Nova Scotia Power Inc.

Annual FAM Reporting

Year 2018

NON CONFIDENTIAL

2018 Annual FAM Report
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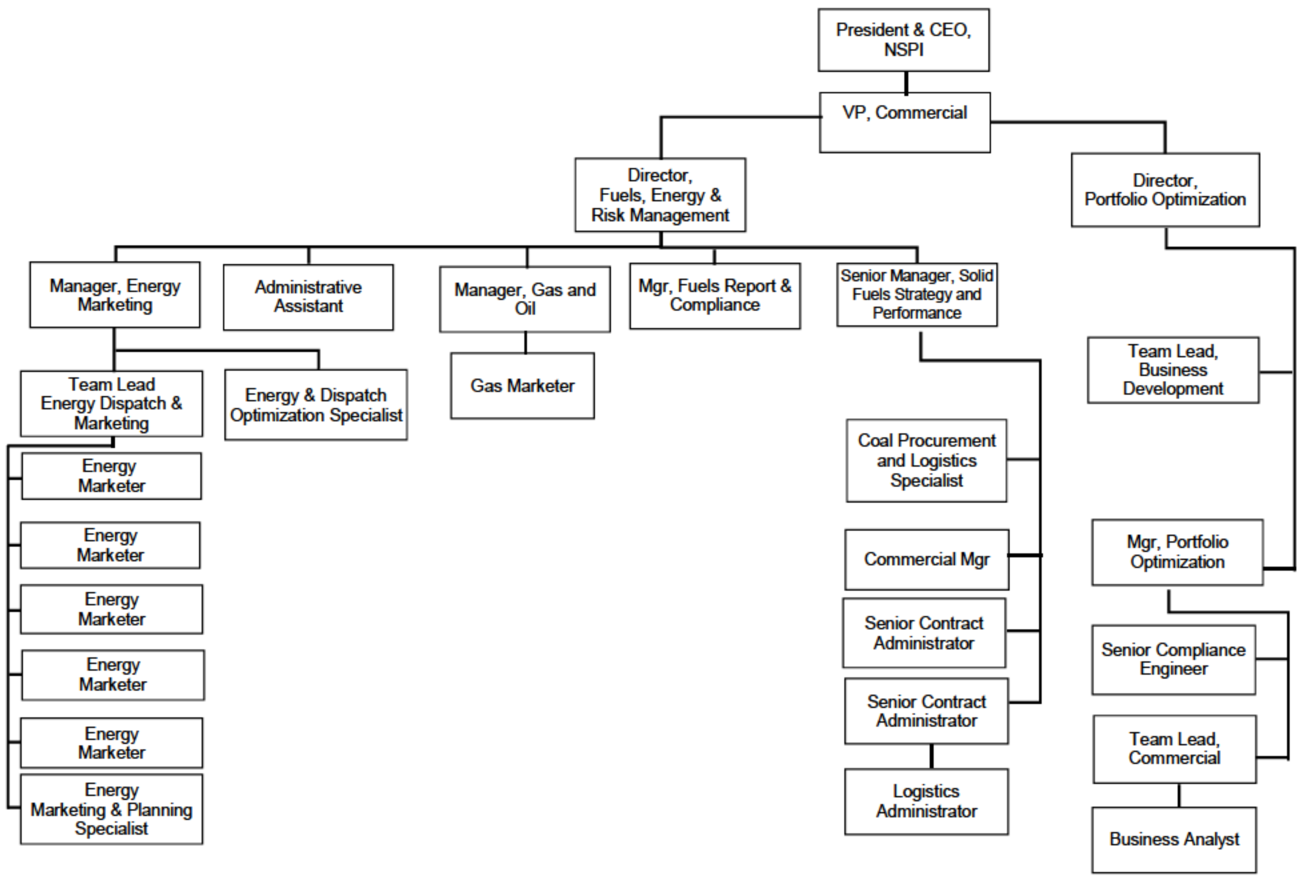
<u>Organization Chart - Fuels</u>



Organization Chart Commentary

Fuels hired a three month term employee to consult on Plexos modelling in January 2018.

An administrative assistant left the group in March 2018 and a replacement started in May 2018..

