacement	Pt. Tupper
HYD Ruth Falls Main Dam	Hydro
POA Ash Cell Capping/ Cell Development 2026	Pt. Aconi
CT - BGT2 Engine Refurbishment	Combustion Turbine (Includes LMs)
WRC LEM Unit Rehabilitation	Hydro
HYD - Gaspereau Dam Safety Remedial Works	Hydro
Tusket Falls Main Dam	Hydro
WIN - DIG Haights Brook Crossing Replacement	Wind
TUC6 Turbine Refurbishment	Tufts Cove
HYD - Hollow Bridge Stator Refurbishment	Hydro
Wind - Routine Equipment Replacement	Wind
HYD AVO 2 Access Road Stabilization	Hydro
HYD Upper Lake Falls 2 Overhaul	Hydro
HYD - Annapolis Decision Analysis	Hydro
WRC Surge Lake Volume Optimization	Hydro
POA Boiler Refurbishment 2026	Pt. Aconi
TUC3 Continuous Ash Hauling System	Tufts Cove
ICP - RC SCR Bridge 10.10 Refurbishment	Fuel, Energy & Risk Management
BGT2 Free Turbine Refurbishment	Combustion Turbine (Includes LMs)
HYD MacDonald Dam Access Improvements	Hydro
HYD ANN Sluice Gates and Check Refurbishment	Hydro
POA Boiler Refractory Replacement 2026	Pt. Aconi
TUC1 Lube Oil Cooler Replacement	Tufts Cove
CT BGT1 Generator Refurbishment	Combustion Turbine (Includes LMs)
LIN Mill Refurbishments 2026	Lingan
TRE5 - Boiler Refurbishment 2026	Trenton
TRE5 - Boiler South WW Panel at Lower Header.	Trenton
PHB - Boiler Refurbishment 2026	PH Biomass
TUC2 Stack 1 Platform Replacement	Tufts Cove
LIN BFP Cartridge Critical Spare	Lingan
POT - Boiler Refurbishment 2026	Pt. Tupper
LIN4 Boiler Refurbishment 2026	Lingan
LIN3 Boiler Refurbishment 2026	Lingan
LIN1 Boiler Refurbishment 2026	Lingan
PHB - Precipitator Refurbishment 2026	PH Biomass
TRE6 - Bottom Ash Refurbishment	Trenton
HYD Lumsden Rubber Dam Replacement	Hydro

Major Projects - 2026 ACE

Project	Station
POA Water Treatment Trailer	Pt. Aconi
LIN3 DCS Migration 2026	Lingan
TUS Air System Upgrade	Combustion Turbine (Includes LMs)
LIN 8th Stage Blade Replacement 2026	Lingan
WIN - DIG Gearbox Repl WTG19	Wind
WIN - DIG Gearbox Repl WTG10	Wind
LIN4 West Waterwall Refurbishment 2026	Lingan
Bear Head Ash Management Site - Life Extension	Pt. Tupper
HYD Dam Safety Routine	Hydro
POT - SOFA Duct Attachment Refurbishment 2026	Pt. Tupper
HYD ANN Facility Isolation	Hydro
POT - Polisher Caustic Skid Replacement 2026	Pt. Tupper
HYD - ULF2 Generator Refurbishment	Hydro
TRE6 6B Mill Bullgear and Pinnion	Trenton
Bear Head Erosion Management	Fuel, Energy & Risk Management
TUC6 HRSG Boiler Refurbishment	Tufts Cove
LIN3 A Hydrolox CW Screen Replacement 2026	Lingan
LIN3 B Hydrolox CW Screen Replacement 2026	Lingan
SCR Track Refurbishment Phase 1	Fuel, Energy & Risk Management
HYD Marshall Falls Dam Refurbishment	Hydro
ICP Storm Culvert Pipe Refurb U&U	Fuel, Energy & Risk Management
POT - Crane Motor & Controls Upgrade 2026	Pt. Tupper
HYD - WHR Fish Ladder Bypass Modifications	Hydro
POT - Seal Oil Cooler Replacement 2026	Pt. Tupper
LIN4 Aux Air Upgrades 2026	Lingan
LIN3 Turbine Valve Refurbishment 2026	Lingan
LIN1 Aux Air Upgrades 2026	Lingan
POA Coal Gallery Refurbishments	Pt. Aconi
HYD - Sloane Dam Refurbishment	Hydro
LIN DCS Migration	Lingan
TRE6 - Turbine Valves	Trenton
WIN NUT T14 T17 Bearing Replacements	Wind
TUC Roof Refurbishment	Tufts Cove
LIN BFP Refurbishment 2026	Lingan
HYD - Security Improvements (PSAD)	Hydro
TUC1 Governor Valve Replacement	Tufts Cove
POT - CW Pump House Power Cable Replacement	Pt. Tupper
POA CW Building Refurbishments	Pt. Aconi
ICP - RC TRMC Roof Structure Refurbishment	Fuel, Energy & Risk Management
TUC3 North Boiler Feed Pump Refurbishment	Tufts Cove
TUC2 Replace BAS	Tufts Cove
TUC3 Condenser Waterbox Refurbishment	Tufts Cove