An IT Co Op student finished his work placement with the group and left in April 2018.

The Senior Compliance Engineer began reporting into the Manager of Portfolio Optimization, a change from previously reporting into the Senior Manager, Fuels, Strategy and Performance in October 2018.

The Business Analyst began reporting into the Team Lead Commercial, a change from previously reporting into the Manager of Portfolio Optimization in October 2018.

The Team Lead Commercial began reporting to the Manager of Portfolio Optimization a change from previously reporting to the Director of Portfolio Optimization in October 2018.

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Generation Unit Summary

Plant	Max Net Capacity	In Service Year	Fuel Type	2018 Annual Energy (GWh)*
Lingan Unit 1	153	1979	Coal / Petcoke	588.2
Lingan Unit 2	148	1980	Coal / Petcoke	426.0
Lingan Unit 3	153	1983	Coal / Petcoke	655.9
Lingan Unit 4	153	1984	Coal / Petcoke	748.2
Tufts Cv Unit 1	78	1965	Oil / Natural Gas	163.5
Tufts Cv Unit 2	93	1972	Oil / Natural Gas	233.4
Tufts Cv Unit 3	147	1976	Oil / Natural Gas	593.3
Tufts Cv Unit 4 (LM 6000)	49	2003	Natural Gas	214.7
Tufts Cv Unit 5 (LM 6000)	49	2005	Natural Gas	226.4
Tufts Cv Unit 6 (LM 6000)	46	2012	Natural Gas	108.3
Pt Tupper	150	1973	Coal / Petcoke	1,023.4
Pt Aconi	168	1994	Petcoke / Coal	1,056.0
Trenton Unit 5	150	1969	Coal / Petcoke	530.1
Trenton Unit 6	154	1991	Coal / Petcoke	1,020.9
Port Hawkesbury Biomass	43	2013	Biomass	188.8
Burnside 1	33	1976	Light Oil	3.9
Burnside 2	33	1976	Light Oil	4.1
Burnside 3	33	1976	Light Oil	4.5
Burnside 4	33	1976	Light Oil	0.9
Victoria Junction 1	33	1976	Light Oil	0.9
Victoria Junction 2	33	1975	Light Oil	0.4
Tusket 1	33	1971	Light Oil	(0.0)
Hydro System	399	Various		939.9
NSPI Wind	81	Various		262.5
Total	**2444**			**8,993.9**

* Net generation

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Fuel Cost Summary - per MWh

Properties	**Actual 2018**	**Actual 2017**	**Budget 2019***
Fuel for Generation - Domestic Load ($M)			
Solid Fuel	$206.4	$187.8	$152.9
Natural Gas	$80.5	$61.9	$19.6
Biomass	$8.4	$5.9	$2.7
Bunker C	$9.6	$4.9	$12.3
Furnace	$3.0	$2.2	$1.7
Diesel	$4.2	$1.7	$0.0
Additives	$14.9	$13.4	$13.0
Subtotal	$327.0	$277.7	$202.2
Purchased Power	$207.7	$191.7	$286.4
Maritime Link	$100.8	$0.0	$164.0
Fuel for Resale Net Margin	($0.2)	$0.2	$0.0
Exports	$6.0	$6.3	$0.0
Fuel and Purchased Power	$641.4	$475.9	$652.6
Water Royalties	$1.0	$1.1	$1.1
Total Fuel and Purchased Power	$642.4	$476.9	$653.7
Less: Load Retention	($68.6)	($46.6)	($39.2)
Less: Export Revenues	($7.3)	($5.6)	($2.5)
Less: GRLF Fuel Costs	($1.4)	($1.2)	($0.5)
Less: 1PT RTP	($0.6)	($0.4)	($0.3)
Less: Shore Power	($0.0)	($0.0)	($0.0)
Less: Back Up/Top Up	($1.4)	($1.0)	$0.0
Plus / (Less): Foreign exchange - Fuel Other	($0.0)	($0.0)	$0.0
Net Fuel and Purchased Power	**$563.0**	**$422.1**	**$611.1**
Total System Requirements (GWh)	11,361.9	10,976.6	11,331.1
Less: Export Sales and Attributed Losses	(91.6)	(103.4)	(50.0)
Less: GRLF Requirements	(20.4)	(25.7)	(23.9)
Less: Load Retention	(1,109.4)	(1,006.9)	(1,058.3)
Less: Shore Power	(0.8)	(1.0)	(1.0)
Less: 1PT RTP	(11.5)	(10.0)	(9.8)
Less: Back Up / Top Up	(25.1)	(20.5)	-
Less: Losses*	(742.3)	(729.0)	(725.6)
Total	**9,360.9**	**9,080.2**	**9,462.5**
FAM Fuel Costs per MWh Generated	**$55.72**	**$43.03**	**$59.98**

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 2019 BCF Refresh filing of $653.7M.
*Includes losses for all customer classes, with the exception of Export Sales.

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

Nova Scotia Power	Combustion Turbine	Delivered Dec-Feb 28th
Product Specifications		
Property	MIN/MAX	ASTM Test Method
Appearance	Clear and Bright	Visual
Density,Kg/M3	0.850	D1298
Distillation 90% Recovered	290.0 MAX	D86
Cloud Point	CP -34 MAX Temp	D2500
Pour Point(Deg C)	Report	D97
Viscosity	1.1 min-1.8 Max	D445
Octane Number	40 MIN	D613
Sulfur, wt. %	0.1max	D1552
Corrosion-Copper-3 hours@ 50c	No.1 Max	D180
Micro Carbon Residue 10% Bottoms % Mass	0.1 Max	D4530
Flash Degrees C	40 min	D93
Water and Sediment, Volume %	0.05 max	D1796
Ash, wt. %	0.01max	D482
Trace Metals ppm by wt.%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Fuel Specifications Summary - Diesel

Nova Scotia Power	Combustion Turbine	Delivered March 1-Nov 30
Product Specifications		
Property	MIN/MAX	ASTM Test Method
Appearance	Clear and Bright	Visual
Density,Kg/M3	0.881	D1298
Distillation 90% Recovered	360.0 MAX	D86
Cloud Point	note 1	D2500
Pour Point(Deg C)	note 1	D97
Viscosity	1.1 min-3.6 Max	D445
Octane Number	40 MIN	D613
Sulfur, wt. %	0.1max	D1552
Corrosion-Copper-3 hours@ 50c	No.1 Max	D180
Micro Carbon Residue !05 Bottoms % Mass	0.2 Max	D4530
Flash Degrees C	40 min	D93
Water and Sediment, Volume %	0.05 max	D1796
Ash, wt. %	0.01max	D482
Trace Metals ppm by wt.%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Note: Operatbility of fuel shall meet seasonal conditions

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)	40	30	55	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

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

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 of thirty-five (35) to thirty-seven (37) millimeters or smaller and shall not contain more than three percent (3%) by volume of pieces greater than one hundred fifty (150) millimeters in length. The percentage of Biomass Fuel less than six (6) millimeters shall be less than approximately twenty-five percent (25%) of the total quantity.

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 meet the following average moisture content requirements (wet basis):

(i) Secondary forest biomass:

(a) December to May deliveries: Monthly average of fifty-five percent (55%) or less with no deliveries exceeding sixty percent (60%);

(b) June to November deliveries: Monthly average of fifty percent (50%) or less with no deliveries exceeding fifty-five percent (55%).

(ii) Primary forest biomass:

(a) December to May deliveries: Monthly average of forty-seven percent (47%) or less with no deliveries exceeding fifty-five percent (55%);

(b) June to November deliveries: Monthly average of forty-three percent (43%) or less with no deliveries exceeding fifty percent (50%).

The Biomass Fuel shall not contain a level of chlorides or metals which, in the sole discretion of NSPI, would cause damage to or interfere with the operation of the boiler or ash management programs.