System Losses

GWh	Actual 2025	Actual 2024	Budget 2025*	Budget 2026**
Total System Requirements	11,473.6	11,326.3	11,541.2	11,392.0
Domestic Electric Sales	10,705.1	10,580.6	10,764.8	10,621.8
Export Sales	4.5	0.0	2.5	13.5
Net System Losses	764.0	745.7	773.9	756.7
%	6.7%	6.6%	6.7%	6.6%

* 2025 Budget reflects the 2024 Q3 NSPI Internal Forecast for 2025 of $1,039.1M.
** 2026 Budget reflects the 2026 GRA Filing of $918.6M

Emission Compliance

Commentary

Nova Scotia Power (NS Power) is required to manage air emissions to annual fleet wide allocations, as per the NS Air Quality Regulations, the NS Greenhouse Gas (GHG) Emissions Regulations and the NS Output-Based Pricing System (OBPS) Reporting and Compliance Regulations.

As a result of NS Power exceeding the SO2 emissions allocations for 2021-2022 by 14,410 t, the Minister of Environment and Climate Change issued a Certificate of Variance (CoV) in January 2024, enabling NS Power to compensate for the excess emissions by the end of 2034. The CoV varied the annual SO2 allocations from 2025-2029 to provide relief. In 2024, NS Power made up 1,091 tonnes of the excess SO2, leaving 13,319 tonnes to be compensated for by 2034. The fleet emissions allocation of sulphur dioxide (SO2) emissions for 2025 is 45,000 tonnes. The unverified SO2 emissions for 2025 were 44,951 tonnes. The 2025 SO2 emissions will be finalized and third-party verified by March 31, 2026, as per Provincial reporting requirements.

The mercury diversion program that began in 2015, was executed under the Air Quality Regulations and ended in 2020. In 2025, NS Power had 94.56 kg of mercury credits banked. The 2025 annual mercury allocation is 35 kg and the maximum credits that may be used is 10kg, with the combined sum of emissions and credits capped at 45 kg. NS Power's Mercury Monitoring Protocol considers the accuracy of mercury emissions calculated using a mass balance to be +/-5% and if the annual total is within 5% of the annual compliance limit, then the lower number will be reported. The 5% recognition applies to the Lingan units, Trenton unit 6 and Point Tupper. This protocol is approved by NSECC. The unverified mercury emissions for 2025 are 46.9 kg and will be reported as 45kg. The annual emissions of 46.9kg is pending approval from NSECC regarding an update to the Mercury Monitoring Protocol for back-filling emissions from Trenton Unit 5. NS Power will apply 10 kg of mercury credits for a net mercury emissions in 2025 of 35 kg. The Hg emissions and application of credits for 2025 will be finalized and third-party verified by March 31, 2026, as per Provincial reporting requirements. NSPI continued the operation of seven (7) sorbent injection systems that were installed in 2009 to capture mercury in flue gas.