Plant Performance

Capacity Factor	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1	64%	26%	13%	74%	44%	47%	45%
Lingan Unit 2	68%	15%	0%	45%	32%	23%	23%
Lingan Unit 3	56%	39%	65%	36%	49%	61%	55%
Lingan Unit 4	70%	18%	63%	72%	56%	71%	43%
Tufts Cv Unit 1	3%	37%	27%	27%	24%	6%	39%
Tufts Cv Unit 2	35%	14%	59%	8%	29%	36%	35%
Tufts Cv Unit 3	29%	63%	66%	26%	46%	26%	30%
Tufts Cv Unit 4 (LM 6000)	38%	64%	50%	48%	50%	38% (1)	54%
Tufts Cv Unit 5 (LM 6000)	40%	69%	52%	51%	53%		49%
Tufts Cv Unit 6 (LM 6000)	20%	40%	20%	28%	27%		28%
Pt Tupper	90%	54%	82%	86%	78%	83%	70%
Pt Aconi	87%	73%	65%	62%	72%	81%	74%
Trenton Unit 5	72%	49%	2%	40%	40%	14%	62%
Trenton Unit 6	91%	67%	59%	86%	76%	79%	66%
PH Biomass	43%	45%	49%	64%	50%	2%	40%

Quarterly numbers are averages of monthly figures
Definition: Capacity factor = Actual Net GWh / (Net Operating Capacity X 8760 hrs)
*The FAM Budget reflects the 2018 BCF Compliance filing of $688.1M.

Plant Performance

(1) This value represents the combined capacity factor for Tufts Cv Unit 4, 5, and 6

Availability Factor	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1	92%	68%	19%	96%	68%	67%	85%
Lingan Unit 2	97%	63%	0%	88%	62%	100%	73%
Lingan Unit 3	73%	76%	99%	60%	77%	92%	97%
Lingan Unit 4	97%	70%	92%	93%	88%	90%	91%
Tufts Cv Unit 1	79%	97%	68%	57%	75%	93%	86%
Tufts Cv Unit 2	82%	18%	81%	16%	49%	76%	77%
Tufts Cv Unit 3	92%	100%	93%	74%	90%	95%	67%
Tufts Cv Unit 4 (LM 6000)	99%	99%	75%	95%	92%	94%	95%
Tufts Cv Unit 5 (LM 6000)	98%	99%	74%	97%	92%	92%	83%
Tufts Cv Unit 6 (LM 6000)	99%	98%	54%	99%	87%	89%	90%
Pt Tupper	98%	74%	100%	100%	93%	94%	86%
Pt Aconi	99%	92%	82%	76%	87%	90%	87%
Trenton Unit 5	87%	98%	23%	71%	70%	90%	89%
Trenton Unit 6	96%	75%	83%	93%	87%	96%	75%
PH Biomass	100%	94%	77%	94%	91%	100%	82%

Quarterly numbers are averages of monthly figures
Definition: Availability = (Operating hours + ABNO Outages) / 8760 hrs
*The Annual Budget reflects the 2018 Thermal Maintence Schedule.

Plant Performance

DAFOR	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1	2.7%	3.1%	5.6%	0.1%	3.0%	1.5%	0.5%
Lingan Unit 2	2.9%	0.0%	0.0%	6.3%	3.2%	1.0%	1.5%
Lingan Unit 3	18.9%	7.0%	1.8%	0.9%	3.0%	4.2%	2.6%
Lingan Unit 4	3.5%	14.2%	8.2%	4.8%	7.5%	2.6%	2.7%
Tufts Cv Unit 1	0.0%	27.4%	32.3%	11.2%	25.2%	10.1%	7.2%
Tufts Cv Unit 2	23.0%	0.7%	0.7%	84.0%	36.6%	7.1%	6.3%
Tufts Cv Unit 3	0.0%	0.0%	5.5%	8.3%	4.1%	1.4%	1.4%
Tufts Cv Unit 4 (LM 6000)	1.0%	0.2%	1.2%	5.9%	1.8%	7.2%	1.5%
Tufts Cv Unit 5 (LM 6000)	0.0%	0.0%	1.2%	3.2%	0.8%	8.7%	8.3%
Tufts Cv Unit 6 (LM6000)	0.4%	0.2%	1.0%	3.5%	1.1%	2.0%	2.2%
Pt Tupper	2.2%	0.0%	0.4%	0.0%	0.7%	1.7%	2.2%
Pt Aconi	2.6%	1.7%	0.3%	1.0%	1.3%	3.3%	1.2%
Trenton Unit 5	6.3%	8.3%	14.2%	49.3%	12.0%	4.8%	1.8%
Trenton Unit 6	0.4%	14.1%	6.3%	0.1%	2.9%	4.0%	5.2%
PH Biomass	0.0%	0.0%	0.2%	4.1%	1.3%	~	1.7%

Quarterly numbers are averages of monthly figures
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

Plant Maintenance

OM&G and Capital Spending	Actual 2018	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Budget 2015	Budget 2016	Budget 2017	Budget 2018	Budget 2019
OM&G Expense by Operating Group										
Lingan	16.4	16.4	14.4	$17.9	$18.7	$18.8	$18.0	$16.5	$16.1	$16.3
Tufts Cove	14.6	12.1	12.5	12.2	11.8	11.8	11.9	12.1	11.8	$11.7
Pt. Tupper	7.8	8.0	7.7	8.1	7.6	8.2	8.1	8.1	7.9	$8.1
Pt. Aconi	7.8	8.1	8.0	8.5	9.6	9.2	8.9	8.3	8.1	$8.3
Trenton	13.3	14.1	13.8	14.6	14.3	14.4	14.2	13.9	13.1	$13.5
Hydro	9.6	8.1	7.8	8.0	7.7	8.3	8.1	8.2	8.0	$8.2
Wind	8.8	8.9	8.4	6.0	4.4	6.8	8.5	8.8	9.1	$8.8
Combustion Turbine	1.5	1.7	3.8	1.3	1.8	1.5	1.7	1.9	1.8	$1.8
Plant Operations	2.2	14.2	16.3	19.3	18.4	21.9	17.6	17.7	5.1	$2.2
Biomass	6.5	6.4	6.5	7.0	7.3	7.1	7.2	7.0	6.6	$6.7
Fuel, Energy & Risk Management	5.7	6.9	6.8	6.4	5.6	6.5	7.5	7.1	6.1	5.9
Total	$94.2	$104.9	$105.9	$109.3	$107.2	$114.5	$111.7	$109.4	$93.7	$91.5

Capital Spending by Station	Actual 2018	Actual 2017	Actual 2016	Actual 2015	Actual 2014	ACE Budget 2015	ACE Budget 2016	ACE Budget 2017	ACE Budget 2018	ACE Budget 2019
Lingan	$17.1	$12.2	$26.0	$29.3	$8.0	$22.5	$23.6	$10.5	$14.5	$13.2
Tufts Cove	12.1	14.9	11.7	6.0	9.6	4.7	9.7	11.3	9.0	5.4
Pt. Tupper	4.2	6.9	4.6	9.1	3.2	8.0	7.7	5.4	3.6	16.4
Pt. Aconi	14.4	17.0	11.8	9.5	11.7	9.5	10.0	11.4	10.6	9.1
Trenton	11.0	24.8	18.1	18.1	6.7	14.8	13.8	15.7	14.2	19.7
Hydro	30.2	29.8	34.9	28.6	18.7	31.1	30.0	35.3	52.8	34.8
Combustion Turbine (Includes LMs)	6.5	17.9	6.7	10.6	7.6	8.3	9.5	11.3	9.5	7.8
PH Biomass	1.3	1.1	1.1	1.2	1.6	1.0	1.1	1.2	1.2	1.2
Wind	0.2	0.5	0.1	17.0	82.9	12.2	0.1	0.1	0.2	0.5
Fuel, Energy & Risk Management	2.1	4.3	0.9	1.4	0.3	1.1	1.0	2.0	2.3	2.2
Total	$99.2	$129.4	$115.8	$130.8	$150.3	$113.2	$106.6	$104.4	$117.8	$110.4

Commentary:
For 2014 and 2015, OM&G expense is shown on a gross basis, excluding the impact of steam or other by-product sales. Previous periods have not been restated to conform to the new presentation which will be applied on a prospective basis.