NS Power manages air emissions (SO2 and to some extent mercury) by purchasing and combusting specific quality fuels and procuring power from other sources (i.e., Imports and Independent Power Producers), and by increasing the amount of renewable generation.

The annual fleet allocation for nitrogen oxides (NOx) emissions for 2025 is 11,500 tonnes. The 2025 unverified NOx emissions were 11,470 tonnes. The NOx emissions for 2025 will be finalized and third-party verified by March 31, 2026, as per Provincial reporting requirements. NSPI continued the operation of the low NOx Combustion Firing Systems (LNCFS) on all Lingan units, Point Tupper and Trenton 6. These LNCFS represent the primary approach to reduce NOx emissions.

The GHG emission allocation for 2025 is 6 million tonnes CO2 eq. The 2025 GHG emissions are estimated at 5.65 million tonnes CO2 equivalent. The GHG emissions for 2025 will be finalized and third-party verified by March 31, 2026 as per Provincial reporting requirements.

In 2025, Nova Scotia implemented the Output Based Pricing System (OBPS) for Industry, that was effective for the 2023 year. The OBPS uses a carbon price and performance standard set by the federal government. NS Power's facilities are required to pay for emissions that are emitted above the annual emissions performance standard limit. All performance credits generated in 2024 were applied to the 2024 compliance obligation, resulting in a total OBPS cost of $32.37M for the calendar year. The compliance obligation for 2025 is $27.9M, pending third party verification. The dollar value of performance credits generated in 2025 is approximately $19.7M, pending third party verification. The net OBPS cost for 2025 will be $8.2M. NS Power's GHG emissions, costs and credits for the 2025 year will be third party verified and submitted to the Minister on December 31, 2026.

In addition to these fleet-wide caps, each generating facility operates within an Industrial Operating Approval which requires ground level ambient air quality to be maintained, plume visibility to be within limits and, in some cases, specific emission standards to be met. This is accomplished by maintaining the plant equipment in good working order and operating the plant within the specified limits.

Mercury Abatement Program
Impact on Fuel Use

Commentary including quantitative and qualitative descriptions of the impact on fuel use by virtue of the mercury abatement program

PAC 2025

The 2025 cap on annual emissions of mercury was 35 kg. However, NS Power was permitted to emit up to 45 kg by offsetting all emissions over 35 kg with banked mercury credits accumulated during the Mercury Diversion Program. To meet the mercury limits, NS Power continued operation of seven (7) mercury abatement equipment systems. The mercury abatement equipment systems consist of a front-end additive (calcium chloride) for oxidizing mercury to make it more readily captured as well as sorbent injection on the back-end in the form of powdered activated carbon (PAC).

NS Power optimized injection of powdered activated carbon (PAC) in 2024 to comply with mercury emissions regulations, as well as to remediate the remaining mercury emissions exceedance in 2022 when unexpected delays of Muskrat Falls energy delivery led to over emission of mercury. NS Power has now completed the make up of mercury emissions exceedance from 2022, as per the Remediation Plan accepted by the Minister of Environment and Climate Change.

NS Power continues to operate an internal mercury abatement team that focuses on maintaining reliability of mercury abatement equipment and quality control of emissions monitoring. The PAC types presently in use are well suited for NS Power's solid fuel types and mercury abatement systems.

Testing:
The purpose of the testing was to determine the long-term operational performance of a new sulphur-tolerant PAC product that was developed by the current PAC supplier during the 2018 PAC testing program. This testing started in 2019 and completed in 2020. No testing was performed in 2025.

Technical Issues
No technical issues to report.

Calcium Chloride 2025
Calcium chloride systems are installed at each plant. The systems are run as required, based on fuel blend.

Nova Scotia Power Inc.
Annual FAM Reporting
Year 2025

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Mercury Abatement Program
Technical / Capital Changes

Option	Description	Anticipated Result
NA		