Major Projects - 2018

Project	Station
CT - BGT4 Unit Restoration	Combustion Turbine
Engine 191-253 Engine Refurbishment	Combustion Turbine
CT's Tusket Replace Generator	Combustion Turbine
CT - Routine Equipment Replacements	Combustion Turbine
HYD Lequille Headpond Refurbishment	Hydro
HYD - WRC Tailrace Rock Bolting	Hydro
HYD Mersey Redevelopment Phase 1	Hydro
HYD WRC Tunnel T-2 Intake Replaceme	Hydro
HYD - ANN HVAC Upgrade	Hydro
HYD - Fourth Lake Overhaul	Hydro
HYD - 4th Lake Penstock Refurb	Hydro
HYD UU LEQ Stator Refurbishment	Hydro
HYD WRC U1 WG Thrust Assembly	Hydro
HYD - Routine Equipment Replacement	Hydro
HYD - PE Tusket Falls Main Dam	Hydro
HYD - Bridge Remediation	Hydro
HYD - Milton Shop HVAC Upgrade	Hydro
HYD - Gulch Spillway Refurbishment	Hydro
HYD LEQ Plant Output Cable Replacem	Hydro
HYD - Gulch Penstock Surge Tank	Hydro
HYD - WRC HVAC Upgrade	Hydro
HYD - ULF #2 Overhaul	Hydro
HYD - WRC Main Access Rd Refurb	Hydro
HYD- Wreck Cove Machine LEM PE	Hydro
HYD UU Big Falls Exciter Replacemen	Hydro
HYD - Lequille Controls Upgrade	Hydro
HYD - Security Improvement	Hydro
HYD - UU WRC 2 Stator Re-Wedging	Hydro
HYD - Hells Gate 2 Overhaul	Hydro
LIN1 P&A Boiler Refurbishment	Lingan
LIN4 Boiler Refurbishment 2018	Lingan

Plant Maintenance

Major Projects - 2018

Project	Station
LIN Mill Refurbishment 2018	Lingan
LIN3 - Boiler Refurbishment 2018	Lingan
LIN3&4 CEM Replacement	Lingan
LIN CW Pump Refurbishment 2018	Lingan
LIN1 SH5 Tube Replacement	Lingan
LIN4 RH Tube Replacement	Lingan
LIN3 RH Tube Replacement	Lingan
LIN3 UU BA Refurbishment 2018	Lingan
LIN3 ID Fan VIVs	Lingan
LIN1 BA Refurbishment 2018	Lingan
LIN Coal Plant Structural Refurbis	Lingan
LIN - Routine Equipment Replacement	Lingan
LIN3 Turbine Valve Refurb 2018	Lingan
LIN3 UU Burner Front Component Repl	Lingan
LIN-Roofing Routine	Lingan
PHB Boiler Refurbishment 2018	PH Biomass
POT Boiler Refurbishment 2018	Pt Tupper
POT - B Coal Mill Refurbishment	Pt Tupper
POT Turbine Valve Refurbishment	Pt Tupper
POT Coal Mill Overhaul 2018	Pt Tupper
POT - Routine Equipment Replacement	Pt Tupper
POA Ash Cell 5	Pt. Aconi
POA Boiler Refurbishment 2018	Pt. Aconi
POA Boiler Refractory 2018	Pt. Aconi
POA UU Limestone Cyclone Refurbisme	Pt. Aconi
POA SH3 Tube Replacements	Pt. Aconi
POA Air Heater Tube Replacement	Pt. Aconi
POA LS Crusher Refurbishment	Pt. Aconi
POA UU RH Tube Refurbishment 2018	Pt. Aconi
POA UU 4160V Coal Tran Cable Replac	Pt. Aconi

Major Projects - 2018

Project	Station
POA LS System Refurbishment	Pt. Aconi
POA Coal System Refurbishment	Pt. Aconi
POA CW Screen Refurbishment 2018	Pt. Aconi
TRE5 Boiler Refurbishment 2018	Trenton
TRE Asbestos Abatement 2018	Trenton
TRE6 CEMS Replacement	Trenton
TRE5 Reheat Turbine Valves	Trenton
TRE5 Mill Refurbishments 2018	Trenton
TRE - Routine Equipment Replacement	Trenton
TRE5 Baghouse Bag Replacement P&A	Trenton
TRE6 EHG/Turbine Ctrls Upgrade	Trenton
TUC HFO Piping Refurbishment	Tuft's Cove
TUC6 CW Screen Replac	Tuft's Cove
TUC2 Generator Flux Probe Installat	Tuft's Cove
TUC1 Boiler Refurbishment	Tuft's Cove
TUC2 Generator Bushing Replacement	Tuft's Cove
TUC2 H2 Panel Upgrades	Tuft's Cove
TUC3 IP Turbine Refurbishment	Tuft's Cove
TUC HFO Tank Dyke Piping Refurb	Tuft's Cove
TUC - Routine Equipment Replacement	Tuft's Cove
TUC2 CEMS	Tuft's Cove
TUC6 Main and Induction Stop Valve	Tuft's Cove
ICP UU Armour Stone Replacement	Fuel, Energy & Risk Management
PTMT - Dock winching and access	Fuel, Energy & Risk Management

Plant Maintenance

Major Projects - 2019

Project	Station
TUC 4 Engine S/N 191-332 Hot Sec	Combustion Turbine
LM6000 TUC4 Control System Replace	Combustion Turbine
LM6000 TUC4 Airhouse Upgrade	Combustion Turbine
LM6000 TUC5 Airhouse upgrade	Combustion Turbine
HYD Gaspereau Dam Safety	Hydro
HYD - Hells Gate 1 Overhaul	Hydro
CT-BGT Replace Halon Fire Protectio	Hydro
HYD Bridge Replacements	Hydro
HYD Fixed Ladder & Machine Guard	Hydro
HYD - Routine Equipment Replacement	Hydro
HYD - Security Improvement	Hydro
HYD Mersey Redevelopment Phase 1	Hydro
HYD Nictaux Canal Embank Refurb	Hydro
HYD PE Ruth Falls Main Dam Refurb	Hydro
HYD - Malay 6 Overhaul	Hydro
HYD - MAL 6 Generator Refurb	Hydro
HYD - Ruth Falls Facility Refurb	Hydro
HYD - Tidewater 2 Overhaul	Hydro
HYD - PE Tusket Falls Main Dam	Hydro
HYD - WRC Tailrace Rock Bolting	Hydro
HYD - WRC Main Access Rd Refurb	Hydro
HYD - Wreck Cove Controls Upgrade	Hydro
HYD WRC Crane Refurbishment	Hydro
HYD - WRC Safety Standards Upgrades	Hydro
LIN3 Boiler Refurbishment	Lingan
LIN 1&2 CEMS Replacement	Lingan
LIN4 Boiler Refurbishment	Lingan
LIN Mill Refurbishments 2019	Lingan
LIN Reclaim Refurbishment Phase 3	Lingan
LIN CW Pump Refurbishment 2019	Lingan
LIN4 Economizer Header Refurb.	Lingan
PHB - Boiler Refurbishment 2019	PH Biomass

Major Projects - 2019

Project	Station
POT - Generator auxiliary equipment	Pt Tupper
POT - IP-LP turbine refurbishment	Pt Tupper
POT - HP Turbine refurbishment	Pt Tupper
POT - Boiler Refurbishment 2019	Pt Tupper
POT - Fire system upgrades 2017	Pt Tupper
POT-Turbine Valve Refurbishment	Pt Tupper
POT - Air heaters refurbishment	Pt Tupper
POT Coal Mill Refurbishment 2019	Pt Tupper
POT - Hydrogen panel replacement	Pt Tupper
POA Boiler Refurbishment	Pt. Aconi
POA PE ID Fan Motor Replacment	Pt. Aconi
POA Boiler Refactory Replacement	Pt. Aconi
POA SH3 Boiler Tube Rep. Phase IV	Pt. Aconi
TRE HFO System Upgrades Phase 2	Trenton
TRE Trenton Ash Site Closure	Trenton
TRE Rail Car Fuel Delivery Upgrade	Trenton
TRE6 Boiler Refurbishment	Trenton
TRE Asbestos Abatement 2019	Trenton
TRE6 Mill Refurbishment 2019	Trenton
TRE5 Turbine Main Valves	Trenton
TRE6 Generator HVB Replacement	Trenton
TRE6 EHG/Turbine Ctrls Upgrade	Trenton
TRE5 Baghouse Filter Replacement	Trenton
TRE5 Condenser Inlet Piping Replace	Trenton
TRE5 Boiler Refurbishment 2019	Trenton
TRE Sludge Dewatering Infrastructur	Trenton
TUC Heavy Fuel Oil Tank Dyke Refurb	Tuft's Cove
TUC UT3 and ST34 Cabling Replacemen	Tuft's Cove
ICP - Rail System Refurbishment 201	Fuel, Energy & Risk Management

System Losses

GWh	Actual 2018	Actual 2017	Budget 2018*	Budget 2019**
Total System Requirements	11,361.9	10,976.6	11,309.9	11,331.1
Domestic Electric Sales	10,528.0	10,144.3	10,538.9	10,555.5
Export Sales	88.5	100.4	50.0	50.0
Net System Losses	745.3	732.0	721.0	725.6
%	6.6%	6.7%	6.4%	6.4%

* 2018 Budget reflects the 2018 BCF Compliance filing of $688.1M.
** 2019 Budget reflects the 2018 BCF Refresh filing of $653.7M.

Emission Compliance

Commentary

Nova Scotia Power (NSPI) is required to manage air emissions to annual fleet wide limits, as per the NS Air Quality Regulations and the NS Greenhouse Gas (GHG) Emissions Regulations. NSPI has been fully compliant with legislated emission targets each year.

The fleet wide limit of sulphur dioxide (SO2) emissions for 2015-2019 inclusive is 304,500 tonnes.The emissions of SO_2 for 2018 are estimated at 61.8 ktonnes. The SO2 emissions for 2018 will be finalized and third-party verified by March 31, 2019 as per Provincial reporting requirements.

The 2018 limit on annual emissions of mercury (Hg) was 65 kg. NSPI continued the operation of seven (7) sorbent injection systems that were installed in 2009. The mercury emissions were within this limit in 2018 at 63.4 kg (estimate). The Hg emissions for 2018 will be finalized and third-party verified by March 31, 2019 as per Provincial reporting requirements. The 2019 emission limit for mercury will remain at 65 kg. Under current regulations, any NSPI emissions of Hg above 65 kg for 2010-2013 must be made up by 2020. A mercury diversion program that began in 2015 and was executed under the Air Quality Regulations continued in 2018. NS Power took the opportunity to obtain mercury credits through the diversion of mercury containing products from the environment in Nova Scotia. Mercury diversion credits for 2018 are estimated at 58.1 kg. The mercury diversion report and verification for 2018 will be submitted to the Department on, or before March 31, 2019 in accordance with Section 7F of the Air Quality Regulations. The mercury diversion program will be continuing in 2019.

NSPI manages its actual air emissions (SO_2 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 generating electricity from renewable sources.

From 2015 to the end of 2019 there is a compliance limit total of 96,140 tonnes for nitrogen oxides (NOx) emissions.The 2018 NOx emissions are estimated at 14.8 ktonnes. The NOx emissions for 2018 will be finalized and third-party verified by March 31, 2019 as per Provincial reporting requirements. NSPI continued the operation of the low NO_x Combustion Firing Systems (LNCFS) on all Lingan units, Point Tupper and Trenton 6. These LNCFS additions represent the primary approach to reduce NO_x emissions.

The GHG emission limit for the three-year period of 2017-2019 has been set at 24.06 million tonnes CO2 eq. This equates to the approximate target of 8.02 million tonnes per year from 2017 to 2019. The 2018 GHG emissions are estimated at 6.9 million tonnes. The GHG emissions for 2018 will be finalized and third-party verified by June 1, 2019 as per Provincial reporting requirements.

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 2018
The PAC systems were run to achieve compliance in 2018. Emissions were closely monitored to optimize injection rates.
Final performance of 63.4 kg was achieved within the target period.

Testing:
PAC testing was conducted in Q1, Q2, and Q4 at Lingan. The purpose of the testing was to determine the suitability of new sulphur-tolerant PAC products offered by NSPI's current PAC supplier. This testing will continue in 2019.

Calcium Chloride 2018
Calcium chloride systems are installed at each plant. The systems are run as required, based on fuel blend.

Mercury Abatement Program
Technical / Capital Changes

Option	Description	Anticipated Result
NA		